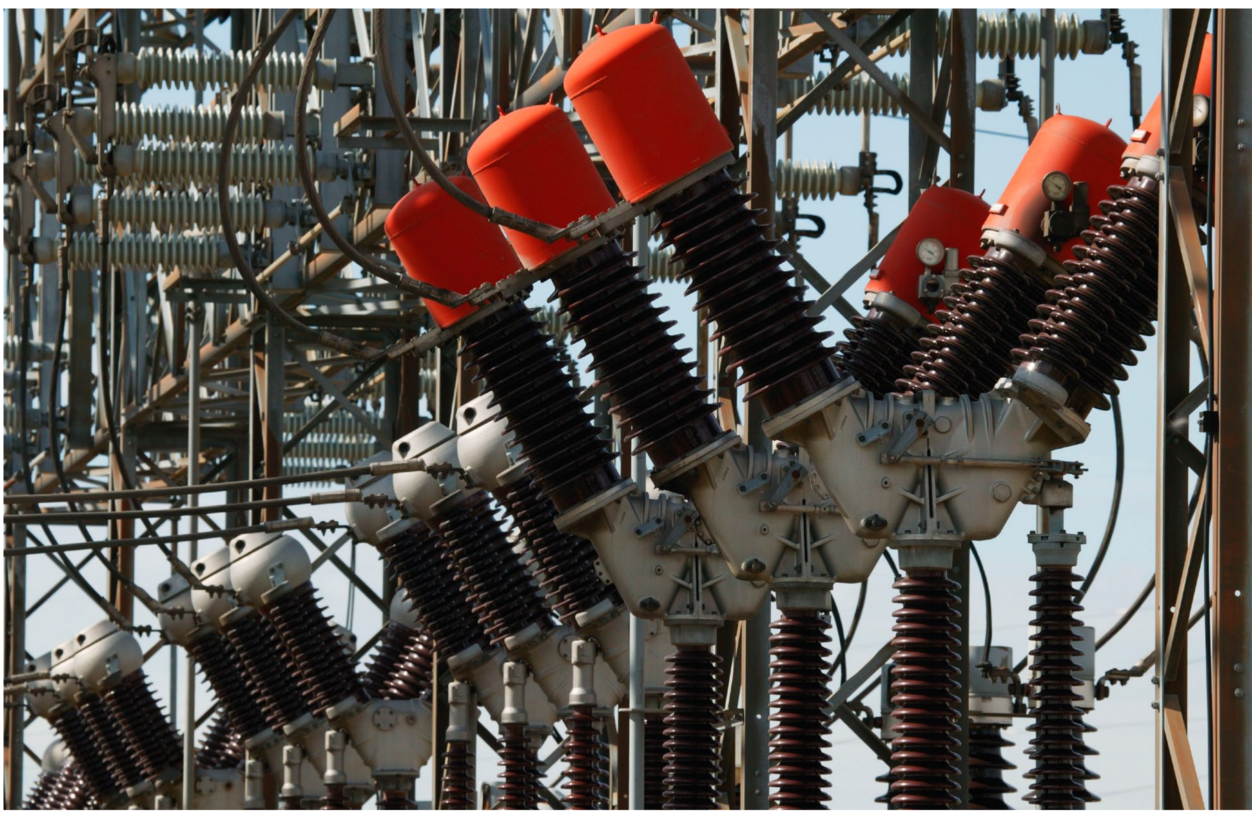
Energy & Resources
Accounting, Financial Reporting, and Tax Update

January 2012



Contents

Foreword

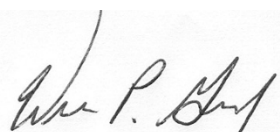
January 2012

As our industry continues to confront the challenges of changing markets, new legislation, and emerging businesses and technologies, finance practitioners face new challenges in navigating the related tax, accounting, and reporting implications. In an effort to help you meet these challenges currently and in the coming months, we are pleased to present Deloitte's tenth 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 along with a focus on specialized industry accounting topics frequently seen by rate-regulated entities. We also outline emerging accounting and reporting concerns specific to renewable energy.

To help you understand and address potential challenges related to the accounting and reporting of revenue, leases, financial instruments and a host of other topics as a result of several proposed standards issued by the FASB, we have included a section about the Board's proposals and have highlighted nuances that could impact our industry.

This year's update includes those timeless considerations as well as new and emerging 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 14, 2011, covering highlights from the 2011 AICPA National Conference on Current SEC and PCAOB Developments.

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



William P. Graf
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Section 1
Industry Developments

Outlined below are some of the issues and trends that have affected entities in the P&U[1] sector that are not addressed in the rest of this publication.

Merger and Acquisition Activity

There was a significant uptick in merger and acquisition activity in 2011 in the E&R industry. The volume of transactions more than tripled, signaling a wave of potential industry consolidation and reconfiguration. The following are details on some of the more significant transactions announced during 2011:

- *Duke Energy Corporation and Progress Energy Inc.* — On January 8, 2011, Duke Energy Corporation announced it will issue shares of its common stock to acquire each outstanding share of Progress Energy Inc. Duke Energy will also assume approximately $12.1 billion of Progress Energy's debt. The merger has an announced transaction value of $25.7 billion.

- *AES Corporation and DPL Inc.* — On April 19, 2011, AES Corporation announced it will pay $30 per share in cash and assume approximately $1.2 billion in debt to acquire DPL Inc. The announced transaction value associated with this acquisition is $4.6 billion.

- *Exelon Corporation and Constellation Energy Group Inc.* — On April 28, 2011, Exelon Corporation announced it will issue shares of its common stock to acquire each outstanding share of Constellation Energy Group Inc. In addition, Exelon will assume approximately $2.9 billion of Constellation Energy Group's debt. The announced transaction value is $10.6 billion.

- *Energy Transfer Equity L.P. (ETE) and Southern Union Company (SUG)* — On June 15, 2011, ETE agreed to acquire SUG for $44.25 per share in cash or issue one share of ETE's common units for each SUG common unit. ETE will also assume approximately $3.7 billion of SUG's debt. The announced transaction value is $9.4 billion.

- *Kinder Morgan Inc. and El Paso Corp.* — In October, Kinder Morgan Inc. announced its plans to acquire El Paso Corp. in a transaction that would potentially create the nation's largest midstream company and natural gas transporter.

- *Entergy Corp. and ITC Holdings Corp.* — In December, Entergy Corp. announced its plans to spin off its transmission business, which would be acquired by ITC Holdings Corp.

To gain financial scale, reduce costs, and increase the flexibility of investments needed to solve equations related to demand, supply, and infrastructure, many utilities and power producers will rely on mergers and acquisitions as a key intermediate-term strategy. However, the business case for mergers and acquisitions must also be clear to state regulators and legislators. A company must be able to clearly demonstrate customer benefits as well as the impact on rates, the workforce, and the tax base; otherwise, approvals at the state level may be elusive.

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

On March 11, 2011, Japanese authorities informed the Incident and Emergency Centre of the International Atomic Energy Agency (IAEA) that officials were working to restore power to the cooling systems of the Unit 2 reactor at the Fukushima Daiichi nuclear power plant (Fukushima) operated by Tokyo Electric Power Company in Okuma, Fukushima, Japan. The loss of power was the result of the magnitude 9 earthquake that generated a series of large tsunami waves that struck Japan on March 11. In the hours and days that followed, Units 1–3 at Fukushima experienced a full meltdown, while the remaining Units (4–6) experienced varying levels of structural damage but did not melt down. The Fukushima disaster was the largest nuclear accident since the Chernobyl incident in 1986 and was classified as a level 7 (the most severe) event on the IAEA's International Nuclear Event Scale.

[1] For a list of abbreviations used in this publication, see Appendix A.

The ramifications of the Fukushima disaster on the nuclear power industry are far reaching. Before the incident, the IAEA had projected between 143 and 416 nuclear reactors to be added globally by 2030. Those estimates have subsequently been revised to between 90 and 350 reactors. A flurry of petitions was received by the U.S. Nuclear Regulatory Commission (NRC) after the Fukushima incident in which the NRC was asked to conduct safety and regulatory analyses of the events at Fukushima as well as to suspend licensing and design certifications. On September 13, 2011, the NRC released an order to the public denying the request to suspend all licenses but followed the order with the approval in October of seven new safety measures for nuclear power plants.

Rate-Case Activity

Rate-case activity continued at a significant level during 2011. Increased costs, including those as a result of generation and other infrastructure upgrades and expansion projects, environmental compliance expenditures, and renewable generation mandates, indicate that an elevated level of rate-case activity will continue over the next few years. Integrated resource plans are being adjusted and reconfigured to reflect the known or potential impacts of environmental legislation and the resulting economics. In certain jurisdictions, companies or their regulators have proposed rate-making strategies designed to mitigate or neutralize the impact of revenue requirement increases or, in some cases, to even reduce rates. Entities must thoroughly evaluate these rate-making strategies to make sure the impacts of financial accounting and tax law are appropriately considered.

Renewable Energy

Renewable energy continues to be a hot topic for the E&R industry. As utilities enter or continue to expand their presence in the renewable energy market, several issues need to be considered. Perhaps the biggest question facing renewable energy at this time is whether the supply chain is adequate to create and distribute energy on a large scale. For renewable energy to grow into a sustainable source of energy, there must be a commitment to scaling up renewable energy infrastructure without compromising reliability. Furthermore, with respect to wind generation, ideal sites are typically located in fairly unpopulated rural areas, which can create problems with the storage and delivery of energy to heavily-populated markets.

The continued development of the renewable energy market will also depend heavily on companies' ability to continue to finance renewable sites on a project-by-project basis. Renewable energy projects will be competing for funds against much larger traditional energy infrastructure projects, which could pose difficulties in the ability of companies to secure financing. Construction costs associated with renewable projects, while decreasing, may still be projected to be higher than construction costs for nuclear or fossil fuel plants when such costs are viewed on a per-kilowatt basis. In addition, the current economic environment has placed government spending under increased scrutiny, which could translate into reduced tax and regulatory incentives for utilities. The attention surrounding the bankruptcy of solar panel manufacturer Solyndra Inc. has caused some reflection on the level of assistance the market should receive from the federal government.

Notwithstanding the above considerations, companies are likely to continue to develop renewable energy portfolios to meet a greater portion of their generation requirements over the coming years, especially given increased environmental regulation and restrictions on carbon emissions and requirements in some states to meet minimum renewable energy levels.

See Section 10 for additional considerations related to renewable energy.

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.

Shale gas continues to emerge as a viable and affordable alternative to coal. With roughly half the carbon dioxide emissions of coal, the demand for shale gas is likely to continue to grow, in turn pushing North American natural gas prices higher. This increased activity could eventually make shale the dominant component of U.S. gas production. Deloitte's Center for Energy Solutions currently predicts that shale gas output will bolster gas production, growing from approximately 66 billion cubic feet per day (bcfd) in 2011 to almost 79 bcfd in 2018.

Growth in gas demand for power generation is expected over the next 20 years as environmental regulations and restrictions accelerate the retirement of U.S. coal-fired power plants.

However, U.S. shale gas supply is finite, and shale production costs will be a key factor in the feasibility of shale gas as a long-term replacement to coal-fired generation. While the combination of horizontal drilling and hydraulic fracturing have allowed access to large volumes of shale gas that were previously uneconomical to produce, as more easily accessed shale gas is depleted, more technically challenging supplies will need to be tapped and produced, leading to increased production costs.

Section 2
SEC Update

This section summarizes recent accounting and reporting guidance from the SEC as well as other related guidance that may affect E&R registrants.

Proxy, Risk, Compensation, and Corporate Governance Guidance Updates

Stay on Proxy Access Rule Amendments

The SEC issued a stay on Final Rule 33-9136[2] (its "proxy access" rule), which allows shareholders to use company proxy documents to nominate director candidates. Issued on October 4, 2010, the stay was granted as a result of a petition filed on September 29, 2010, by the Business Roundtable and the Chamber of Commerce of the United States with the United States Court of Appeals.

On July 22, 2011, Final Rule 33-9136 was vacated by the United States Court of Appeals for the District of Columbia Circuit and therefore is not effective.

Listing Standards for Compensation Committees

The SEC issued a proposed rule that would require national securities exchanges and associations to establish listing standards for listed entities that have compensation committees or that engage compensation consultants or advisers. The proposed rule and rule amendments were issued on March 30, 2011, and were developed to address the requirements of Section 952 of the Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act"), which adds Section 10C to the Securities Exchange Act of 1934 (the "Exchange Act").

The proposed rule would prohibit listing the equity securities of entities on exchanges that do not comply with the new requirements. The most notable items required by the listing standards include the following:

- Compensation committee members are to be independent members of the board of directors.
- Adoption of disclosure requirements in proxy materials for annual or special shareholder meetings regarding the use of compensation consultants and whether any conflicts of interest were identified through the compensation consultant's work. If applicable, an issuer would also be required to disclose how such conflicts are being addressed.

In addition, issuers' compensation committees would be required to:

- Have the sole discretionary authority to engage and direct or oversee the work of compensation consultants.
- Weigh specific independence factors, as indicated by the SEC, when selecting compensation consultants.
- Provide appropriate funding to reasonably compensate such consultants, as determined by the compensation committee.

"Say on Pay" and "Say on Golden Parachutes"

On January 25, 2011, the SEC issued a final rule on "say-on-pay" and "say-on-golden-parachute" provisions under Section 951 of the Dodd-Frank Act. The rule requires entities to conduct say-on-pay votes once every three years (beginning with the first annual shareholders' meeting on or after January 21, 2011). Frequency votes to allow shareholders to determine how often they would like to have the say-on-pay votes are also required once every six years. In addition, the rule requires disclosure of certain golden-parachute compensation arrangements when shareholder votes are solicited to approve a merger or acquisition and would call for separate advisory votes to approve golden-parachute arrangements under certain circumstances. The rule also provides for a two-year deferral for smaller reporting companies.

[2] For the full titles of standards and other literature or links to them, see Appendix B.

Activities Related to Requirements Under the Dodd-Frank Act

Certain provisions of 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 Adopts Mine Safety Disclosure Requirements

To comply with Section 1503 of the Dodd-Frank Act, the SEC issued a final rule on mine safety disclosure requirements on December 21, 2011. Under the new SEC rule, registrants "that are operators, or that have a subsidiary that is an operator, of a coal or other mine," would be required to provide periodic reports to the SEC regarding "health and safety violations, orders and citations, related assessments and legal actions, and mining-related fatalities." The final rule will be effective January 27, 2012.

Conflict Minerals and Extractive Industry Disclosures

To comply with Sections 1502 and 1504 of the Dodd-Frank Act, respectively, the SEC issued the following proposed rules on December 15, 2010, that would require specialized disclosures about conflict minerals and government payments by issuers that extract oil, natural gas, or minerals ("resource extraction issuers"):

- Conflict Minerals — Registrants would be required to disclose, in their annual report, whether the origin of their conflict minerals (when these materials are necessary to the functionality or production of a product) was the Democratic Republic of the Congo or any adjoining country. In such cases, the registrant "would be required to furnish a separate report as an exhibit to its annual report that includes, among other matters, a description of the measures taken by the [registrant] to exercise due diligence on the source and chain of custody of its conflict minerals." Such a report would have to be audited in accordance with the standards of the comptroller general of the United States.

- Disclosure of Payments by Resource Extraction Issuers — Resource extraction issuers would be required "to include in an annual report information relating to any payment made by the issuer, or by a subsidiary or another entity controlled by the issuer, to a foreign government or the Federal Government for the purpose of the commercial development of oil, natural gas, or minerals." The information required would include the "type and total amount of payments made."

ABS Credit Risk Retention Requirements

On March 30, 2011, the SEC, jointly with five other federal agencies, issued a proposed rule to implement requirements for issuers or sponsors ("securitizers") of asset-backed securities (ABSs). Under the proposed rule, securitizers would retain a portion of the credit risks associated with the assets collateralizing the ABSs, in accordance with (1) Section 15G of the Exchange Act and (2) Section 941 of the Dodd-Frank Act. In addition, the proposed rule requires disclosure of material information related to the securitizer's interest in a securitization transaction. The proposed risk retention requirements would apply to all securitizers of ABS offerings (i.e., regardless of whether the offering is registered with the SEC under the Securities Act of 1933 (the "Securities Act")).

One of the objectives of the proposed rule is to address what some believed to be a critical weakness in the securitization market that led to the financial crisis. The SEC believes that to ensure that securitizers have the incentives to monitor the quality of the securities, some meaningful risks need to be retained. Therefore, under the proposed rule, securitizers would be:

- Required to retain no less than 5 percent of the credit risk of assets within an ABS.

- Prohibited from hedging or transferring the credit risk that they are required to retain.

- Required to apply a "premium capture" mechanism, in which a securitizer is prevented from structuring a deal that could reduce its retained exposure below the minimum amount.

The proposal permits securitizers to select a form of risk retention from a menu of specified options, which is intended to allow them some flexibility in retaining credit risks. Among the options are (1) "vertical" risk retention achieved by holding, at a minimum, 5 percent of each class of ABS; (2) "horizontal" risk retention made up of a "first-loss residual interest" for all ABS interests issued; (3) "L-shaped" risk retention consisting of an equal combination of vertical and horizontal retentions; and (4) a premium capture cash reserve account prohibiting distribution of "excess spread" cash flows to a securitizer.

The proposed rule also indicates that some offerings would be exempt from the risk retention requirements, including ABSs that are collateralized exclusively by "qualified residential mortgages," which are determined on the basis of loan-to-value and loan-to-income ratios, minimum down payments, and borrowers' credit history, among other things.

Asset-Backed Securities

On January 20, 2011, the SEC issued the following final rules on offerings of ABSs under Sections 943 and 945 of the Dodd-Frank Act:

- Final Rule 33-9175, which (1) requires securitizers of ABSs to provide tabular disclosures in various filings of fulfilled and unfulfilled repurchase requests for an initial three-year "lookback" period ending December 31, 2011, and quarterly thereafter and (2) requires nationally recognized statistical ratings organizations to "include information regarding the representations, warranties and enforcement mechanisms available to investors in an [ABS] offering in any report accompanying a credit rating issued in connection with such offering, including a preliminary credit rating." Effective dates vary on the basis of the filings required by certain rules and regulations discussed in the final rule.

- Final Rule 33-9176, which:

  - Requires "any issuer registering the offer and sale of an [ABS] to perform a review of the assets underlying the ABS." However, the final rule clarifies that an issuer may hire a third party to perform the review as long as the issuer (1) names the third party and (2) obtains the third party's consent if the issuer relies on, or attributes the ABS asset pool review findings and conclusions to, the third party.

  - Specifies a minimum review standard that requires the issuer to obtain "reasonable assurance" that pool asset disclosures are "accurate in all material respects."

  - Requires an ABS issuer to provide additional disclosures, including disclosures about (1) the nature of the issuer's review of the asset pool and the related findings and conclusions and (2) additional information regarding assets in the pool that do not meet underwriting standards.

Issuers of registered ABS offerings are expected to comply with the final rule, beginning with initial bona fide offers after December 31, 2011.

Conflicts of Interest in Certain Asset-Backed Securities Transactions

On September 19, 2011, the SEC approved a proposed rule that would implement the prohibition in Section 621 of the Dodd-Frank Act related to material conflicts of interest.

Under the proposal, ABS securitization participants would be prohibited (for one year from the first closing of an ABS offering) from engaging in certain transactions that "involve or result in any material conflict of interest between the securitization participant and any investor in an ABS that the securitization participant created or sold." The proposed rule affects offerings of both synthetic and nonsynthetic ABSs, whether registered or unregistered. The proposal also outlines a two-condition test for identifying transactions in which a material conflict of interest exists.

Security Ratings

In accordance with Section 939A of the Dodd-Frank Act, the SEC unanimously adopted a final rule that addresses the use of credit ratings in the offering of securities ("security ratings"). The final rule, issued on July 27, 2011, is substantially similar to the rule proposed in February 2011.

The rule replaces requirements that rely on, or make special accommodations for, security ratings offered on short-form or "shelf" registration statements (e.g., Forms S-3 and F-3) with alternative requirements. Thus, the proposed rule may affect certain registrants' eligibility to use shelf registration statements.

Registrants have included security ratings information in Forms S-3 and F-3 because a way for them to be eligible to offer nonconvertible securities on a shelf registration statement is for such securities to be rated "investment grade" by at least one nationally recognized statistical rating organization. The rule proposes requirements similar to those related to a registrant's attaining well-known seasoned issuer (WKSI) status. Most notable is the need for the issuer to have offered at least $1 billion of nonequity and nonconvertible securities under the Securities Act for cash within the past three years — measured within 60 days of the filing of the registration statement (subject to certain provisions).

With certain exceptions, the rule became effective on September 2, 2011.

Proposal to Remove References to Credit Ratings Under the Exchange Act

In accordance with Section 939 of the Dodd-Frank Act, the SEC issued a proposed rule on April 27, 2011, that would require the SEC to (1) remove references to, or requirements that rely on, credit ratings in certain rules and forms under the Exchange Act and (2) replace such references with an appropriate substitute standard of creditworthiness. The proposed rule is the third proposal related to credit ratings recently issued by the SEC. The other proposals would (1) change the securities in which money market funds could invest to those "that have received . . . one of the two highest ratings of [short-term borrowings]" and (2) remove and replace credit ratings for short-form registration statement eligibility with requirements similar to those that registrants need to obtain WKSI status.

This proposal would amend certain rules and forms related to broker-dealer financial responsibility, distributions of securities, and confirmations of transactions. The SEC has also requested constituents to comment on potential standards of creditworthiness for "mortgage related security" and "small business related security" as defined in Sections 3(a)(41) and 3(a)(53) of the Exchange Act.

Proposed Rules on Security-Based Swaps

As a result of the Dodd-Frank Act, the SEC proposed the following new rules in connection with security-based swaps:

- Security-Based Swap Data Repository Registration, Duties, and Core Principles (issued November 19, 2010).
- Regulation SBSR — Reporting and Dissemination of Security-Based Swap Information (issued November 19, 2010).
- Prohibition Against Fraud, Manipulation, and Deception in Connection With Security-Based Swaps (issued November 3, 2010).

Exemptive Order for Temporary Exemption and Relief From New Security-Based Swap Regulations

On June 15, 2011, the SEC issued an exemptive order that grants temporary relief to market participants from complying with certain requirements under Title VII of the Dodd-Frank Act for security-based swap transactions. The order also identifies certain requirements that will apply (as planned) to security-based swap transactions as of the July 16, 2011, effective date and provides temporary relief from Section 29(b) of the Dodd-Frank Act, which voids any contracts made in violation of any provision of the Exchange Act.

Regulation of OTC Derivatives

Title VII of the Dodd-Frank Act establishes a comprehensive framework for regulating OTC derivatives. It gives the SEC the authority to regulate "security-based swaps" and was intended to take effect on July 16, 2011, approximately one year after the Dodd-Frank Act's enactment date. Anticipating that it would not meet the Act's mandated deadlines for certain provisions under Title VII, the SEC issued three interim temporary rules on July 1, 2011, and July 7, 2011, that address clearing agencies, credit default swaps, and security-based swaps. In addition, the SEC plans to develop a detailed plan to ensure that the Title VII regulations can be implemented efficiently and cost-effectively.

Whistleblower Regulations

On May 25, 2011, the SEC issued a final rule (which passed narrowly by a 3–2 vote) to implement the whistleblower provisions under Section 21F (added by Section 922 of the Dodd-Frank Act) of the Exchange Act. The final rule provides financial rewards for whistleblowers who give the SEC "original information" leading to securities law enforcement actions that recover more than $1 million. Whistleblowers are encouraged, but not required, to report the information internally before reporting it to the SEC. In addition to addressing the amount of and eligibility criteria for the awards, the final rule discusses the antiretaliatory provisions of Section 21F as well as the eligibility to receive an award of whistleblowers who are themselves culpable of misconduct.

To administer the whistleblower program, the SEC created the Office of the Whistleblower, which is responsible for handling whistleblower tips and complaints and determining and providing awards.

Exemption From Section 404(b) for Nonaccelerated Filers

On September 15, 2010, the SEC issued a final rule that states that under Section 404(c) of the Sarbanes-Oxley Act of 2002, Section 404(b) is not applicable to "any audit report prepared for an issuer that is neither an accelerated filer nor a large accelerated filer as defined in Rule 12b-2 under the Securities Exchange Act of 1934."

The guidance in the final rule became effective on September 21, 2010.

Findings and Recommendations From Study on Compliance With Section 404(b)

The SEC published findings and recommendations in response to its September 2010 request for comments about how the SEC could reduce the costs associated with compliance with Section 404(b) of the Sarbanes-Oxley Act of 2002. The study was mandated by Section 989G(b) of the Dodd-Frank Act. Section 404(b) only addresses the auditor attestation requirement related to a company's ICFR.

On the basis of the results of the study, the SEC (1) concluded that "auditor involvement promotes more accurate and reliable reporting" in the assessment of ICFR and (2) made the following two broad recommendations:

- Section 404(b) should continue to apply to domestic registrants and foreign private issuers whose market capitalization is between $75 million and $250 million. The SEC did not recommend a permanent exemption from Section 404(b) because the study did not conclusively show that (1) the benefit of any cost savings from such an accommodation would justify the loss of investor protections or (2) such cost savings would result in an increase or a decrease in initial public offerings, because the cost of complying with Section 404(b) is only one of many factors companies consider when deciding whether to access the U.S. capital markets.

- Activities should be identified and implemented that could further improve how Section 404(b) is applied. For example, the SEC suggested that the PCAOB consider offering observations on the basis of what it notes in conducting inspections of PCAOB-registered firms.

Compliance and Disclosure Interpretations

The SEC's Division of Corporation Finance periodically issues or updates Compliance and Disclosure Interpretations (C&DIs) of topics that may be of interest to E&R companies. Some recently issued C&DIs are summarized below.

Tagging of Information in XBRL

In September 2010, the following C&DIs on the tagging of information in XBRL were updated:

- Questions 14–16 of Section 146 on Regulation S-K, Item 601.
- Question 10 of Section 130 on Regulation S-T, Rule 405.
- Question 1 of Section 131 on Regulation S-T, Rule 406T.

In addition, Questions 5 and 6 were withdrawn from Section 105 on Exchange Act forms under Form 10-Q.

Changes in Accountants

New C&DIs were issued in January 2011 on disclosures about changes in accountants, as required by Regulation S-K, Item 304, and Form 8-K, Item 4.01. The Regulation S-K disclosures are required for a registrant's two most recent fiscal years and any subsequent interim period. The following C&DIs were added:

- Regulation S-K, Item 304:
  - Question 111.01 — Clarifies the term "subsequent interim period."
  - Question 111.02 — Indicates that no affirmative response is needed if there are no reportable events.
  - Questions 111.03 and 111.04 — Specify that a registrant is required to disclose a material weakness identified by a former principal accountant or its remediation.
  - Questions 111.05 and 111.06 — Note that disclosure is required when former principal accountants issue (1) audit reports on a registrant's financial statements "containing an explanatory paragraph regarding a registrant's ability to continue as a going concern," when these reports constitute a report modification, or (2) audit reports on a registrant's ICFR that include modifications, adverse opinions, or disclaimers of opinions.
  - Question 111.07 — Clarifies that a registrant should disclose the reason for a change in accountant if the change is due to revocation of the accountant's PCAOB registration.
- Form 8-K, Item 4.01: Questions 114.01–03.

Say-on-Pay Requirements

In February 2011, new C&DIs were issued related to "say on pay," "say on frequency," and golden parachute votes and disclosures in a proxy statement. The new C&DIs include the following:

- Exchange Act Rules, Section 169 — Rule 14a-21:
  - New Questions 169.01, 169.02, and 169.03 — Clarify the application of the following to smaller reporting companies: (1) shareholder approval of executive compensation, (2) frequency of votes, and (3) approval of golden parachute compensation in a merger or acquisition.
  - New Question 169.04 — Explains that say-on-frequency votes do not have to be in the form of a "resolution."
  - New Questions 169.05 and 169.06 — Address the wording that may be used in a proxy statement to describe the say-on-pay vote and the say-on-frequency vote, respectively.

- Regulation S-K, Item 402(t) — golden parachute compensation:
  - New Question 128B.01 — Clarifies which of a registrant's executives would be subject to Item 402(t) regarding the golden parachute vote and related disclosures.

Securities Offerings and Proxy-Related Items

In March 2011, C&DIs were issued addressing (1) topics in Regulation FD (in conjunction with exempt offerings) and (2) Rules 144(d), 144(h), 430B, and 433. In addition, the SEC issued new Regulation S-K C&DIs on proxy-related items, including the following:

- Section 116 — Item 401:
  - Question 116.08, which states that an entity incorporating by reference a proxy statement into its Form 10-K is required to disclose certain director information in Part 3 of Form 10-K even if it omits the same information from proxy filings because it is permitted to do so.
  - Question 116.09, which indicates that an entity must disclose information about a director's business experience when the director is appointed by preferred stockholders (in a manner similar to the information required when the board of directors nominates a director candidate).
- Section 118 — Item 402(b):
  - Question 118.07, which clarifies that a registrant is not required to discuss, in the compensation discussion and analysis (CD&A) section of a proxy statement, "executive compensation, including performance target levels, to be paid in the current year or in future years." However, the CD&A may need to address "actions regarding executive compensation that were taken after the registrant's last fiscal year's end" to the extent that such actions could "affect a fair understanding of the named executive officer's compensation for the last fiscal year."

Exchange Act Forms, Non-GAAP Financial Measures, and Proxy-Related Items

On July 8, 2011, the following C&DIs were issued on Exchange Act forms and non-GAAP financial measures:

- Exchange Act Form 12b-25, Question 107.02, which addresses when the filing of an issuer's Form 10-K may be considered timely.
- Exchange Act Form 8-K, Questions 121A.03 and 121A.04, which discuss disclosure of a number of broker nonvotes related to frequency of shareholder advisory votes on executive compensation and how frequently a registrant will include a shareholder advisory vote on executive compensation in its proxy.
- Non-GAAP Financial Measures, Question 108.01, which addresses CD&A and other proxy areas.

In addition, the Question 116.08 was withdrawn from the Regulation S-K C&DIs and others were added on proxy-related items, including the following:

- Item 401: Question 116.10, which addresses disclosures about directors whose terms would not continue after the annual shareholders' meeting.
- Item 402(b): Question 118.08, which clarifies that "Instruction 5 to Item 402(b) is limited to CD&A disclosure of target levels that are non-GAAP financial measures."
- Item 402(c): Question 119.28, which explains that the "grant date fair value for stock and option awards subject to performance conditions must be reported based on the probable outcome of the performance conditions as of the grant date."

On July 8, 2011, the SEC's Division of Corporation Finance also issued a statement with the C&DIs that outlines a framework for when a WKSI that has violated antifraud provisions may seek to obtain a waiver from the Division to retain its WKSI status.

Core Disclosure Project and Efforts to Improve Disclosures

The SEC has planned a "core disclosure" project to comprehensively review current disclosure requirements, modernize disclosures, and eliminate redundancy. At the 2010 AICPA Conference, representatives from the SEC acknowledged that further work on the core disclosures project has been deferred in light of the extensive rulemaking mandated by the Dodd-Frank Act. The SEC did emphasize, however, that completion of the project remains a staff goal.

Despite the project's deferral, the SEC staff continues to expect registrants to supply investors with comprehensive, transparent risk disclosures. For example, the staff continues to focus on credit and liquidity disclosures. In September 2010, the SEC issued two proposals on such disclosures: a proposed rule that would enhance disclosures about short-term borrowings and an interpretive release on liquidity and capital resource disclosure. Recently, the SEC staff has also focused on (1) the potential material effects of the events in Japan (the earthquake and tsunami on March 11, 2011), (2) enhancing disclosures about the risks related to loss contingencies, (3) expanding disclosures about cybersecurity related matters, and (4) enhancing disclosures about OTTI risk associated with investments that are in unrealized loss positions, including national sovereign debt. In addition, the staff has requested enhanced disclosures in the financial statements and in the Risk Factors, MD&A, and Business sections of the registrant's filings. The staff's reviews have also targeted risks associated with foreign operations, such as political risk, currency risks, and business climate and taxation risks.

As one might expect, the SEC staff addressed a number of these topics at the 2011 AICPA Conference.[3] The staff continued to emphasize, however, that registrants should (1) simplify their communications with investors and (2) ensure that information disclosed in their filings with the SEC is consistent with disclosures in other communications, such as press releases or analysts' calls. The SEC staff reiterated disclosure simplification by urging registrants to prepare their disclosures for investors rather than to avoid potential staff comments. The staff discussed the importance of reducing disclosure "overload"; that is, the repetition of information within a filing. Common examples of such overload include (1) disclosure of immaterial items (including the immaterial impacts of new accounting pronouncements), (2) disclosures added to address previous staff comments that continue to be carried forward, and (3) redundant disclosures included in numerous places within a periodic filing (e.g., information about loss contingencies).

In addition, the SEC staff informed conference participants that the Division of Corporation Finance began issuing new disclosure guidance in the form of Corporation Finance Disclosure Guidance (CFDG) topics. The SEC staff stated that in the future, it may issue CFDG in lieu of staff bulletins and "Dear CFO" letters. For example, the staff has issued CFDG Topic No. 2, "Cybersecurity," and CFDG Topic No. 4, "European Sovereign Debt Exposures." For additional information about these and other SEC related reporting matters, see Deloitte's 2011 *Heads Up* on the AICPA Conference.

International Financial Reporting Standards

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

[3] At the annual AICPA National Conference on Current SEC and PCAOB Developments (the "AICPA Conference") each December, regulators and standard setters give preparers updates on recent accounting, auditing, and SEC rules as well as a look inside their areas of focus for the reporting season ahead. Each year, Deloitte prepares a comprehensive Heads Up newsletter covering remarks made at the conference, which is available at www.deloitte.com/us/headsup.

Highlights of CAQ SEC Regulations Committee Meetings With the SEC Staff

The Center for Audit Quality (CAQ) SEC Regulations Committee meets periodically with the SEC staff to discuss emerging technical accounting and reporting issues related to SEC rules and regulations. Highlights from recent meetings are outlined below.

March 2011 Meeting

Highlights of the March meeting included:

- Current financial reporting matters:
    - Issues related to Japan's natural disaster.
    - Loss contingency disclosures.
    - ICFR considerations to support U.S. GAAP expertise for domestic companies with a majority of operations outside the United States.
    - IFRS work plan — SEC's analysis of IFRS application.
- XBRL implementation issues.
- Recent updates to the SEC Financial Reporting Manual (FRM).
- Current practice issues:
    - Transition issues related to pending accounting standards (e.g., those on leases, revenue recognition, financial instruments, and troubled debt restructuring).
    - Measuring the significance of an acquired equity method investment that will be accounted for under the fair value option.
    - Age of financial statements required for an acquired foreign business.
    - Calculating the significance of a business that is contributed to a joint venture.
    - Determining whether a parent has independent assets or operations under Regulation S-X, Rule 3-10(h)(5).
    - Reflecting in pro forma income statements the costs of being a public company.

June 2011 Meeting

Highlights of the June meeting included:

- Current financial reporting matters:
    - Implication of the SEC staff's "notification of completion" in Exchange Act filing reviews.
    - Loss contingency disclosure considerations.
    - Definition of "full and unconditional" related to guaranteed securities under Regulation S-X, Rule 3-10.
    - Reverse mergers.
    - Study of IFRS application.
    - Non-GAAP financial measures.

- XBRL matters.
- SEC staff's FRM update.
- Current practice issues:
    - Reporting requirements for acquisitions and dispositions made by a consolidated variable interest entity (VIE).
    - Significance test and Form 8-K reporting considerations related to consolidation of a VIE.
    - Disclosures about auditor changes within an international network — Regulation S-K, Item 304.
    - Audit and reporting considerations related to subsidiary guarantor financial statements — Regulation S-X, Rule 3-10(g).
    - Since the above-mentioned meetings, the SEC staff has taken action on a number of these issues, including revising the FRM, issuing C&DIs, and making several announcements.

September 2011 Meeting

Highlights of the September meeting included:

- Current financial reporting matters:
    - Loss contingency disclosure considerations.
    - MD&A disclosure considerations on foreign operating results and income taxes.
    - Definition of "full and unconditional" related to guaranteed securities under Regulation S-X, Rule 3-10.
    - Feedback on the SEC's (1) staff paper on incorporation of IFRSs and (2) request for comment on a process to retrospectively review existing regulations.
    - Management's responsibilities for validating third-party pricing service quotes on Level 2 assets and liabilities.
- XBRL-related matters.
- SEC staff review and other initiatives:
    - SEC staff's plan to review prospectus supplements of effective registration statements.
    - Distribution of comment letters to registrants by e-mail.
    - Staff's recent communication initiatives on reverse merger matters.
- Current practice issues:
    - Restatement disclosures considerations in IPO registration statements.
    - Retrospective application of ASU 2011-05 in connection with filing a new registration statement.
    - Foreign private issuer reconciliation considerations in Form 20-F.
    - XBRL requirements for (1) registration statements and (2) retrospectively revised financial statements on Form 8-K.
    - Financial statement requirements related to an acquisition of non-controlling interests in a consolidated subsidiary.

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 FRM is updated periodically. Recent FRM updates are discussed below.

October 2010 Update

The October 2010 release contains FRM updates as of June 30, 2010, which mainly consist of changes to guidance on Regulation S-X, Rule 3-09 (related to equity method investments); Rule 3-10 (related to guarantor considerations); and Rule 3-16 (related to registrants' issuances of securities collateralized by their affiliates' securities).

April 2011 Update

The April 2011 release contains FRM updates as of December 31, 2010. The updates address, among other things, changes and guidance clarification related to (1) combined periodic reporting; (2) the use of income averaging in the performance of the income test under Regulation S-X, Rule 3-05; (3) considerations under Regulation S-X, Rule 3-10, of "opt-out" clauses to determine full and unconditional guarantees and of both direct and indirect subsidiaries in the determination of "minor" subsidiaries; (4) changes in accountants; and (5) financial statements of foreign private issuers and foreign businesses.

July 2011 Update

The July 2011 release contains updates made as of March 31, 2011. The updates address, among other things, changes related to combined periodic reporting, audit requirements for recently acquired guarantor subsidiaries, and reporting considerations in reverse acquisitions and capitalizations.

September 2011 Update

The September 2011 release includes revisions that are stylistic only and affect the table of contents and Topic 1. FRM references related to affected areas have also been updated. The changes are not considered substantive and are not marked with date tags (which are generally included in the quarterly updates).

October 2011 Update

The October 2011 release contains updates made as of June 30, 2011. The updates address, among other things, changes related to (1) ASU 2011-05, (2) requirements in proxy and registration statements (including continuous shelf offerings), (3) acquisition and disposition reporting requirements for variable interest entities, and (4) subsidiary guarantee release provisions.

Other SEC Matters

Some SEC activities related to disclosures about loss contingencies and short-term borrowing, EDGAR requirements, interactive data, and SAB 114 are summarized below.

SEC's Focus on Compliance With Loss Contingency Disclosures

The SEC has recently renewed its efforts to improve registrants' compliance with existing disclosure requirements under ASC 450-20 in connection with litigation contingencies. Before redeliberating its proposed ASU on disclosures about certain loss contingencies, the FASB will evaluate such compliance. Thus, certain aspects of loss contingency disclosures will be subject to heightened scrutiny this reporting season. For further information, See Deloitte's Financial Reporting Alert 11-1, *SEC's Focus on Compliance With Loss Contingency Disclosures*.

SEC Issues Interpretive Release to Enhance Short-Term Borrowing Disclosures

On September 17, 2010, the SEC issued a proposed rule and interpretive release on presenting liquidity and capital resources disclosures in MD&A. As the complexity and types of financing activities used by registrants increase, it becomes increasingly important that the disclosures in MD&A give investors meaningful information about a registrant's liquidity and funding risks. The interpretive release clarifies the SEC's guidance on liquidity, leverage ratios, and the table of contractual obligations. The guidance in the interpretive release became effective on September 28, 2010; however, the proposed rule has not yet been finalized.

CAQ Publishes Alert Reminding Auditors of EDGAR Signature Requirements

Early this year, the CAQ published Alert 2011-04 in response to a recent communication from the SEC staff to the CAQ SEC Regulations Committee. The alert reminds auditors (1) that registrants must include signed audit reports in EDGAR filings and (2) of additional requirements related to typed "signatures" in electronic submissions. The alert indicates that the "SEC staff believes that readers should be able to easily determine the name of the firm that audited the financial statements and therefore will request amendments for any filings that do not comply with the Commission's requirements."

XBRL Taxonomy Considerations

- *U.S. GAAP 2011 XBRL Taxonomy* — On March 1, 2011, the SEC adopted the 2011 U.S. GAAP taxonomy.
- *U.S. GAAP 2012 XBRL Taxonomy* — The SEC staff announced at the 2011 AICPA Conference that it expects that the 2012 version of the U.S. GAAP taxonomy will be approved by the SEC for use in early 2012 and that when the 2012 version is approved, the 2009 version will no longer be supported (i.e., XBRL/interactive data submissions that use the 2009 version of the taxonomy will no longer be accepted by the EDGAR system). Registrants still using the 2009 version of the U.S. GAAP taxonomy for their XBRL submissions will be affected by this change because they will be required to transition to one of the SEC-approved versions of the taxonomy after the 2012 U.S. GAAP taxonomy has been approved by the SEC. Registrants still will be able to use the 2009 U.S. GAAP taxonomy for their year-end 2011 Form 10-K filings.

SEC Staff Releases Observations Resulting From Review of XBRL Submissions

On December 13, 2011, the staff in the SEC's Division of Risk, Strategy, and Financial Innovation published "Staff Observations From the Review of Interactive Data Financial Statements," which summarizes its review of interactive data file (XBRL) submissions received during the second quarter of 2011. The review included (1) the first submissions of the third group phased-in under the SEC's interactive data rules and (2) the first detailed-tagged submissions of the second phase-in group.

Although the staff noted that "[o]verall, the filings continue to indicate that filers are devoting significant effort to understand their responsibilities under this program, comply with the new rules and provide high-quality submissions," it still continues to identify a number of areas for improvement, many of which have been indicated in previous communications, including the staff's earlier observations published on June 15, 2011.

Observations regarding the following topics were recurring: (1) format of the statements, (2) negative values, (3) extended elements, and (4) completeness of tagging. The staff also provided a new observation related to the interactive data requirements for registration statements:

> Filers that are subject to the interactive data requirements must include XBRL with certain registration statements filed under the Securities Act of 1933 that physically, rather than through incorporation by reference, include financial statements once the registration statement contains a price or price range.

Registrants that fail to comply with this requirement will temporarily lose their short-form eligibility until the required interactive data files are both submitted to the SEC and posted to their corporate Web site (if any).

While these communications are not SEC rules, regulations, or statements, the staffs encourage registrants to "prepare future filings that are consistent with the themes of our observations."

In addition, the staff in the SEC's Office of Interactive Disclosure recently updated its "Staff Interpretations and FAQs Related to Interactive Data Disclosure," which address questions about some of the more technical aspects of such disclosure requirements.

SEC Issues SAB 114

On March 7, 2011, the SEC's Office of the Chief Accountant and its Division of Corporation Finance issued SAB 114. The SAB is intended to harmonize interpretive guidance in the codified SABs with current authoritative accounting guidance in the *FASB Accounting Standards Codification*. While certain portions of the codified SABs were revised or rescinded, the main changes represent updates to "accounting guidance references and other conforming changes to ensure consistency of referencing throughout the SAB Series."

SEC Staff Comment Examples

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

Many of the SEC staff's comments are related to loss contingencies and foreign income taxes. Comments have included include the following:

- *Loss contingencies (ASC 450)* — The SEC staff routinely comments when there is a reasonable possibility that realized losses would exceed the amounts accrued and when registrants either (1) do not disclose an estimate for a possible loss or range of loss or (2) state that such an estimate could not be reasonably made. When a registrant has asserted that it is not reasonably possible to estimate the possible loss or range of loss, the staff has raised questions about the procedures the registrant has in place to attempt to make an estimate. The staff will also question the timing of the recognition of a loss contingency. Registrants are expected to enhance their disclosures about loss contingencies as they obtain additional information. The staff has noted that it would not expect a registrant to state in one period that it was not reasonably possible to make an estimate and then recognize an accrual in the immediate subsequent period.
- *Foreign income taxes* — The SEC staff typically comments on the tax effect of earnings that are permanently reinvested overseas and on how a company's liquidity is affected. The staff asks for enhanced MD&A disclosures that (1) include the total amount of consolidated cash that was held by foreign subsidiaries when an assertion has been made that the earnings are permanently reinvested and (2) indicate that this cash is not available for use domestically without the registrant's incurring a tax liability. In addition, the SEC staff requests disaggregated information on earnings from foreign and domestic jurisdictions, particularly when there is a low effective tax rate because taxable earnings are generated in foreign countries whose statutory tax rate is lower than the U.S. rate. The staff also comments about the sustainability of the effective tax rate, particularly when the foreign country is experiencing an economic downturn.

The SEC staff also routinely comments on matters related to financial statement measurement, disclosure, and presentation. Topics of comment that may be of interest to companies in the oil and gas and the P&U sectors include the following:

- Oil and gas:
  - New oil and gas reporting requirements.
  - Proved undeveloped reserves.

    - Proved reserves impairment testing.
    - Significant changes in reserves and standardized measures.
    - Unproved property costs.
    - Environmental liabilities and risk.
    - Nonmonetary exchanges.
- P&U:
    - Subsidiary and equity investee dividend restrictions and the Schedule I requirement.
    - Accounting for the impact of rate-making.
    - Pension and postretirement plans.

For additional information about SEC comment letters, see Deloitte's SEC Comment Letters — Including Industry Insights: Improving Transparency (November 2011, Fifth Edition)

Section 3
International Financial Reporting Standards

IFRSs remain on the minds of many P&U sector companies as the SEC continues its efforts on its work plan for considering whether to mandate the standards for U.S. companies (see below) and as the FASB and IASB continue their accounting convergence efforts.

SEC Update

In November 2008, the SEC issued a proposed IFRS roadmap[4] outlining milestones that could potentially lead to mandatory transition to IFRSs in the United States and seeking 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. In February 2010, the SEC expressed its strong commitment to developing a single set of high-quality globally accepted accounting standards and affirmed that IFRSs are best positioned to be that set of standards for the U.S. market. The SEC directed its staff to execute a "work plan" that would address specific concerns highlighted in comment letters on the roadmap and that would allow the SEC to make a well-informed decision in 2011 about the use of IFRSs in the United States.

At the 2010 AICPA Conference, SEC Deputy Chief Accountant Paul Beswick introduced an approach to incorporating IFRSs in the United States that would combine an endorsement approach with a convergence approach. In May 2011, the SEC staff published a paper[5] in which it described the condorsement approach in more detail and sought feedback on it individually and by comparison to other possible approaches that have been previously explored (e.g., mandatory adoption of IFRSs, without an endorsement mechanism, on a specified date or after a staged transition over several years, coupled with (or without) an option for U.S. issuers to apply IFRSs early).

The condorsement approach would entail a transition phase during which the FASB would more closely align U.S. GAAP with IFRSs by addressing and evaluating differences between the two sets of standards and incorporating IFRSs into U.S. GAAP, with a focus on minimizing transition costs. While the term "U.S. GAAP" would be retained, the SEC staff envisages that at the end of the transition period, a "U.S. issuer compliant with U.S. GAAP should also be able to represent that it is compliant with IFRSs as issued by the IASB." Although the staff paper does not define the transition period, it cites examples of five to seven years or five years or more into the future.

After transition, the SEC and FASB would follow an endorsement approach (similar to the endorsement approaches adopted in other jurisdictions, such as the European Union and Australia) under which future IFRSs would be incorporated into U.S. GAAP via a specific process that would involve the application of specified endorsement criteria. Under the endorsement approach, the FASB and SEC would retain the ability to modify or supplement IFRSs if any of these modifications or supplements were in the public interest or necessary for the protection of U.S. investors. However, the staff paper notes that the goal is for IFRSs and U.S. GAAP to be consistent and to avoid having a U.S. "flavor" of IFRSs. Accordingly, the circumstances under which the FASB would consider modifying IFRSs should be similar to those under which the SEC would consider modifying U.S. GAAP (e.g., through Staff Accounting Bulletins). That is, the SEC staff expects such situations to be "rare and generally avoidable."

On July 7, 2011, the SEC held roundtable discussions with investors and representatives from smaller public companies and regulators (including the Federal Energy Regulatory Commission (the FERC)) to discuss benefits and challenges related to potentially incorporating IFRSs into the U.S. financial reporting system. The discussions touched on many topics in the SEC's staff paper. The investor panel strongly supported a single set of high-quality, globally accepted accounting standards and agreed that having a "single global language" would significantly benefit investors.

Concerns were raised regarding the uniform application of principles-based accounting standards and the IASB's interpretive mechanisms. Some panelists suggested, however, that uniform application of IFRSs around the world should not be a precondition for incorporating IFRSs into the U.S. financial reporting system. They noted that a global financial reporting language based on IFRSs is better than multiple financial reporting languages (i.e., retaining both U.S. GAAP and IFRSs)

4 SEC Proposed Rule Release No. 33-8982, *Roadmap for the Potential Use of Financial Statements Prepared in Accordance With International Financial Reporting Standards by U.S. Issuers.*

5 *Work Plan for the Consideration of Incorporating International Financial Reporting Standards Into the Financial Reporting System for U.S. Issuers — Exploring a Possible Method of Incorporation,* published on May 26, 2011.

even if that global financial reporting language has regional dialects. Some investors stressed the importance of the IASB's having a responsive interpretative mechanism subject to a formal standard-setting process because they noted that local interpretations of IFRSs could lead to a diverse application of IFRSs globally. Some suggested that the FASB provide interpretations of IFRSs if the IASB or its interpretative body, the IFRS Interpretations Committee, decides not to provide interpretations on important issues. In addition, some investors noted that interpretations by certain regulators (e.g., the PCAOB and SEC) could lead to a diverse application of IFRSs. Investors also indicated that they preferred retrospective application of IFRSs. Panelists representing smaller public companies expressed concern about the lack of resources and the potential implementation costs and had significant concerns with an implementation approach that would prolong implementation of IFRSs (staggered approach). Most supported a "big bang approach" if mandated in a realistic time frame. A staggered transition was perceived as more costly.

On November 16, 2011, the SEC staff published two papers:

- *A Comparison of U.S. GAAP and IFRS* — The SEC staff reviewed 29 U.S. GAAP Accounting Standards Codification (ASC) topics and compared them with corresponding guidance in IFRSs, as applicable, focusing on the more significant differences between the two sets of standards.

- *An Analysis of IFRS in Practice* — The SEC staff analyzed a selection of annual IFRS consolidated financial statements of both SEC registrants and nonregistrants. The staff also identified topics frequently commented on by the SEC's Division of Corporation Finance in its reviews of the SEC filings of foreign private issuers that prepare their financial statements in accordance with IFRSs.

In comparing U.S. GAAP and IFRSs, the staff focused on identifying differences because similar requirements under the two sets of standards were presumed to be "of sufficiently high quality." One fundamental difference noted was that IFRSs contain "broad principles to account for transactions across industries, with limited specific guidance and stated exceptions to the general guidance," whereas U.S. GAAP requirements are often more detailed and specific. Thus, many of the standards' differences are related to industry or transaction-specific guidance that is contained in U.S. GAAP but not in IFRSs. The staff noted that the existence of specific guidance under U.S. GAAP may contribute to consistency in application within a particular industry but not always across industries, whereas the reliance on broad principles under IFRSs may help promote broader consistency across industries.

The staff also highlighted fundamental differences in the boards' conceptual frameworks — in particular, the level of authority of the two frameworks and the definitions and recognition criteria for assets and liabilities. The staff suggested that unlike that of the FASB, the IASB's conceptual framework consists of authoritative guidance that applies in the absence of any specific standard or interpretation.

In its analysis of IFRS in practice, the staff found that financial statements of the companies included in the analysis "generally appeared to comply with IFRS requirements." However, they noted that the disclosures could be more transparent and clear. In particular, some companies did not provide relevant accounting policy disclosures or, when such disclosures were given, they were not sufficiently detailed or clear (e.g., disclosures about the nature of significant company transactions). Some companies also used terms that were "inconsistent with the terminology in the applicable [IFRSs]." The staff noted that in certain cases, "the disclosures (or lack thereof) also raised questions as to whether the company's accounting complied with [IFRSs]."

In addition, the staff found that diversity in the application of IFRSs diminished comparability of financial statements across countries and industries. The staff suggested this diversity is due to a variety of factors, such as explicit options permitted by IFRSs, the lack of guidance in some areas, and noncompliance with IFRSs.

As part of its analysis, the SEC staff also provided a summary of topics that the staff has focused on in its reviews of the most recent SEC filings of 140 foreign private issuers that prepare their financial statements in accordance with IFRSs as issued by the IASB. The topics commented on most frequently, as measured by the percentage of IFRS registrants that received comments, were financial instruments (nearly 70%) and financial statement presentation (about 50%).

While the SEC has yet to make a decision about whether, and, if so, when and how to incorporate IFRSs into the financial reporting system for U.S. issuers, the staff papers issued in 2011 marked another step toward the use of IFRSs and demonstrates the SEC's commitment to moving forward with IFRSs for U.S. issuers. In a speech made at the 2011 AICPA Conference, James L. Kroeker, SEC chief accountant, discussed the timing of a final report to be issued by the SEC staff on the incorporation of IFRS for U.S. issuers, noting that the SEC had hoped to make a determination as soon as 2011, but the final report will be delayed by a "few additional months."

The Modified Convergence Strategy

Convergence of U.S. GAAP and IFRSs remains a key goal of the FASB and IASB. In April 2011, the FASB and IASB gave an update on their convergence agenda. The boards noted that for a number of joint projects, including fair value measurement and other comprehensive income, they would be issuing final, substantially converged standards in the next few weeks. The boards also indicated that other joint projects for which they had previously committed to issuing final standards (financial instruments, revenue recognition, and leases) or an exposure draft (ED) (insurance) by June 2011 would require further work and consultation with constituents; therefore, they decided to delay the timing of these projects to the second half of 2011. The boards have since further revised the timing of these convergence projects as well as the types of due process documents they previously intended to issue

The IASB released an updated work plan in December 2011 incorporating the impacts of recently issued pronouncements and outlining revised current best estimates for its various projects. A number of projects have been deferred and the expected timing of other projects more precisely defined. Deadlines for finalization of IFRSs on leases and revenue recognition projects are now not explicitly stated within the timeframes outlined (and are therefore not expected before the end of 2012). After redeliberations of the issues identified in the comment letter process, the boards jointly issued their revised ED on revenue recognition in November 2011 (comment letters are due by March 13, 2012) and the reexposure of the lease standard is now expected in the second quarter of 2012.

With respect to the IASB's financial instruments projects, in November 2011, the IASB tentatively decided to reopen IFRS 9 to address potential application issues in IFRS 9 and 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. In December 2011, the IASB 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 of the delay in the expected timing of completion of the remaining phases of the financial instruments project. The IASB intends to allow entities to apply all phases of the financial instruments project concurrently. Before the amendments, IFRS 9 was mandatorily effective for annual periods beginning on or after January 1, 2013. A reexposure on impairment is expected in the second quarter of 2012, while an ED on macro hedge accounting is expected in the third quarter of 2012 and a review draft of general hedge accounting requirements is now expected in the first quarter of 2012.

Section 7 of this publication highlights some of the potential changes to U.S. GAAP as a result of the FASB's and IASB's convergence efforts and that may be of interest to P&U companies. However, those changes to U.S. GAAP may not necessarily mean that U.S. GAAP would be converged with IFRSs. The following summary lists some of the convergence projects in which the boards have not been successful (yet) in reconciling their divergent views on all aspects faced in these projects:

- *Revenue recognition* — Certain rate-regulated entities participate in alternative revenue programs and follow the guidance under U.S. GAAP in ASC 980-605 on regulated operations. The FASB tentatively decided to (1) retain the existing requirements for alternative revenue programs currently within the scope of ASC 980-605 (which the FASB previously identified would be superseded under the revenue recognition ED) and (2) require that revenues from these alternative revenue programs be presented separately from rate-regulated revenues (which would be within the scope of the revenue project). In addition, the FASB identified the guidance in ASC 980 as a potential topic for future convergence standard setting with the IASB.

- *Fair value measurements* — In May 2011, the FASB issued ASU 2011-04. The ASU is the result of joint efforts by the FASB and IASB to develop a single, converged fair value framework. However, there are differences between the ASU and its international counterpart, IFRS 13. In particular:
    - Amounts disclosed in Level 3 of the fair value hierarchy under IFRSs may differ from those disclosed under U.S. GAAP because the offsetting requirements for financial instruments differ.
    - Quantitative measurement uncertainty analysis is required under IFRSs for financial instruments measured at fair value and categorized in Level 3 of the fair value hierarchy.
- *Financial instruments: hedge accounting* — The hedge accounting models that the FASB and IASB have been developing (separately) are different in many important aspects. See the Financial Instruments section below for further details on the IASB's proposed model.
- *Financial instruments: classification and measurement* — Both IFRS 9 and the FASB's new classification and measurement model require entities to classify financial assets on the basis of the entity's business strategy for these assets and the assets' contractual characteristics; however, the definitions of, and criteria for, the business strategy and contractual characteristics are different under IFRS 9 and the FASB model. Some possible impacts include the following:
    - The application of IFRS 9 may result in entities' measuring debt securities, such as U.S. treasuries, at amortized cost; however, the FASB's model is not likely to allow entities to measure these securities at amortized cost but would rather require them to measure the securities at fair value through net income or through other comprehensive income.
    - The FASB's model would generally require entities to measure equity securities at fair value through net income; however, IFRS 9 gives entities an irrevocable option to measure these securities at fair value through other comprehensive income. Also, IFRS 9 prohibits entities from reclassifying any unrealized gains or losses from other comprehensive income to net income upon sale or settlement of an equity security that is measured at fair value through other comprehensive income. The FASB's model does not have a similar prohibition against financial assets being measured at fair value through other comprehensive income (e.g., certain debt securities).
    - The FASB's model would require entities to separate embedded derivatives that are not closely related from hybrid financial assets; IFRS 9 does not.
    - The FASB model does not allow reclassifications of financial assets from one measurement category to another if the business strategy for these assets changes. IFRS 9 specifically requires such reclassifications in these circumstances.
    - IFRS 9 has an option to measure financial assets at fair value through net income to mitigate a measurement mismatch between those assets and related financial liabilities. The FASB's model would not provide a similar option. Also, IFRS 9 requires entities to present, in other comprehensive income, changes in the fair value of financial liabilities designated to be measured at fair value through net income under the fair value option that are attributable to the entities' own credit. The FASB's model would not include a similar presentation requirement.
    - Differences in the recognition of day 1 gains or losses that arise when the initial fair value of an asset or a liability measured at fair value differs from its transaction price. Under IFRS 9 and IAS 39, entities are prohibited from recognizing this difference as a day 1 gain or loss if they use a valuation technique to determine the asset's or liability's fair value and that technique does not solely use observable data. There is no similar prohibition under U.S. GAAP.

- *Financial instruments: asset and liability offsetting* — In December 2011, the FASB issued ASU 2011-11, which finalized the proposals outlined in the Board's January 2011 ED on balance sheet offsetting of financial assets and liabilities. The IASB made amendments to IFRS 7 that require essentially the same disclosures as those required by ASU 2011-11 and also clarified certain aspects of IAS 32. The FASB's issuance of this ASU represents the culmination of its joint offsetting project with the IASB, which had the original objective of converging the U.S. GAAP and IFRS offsetting models. However, since the boards could not agree on a single converged offsetting presentation model, they ultimately voted to retain their existing offsetting models. Nonetheless, given (1) constituents' desire for convergence and improved comparability and (2) a general agreement that both gross and net information was useful for investors and other financial statement users, the FASB and IASB found some common ground in developing new, expanded disclosure requirements. Section 7 of this publication highlights some of these requirements under U.S. GAAP.

Key Potential Impacts of IFRS Adoption

IFRSs present particular technical accounting challenges to P&U sector companies, as discussed below.

Regulatory Assets and Liabilities

IFRSs do not presently provide specific guidance on regulatory assets and liabilities or on the recognition of revenues and expenses covered by future increases and decreases in regulated tariffs. However, on July 23, 2009, the IASB issued an ED of a proposed standard on rate-regulated activities (RRAs). In contrast to ASC 980, this ED requires:

- That a probability-weighted cash flow approach be used to initially measure and record regulatory assets and liabilities in each subsequent reporting period on the basis of the expected present value as opposed to their being recognized in their entirety if recovery is probable.
- That an impairment evaluation be performed in accordance with IAS 36 when it is reasonable to assume that sufficient revenues cannot be collected to recover the entity's costs. (Under U.S. GAAP, inability to collect sufficient revenues to cover an entity's costs and earn a reasonable return is a matter of scope that would require the utility to cease regulatory accounting.)
- More extensive disclosures than those currently required by U.S. GAAP, including a tabular reconciliation of each category of regulatory asset or liability from the beginning of the period to the end.

During the first half of 2010, the IASB staff conducted additional research and analysis on the key issue of the recognition of regulatory assets and liabilities. At the IASB's July and September 2010 meetings, the staff reported that the results of the additional research and analysis had not provided a clear direction for the project. Furthermore, in the staff's opinion, (1) regulatory assets did not meet the requirements for separate recognition as specified in IAS 38 and (2) regulatory liabilities did not meet the definition of a provision in IAS 37 or the definition of financial assets or liabilities. In accordance with the staff's recommendations, the Board considered whether to finalize the project by issuing a final standard that confirms that IFRSs do not permit the recognition of regulatory assets or liabilities and require specific disclosures about the impact of regulations on an entity's activities. The Board further considered a proposal to incorporate into future comprehensive projects, either as part of the conceptual framework project or as part of a review of the accounting for intangible assets, the issue of how the effects of rate regulation should be accounted for. It was observed that RRAs clearly are a difficult area and that it was possible to make a case in any direction. Several Board members noted that further analysis was required related to the broader question of accounting for intangible assets.

The IASB Chairman summarized the discussion, observing that the Board was split and that there were a number of considerations that could be added to the staff's analysis. The Chairman was adamant that the Board could not continue doing further analysis on the matter indefinitely and suggested that the Board consider the following alternatives:

- A disclosure-only standard on RRAs.

- An interim standard (similar to IFRS 4 or IFRS 6) in which to grandfather previous GAAP accounting practices with some limited improvements.
- A medium-term project to add to the post-2011 agenda, focused only on the effects of rate regulation.
- A comprehensive project on the accounting for intangible assets.

The IASB did not decide on any alternative but rather chose to include in its public consultation on its future agenda a request for views on what form a future project might take, if any, to address RRAs. A revised timetable has not yet been announced by the IASB since the deferral of the project in September 2010.

Property, Plant, and Equipment

Asset Componentization

IAS 16 requires entities to identify any significant components of an item of PP&E and depreciate those components separately from the remainder of the item. However, if the significant components of an item of PP&E have the same useful lives and patterns of consumption, IAS 16 allows entities to group these components together in determining the depreciation charge.

The components approach in IAS 16 requires P&U entities to assess whether any of their power plants' components (e.g., turbine rotor, turbine blades, boiler, electronic equipment) are significant[6] and, if so, whether these components have different useful lives and patterns of consumption. If a power plant consisted of significant components with different useful lives and patterns of consumption, an entity would have to allocate the plant's total book value to these components and separately depreciate them.

Entities that currently depreciate plant assets over a single overall useful life (e.g., 20 or 30 years) may find the componentization requirements in IAS 16 to be a challenging process, especially if the PP&E ledger maintained for U.S. GAAP is not sufficiently detailed or lacks certain key data necessary to specifically identify components. This may be particularly true for old plants, for plants owned by joint ventures (on which data access may be limited), or for acquired assets for which legacy preacquisition data may be limited. Consequently, entities may need to involve plant managers and engineers to review the available asset data, including overhaul and replacement schedules, to complete the componentization process.

The following are other potentially significant effects of asset componentization:

- Under U.S. GAAP, the useful life of a unit can be an average service life for a group of assets. Under group depreciation methods, when an asset is retired, the resulting gain or loss is not recognized. Instead, accumulated depreciation is charged. Further depreciation charges will reflect the embedded gain or loss.
- Under IFRSs, the cost of planned major maintenance activities is most likely recognized as an asset separately from the related power plant, whereas under U.S. GAAP these costs would often be expensed as incurred or deferred and amortized. For example, upon acquisition of a power plant, an entity would need to identify the estimated cost of major maintenance or overhaul scheduled to be performed every so often (e.g., five years). If the recognition criteria in IAS 16[7] are met and the estimated cost is significant and has a different useful life and pattern of consumption than the remainder of the plant, the entity would recognize the cost as a separate component and depreciate it separately. When the entity performed a major maintenance, it would derecognize any remaining carrying amount of that component and recognize the cost of the major maintenance just performed as a new component.

[6] The determination of whether the cost of a part of an item of PP&E is significant requires a careful assessment of the facts and circumstances. This assessment, at a minimum, would include (1) comparing the cost allocated to the component to the total cost of the PP&E and (2) determining how componentizing and not componentizing affect depreciation expense differently.

[7] IAS 16.7 permits the recognition of the cost of an item of PP&E as an asset only if "(a) it is probable that future economic benefits associated with the item will flow to the entity; and (b) the cost of the item can be measured reliably,"

Revaluation Option

IFRSs allow entities to make an accounting policy election to measure PP&E by using either a cost model or a revaluation model.[8] The cost model requires an entity to measure PP&E at cost less any accumulated depreciation and impairment losses and is thus similar to the historical cost measurement required for these types of assets in U.S. GAAP. The revaluation model is available only if the fair value of an item of PP&E is reliably measurable, and it requires an entity to carry PP&E at fair value as of the revaluation date less any subsequent accumulated depreciation and impairment losses. The entity would recognize an increase in the fair value as a result of a revaluation in other comprehensive income and accumulate it in equity as revaluation surplus unless the increase reverses a revaluation decrease of the same asset previously recognized in profit or loss, in which case the entity would recognize the increase in profit or loss. If a revaluation resulted in a decrease in the asset's carrying amount, an entity would recognize such decrease in other comprehensive income and charge it directly against any related revaluation surplus for the same asset and recognize any excess in profit or loss. When the revalued asset is disposed of, the revaluation surplus is not reclassified to profit or loss but remains in equity (but may involve a transfer within equity between accumulated other comprehensive income and retained earnings). The revaluation model requires entities to recognize depreciation expense on the revalued amount and would thus result in higher depreciation expense relative to the cost model if the fair values of PP&E increases.

Costs Eligible for Capitalization

IAS 16 requires capitalization of costs that are directly attributable to bringing an item of PP&E to working condition for its intended use. Directly attributable costs include certain directly related employee costs, site preparation costs, delivery costs, installation costs, and professional fees. Directly attributable costs exclude administrative and other general overhead costs, which may have historically been capitalized under regulatory accounting in U.S. GAAP. Regulatory items recorded with PP&E under U.S. GAAP, such as allowance for funds used during construction, also do not appear to comply with IAS 16 and may ultimately only be recognized under an IFRS standard on RRAs.

IFRS 1 Exemption — Use of Deemed Cost for Operations Subject to Rate Regulation

Paragraph D.8B of IFRS 1 permits entities that transition to IFRSs to use, as deemed cost, the carrying amount of an item of PP&E that is or was previously used in operations subject to rate regulation and that may include amounts that qualified for capitalization in accordance with the previous GAAP but not in accordance with IFRSs. If this exemption is elected, net book value under U.S. GAAP at transition would become gross book value under IFRSs, and accumulated depreciation under IFRSs would be reset to zero. Entities may apply this exemption to specific items and choose not to elect it for other items. However, prospectively, costs must comply with the IAS 16 guidance on capitalization to be included in PP&E.

Asset Impairments

There are two major differences between U.S. GAAP and IFRSs in the guidance on impairment of specific types of assets (e.g., PP&E):

- Under U.S. GAAP, entities are required to apply a two-step approach in determining whether they must recognize an impairment loss on these assets. First, an entity compares the carrying amount of the asset with the sum of the undiscounted future cash flows that the entity expects to derive from the asset. When the asset's carrying amount is higher than its undiscounted expected future cash flows, the asset is deemed impaired. The entity must then recognize an impairment loss equal to the excess of the asset's fair value over its carrying amount. In contrast, IFRSs require entities to compare the carrying amount of an asset with its recoverable amount (defined as the higher of the asset's value in use, which is based on discounted expected future cash flows, or fair value less costs to sell) and write down the asset to the recoverable amount if the carrying amount exceeds the recoverable amount. The ultimate effect is that IFRSs may result in earlier recognition of impairment losses on PP&E and certain other types of assets.

[8] An entity's accounting policy must be consistent for all assets within a particular asset class (IAS 16.29).

- Under U.S. GAAP, reversals of previously recognized impairment losses are generally prohibited (one exception is for utility companies with previously disallowed costs that are subsequently allowed by a regulator). In contrast, IFRSs require the reversal of a previously recognized impairment loss on an asset other than goodwill[9] when there is an indication that that impairment loss no longer exists or has decreased. In that case, entities must increase the asset's new carrying amount to its then-recoverable amount, except that the new carrying amount cannot be greater than what the carrying amount would have been had the entity never recognized any impairment losses in prior periods. As a result, the impairment guidance in IFRSs causes entities to track asset impairments, even after the initial write-down, to determine whether the impairment must be reversed. Furthermore entities must track the historical cost of assets and the related accumulated depreciation to determine the cap on the amount of any future reversals of previously recognized impairment losses.

There may also be differences in areas such as determination of the appropriate level of impairment (e.g., at the plant level or a system level).

Asset Retirement Obligations

Both IFRSs and U.S. GAAP prescribe that entities recognize an ARO liability[10] for the obligation to dismantle and remove PP&E from a site, and restore that site, and that they include the initial estimate of the ARO liability in the carrying amount of the related asset. While both accounting frameworks provide for a present value approach in measuring the ARO liability, the mechanics of each approach differ. Under U.S. GAAP, an entity must use its credit-adjusted risk-free rate of interest to discount the ARO liability, whereas IFRSs require the entity to apply a rate reflecting current market assessments of the time value of money and risks specific to the liability. Entities must carefully consider selection of the appropriate rate to measure the ARO liability in each case. Both accounting frameworks require entities, after initial recognition of the ARO liability, to review the liability as of each reporting date and adjust it to reflect current best estimates, which may include adjustments to the discount rate used to measure the liability. However, IFRSs prescribe the use of a current discount rate to remeasure the entire ARO liability. In contrast, under U.S. GAAP period-to-period revisions to either the timing or amount of the original estimate of undiscounted cash flows are treated as separate layers of the ARO liability. Entities use the current credit-adjusted risk-free rate to discount upward revisions and the original credit-adjusted risk-free rate to discount downward revisions.

IFRIC Interpretation 1 specifies the accounting for the effect of changes in the measurement of ARO liabilities as a result of a change in the timing or amount of cash flows or changes in discount rates. The accounting for these changes is significantly different depending on whether entities use the cost model or revaluation model for the related asset.

Inventory

IAS 2 requires the use of either the FIFO method or the weighted-average cost method to assign the cost of inventories. Further, IFRSs require that the same costing formula be used for all inventories with a similar nature and use to the entity. Most regulated gas distribution utilities have purchased gas adjustment (PGA) or similar clauses to recover gas costs, and several of these gas distribution utilities have for years used the LIFO method of accounting for gas inventories. During periods of rising prices, the LIFO costing method leads to higher costs of sales and, with PGA clauses, more timely rate recovery. However, LIFO is not a permitted method of inventory accounting under IFRSs.

In addition, a LIFO conformity requirement exists for tax purposes — a taxpayer may not use LIFO for tax purposes unless LIFO is also used for financial reporting purposes. Unless the tax law is changed, entities adopting IFRSs will need to revert to a non-LIFO method for tax purposes. The financial reporting effects of adopting IFRSs are charged or credited to retained earnings, but the cumulative effect of changing tax methods of accounting is recognized as taxable income ratably over a future period. As part of the PGA rates setting regulatory process, P&U sector companies will need to discuss with their regulatory commissions whether a change from LIFO will also occur and, if so, whether there will be a transition period. If the entity discontinues LIFO, although the price charged for gas will be reduced for a period to reflect the low-cost older LIFO layers, the entity's rate base may be increased to reflect more current (and potentially higher) costs of gas inventory. In

9 Like U.S. GAAP, IFRSs prohibit entities from reversing previously recognized impairment losses on goodwill.

10 Although IFRSs do not use the term "asset retirement obligation" or "ARO," the term ARO will be used to describe such decommissioning, restoration, and similar liabilities under both U.S. GAAP and IFRSs.

industries without PGA clauses, a change from the LIFO method generally accelerates the payment of taxes because lower cost of goods sold amounts are recognized for tax purposes while sales prices remain constant. In industries with a PGA clause and a required change from LIFO to FIFO, there may be a more adverse impact on cash flow because revenues will be lower to reflect the liquidation of LIFO layers for regulatory purposes while taxable income would be accelerated by the cumulative effect of the change in accounting method arising from the recapture of the LIFO reserve.

Lease Accounting

See Section 7 of this publication.

Income Taxes

A conversion to IFRSs will affect income taxes as a result of (1) the differences in the accounting for income taxes between IAS 12 and ASC 740 and (2) changes in pretax IFRS accounting differences that may have either current or deferred tax implications (e.g., changes in the accounting inventories, revenue recognition and lease accounting). Although the IASB plans to issue a limited scope amendment to IAS 12, the FASB has indefinitely postponed any convergence efforts on income taxes. A joint ED on income taxes was issued by the IASB and FASB on March 31, 2009; however, because the comment letters were highly critical, the IASB elected not to move forward with the issuance of a final standard. The limited-scope project is to provide guidance on certain issues, such as the accounting for uncertain tax positions and valuation allowances. The IASB will consider a more comprehensive project on income taxes over a longer timeline.

From a tax perspective, there are many areas affected by a potential conversion to IFRSs. The differences between the income tax accounting standards, ASC 740 and IAS 12, would be the most obvious area. Neither IAS 12 nor the ED on RRAs addresses issues pertaining to the regulatory treatment of income tax accounting such as flow-through accounting or deferrals of the effects of changes in tax law, including tax rates. These matters are addressed in U.S. GAAP on a coordinated basis in ASC 980-740. Further, entities will also find a lack of guidance on the treatment of investment tax credits (ITCs) and other tax incentives under IFRSs. While there is guidance under U.S. GAAP on a preferred method for the recognition of such benefits including ITCs, the accounting for ITCs is explicitly beyond the scope of IAS 12.

Apart from regulatory accounting and ITC, entities with material book expenses related to share-based compensation, uncertain tax positions, taxable intercompany transactions (before elimination in consolidation) and foreign currency translation adjustments related to nonmonetary assets would be the most likely to experience significant effective tax rate implications following a conversion to IFRSs.

In addition to the differences with respect to accounting for income taxes, there are many ways in which the tax function is affected by an IFRS conversion outside the tax provision. Affected areas include the impact on tax accounting methods, tax department operations, and global tax planning and treasury management. These areas are generally affected by pretax accounting differences between IFRSs and U.S. GAAP. As the FASB and the IASB continue to focus on the issuance of new accounting standards under a joint convergence process, public and private entities issuing financial statements under U.S GAAP should expect and be prepared for significant changes in pretax accounting income that could have tax repercussions apart from an actual move to IFRSs.

- *Tax accounting methods* — IFRS pretax accounting differences could result in an impact on the computation of federal and state taxable income as well as the calculation of deferred tax assets and liabilities. Entities need to assess the pretax differences between U.S. GAAP and IFRSs to determine whether the new IFRS methods of accounting are permissible methods for tax purposes. If the IFRS methods are permissible and desirable for tax purposes, entities need to (1) assess whether it is necessary to file requests for changes in tax accounting methods, some of which may require advance consent from the national office of the IRS and (2) determine how the cumulative effect of the changes are taken into account for tax purposes.

An example of an accounting convergence project that may have a significant impact on pretax accounting income and tax accounting methods is the lease accounting standard. For many companies, the classification of leases for tax purposes has historically followed the financial accounting treatment as either a capital or an operating lease. Under U.S. tax law, however, the classification of leases is generally based on economic factors established by case law and IRS administrative rulings. In implementing the new accounting standard, entities may want to adopt a process to document the appropriate tax classification of their lease arrangements, particularly for complex transactions, and evaluate potential multistate and foreign tax implications that may arise from the capitalization of leases for book purposes.

- *Tax department operations* — There may be many changes to an entity's existing chart of accounts that may affect the tax compliance process as well as the tax provision. Entities will need to evaluate any IFRS changes in their pretax accounting methods and systems to determine whether they affect tax provision and compliance software applications or otherwise affect tax data requirements. Further, training must be considered for tax personnel, and the extent of such training and its timing are important considerations.

- *Global tax planning and treasury management* — For those utility entities that have multinational operations, a change to IFRSs for local country statutory reporting could have a cash tax impact to the extent that the computation of taxable income is tied to the statutory accounts. For example, some jurisdictions impose thin capitalization rules that limit the amount of interest expense that is deductible by an entity with regard to related party debt. Those limits are often based on debt-to-equity ratios. IFRS conversion adjustments are likely to affect the balance sheet ratios and therefore may have an impact on allowable interest deductions. Other examples of areas that may be affected by a change to IFRSs on local country statutory books are transfer pricing and the determination of distributable reserves that are required to pay dividends in many jurisdictions.

Financial Instruments

The guidance under IFRSs and U.S. GAAP on accounting for financial instruments is conceptually similar; however, 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. In addition, there are certain exemptions under U.S. GAAP for legacy contracts that were executed before a particular date, such as exemptions on legacy-embedded derivatives. Since first-time adopters of IFRSs must adopt those standards retrospectively (with some limited exceptions), P&U sector companies may have long-term arrangements that they might have to reconsider for possible embedded derivatives.

The IASB and the FASB 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 two boards have adopted different strategies to advance their agenda. Unlike the FASB, which issued a comprehensive exposure draft of new classification and measurement, impairment and hedge accounting proposals in May 2010, the IASB decided to address 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 other comprehensive income, 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 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. In December 2011, the IASB 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.

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 is working on replacing the existing incurred loss model with an expected loss model that is more forward looking in nature 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 that the IASB has developed, either individually or together with the FASB, have so far not been received favorably by constituents. As a result, a new impairment model is still on the drawing board, with the next milestone most likely being another ED currently scheduled for release in the second quarter of 2012.

Derecognition

The IASB has completed this phase. Originally, the IASB’s goal was to improve the existing derecognition requirements for financial assets and liabilities in IFRSs, but later in the project the Board decided to retain those requirements. However, the IASB amended IFRS 7, expanding the disclosure requirements for transfers of financial assets that qualify for derecognition and for those that do not.

Offsetting

Currently, key differences between IFRS and U.S. GAAP are as follows:

- *Netting is not elective* — Under IFRSs, entities are required to set off financial assets and financial liabilities in the balance sheet when the criteria for setoff are met, while under U.S GAAP, offsetting is elective: entities are not required to set off financial assets and financial liabilities in the balance sheet even if the criteria for setoff are met.
- *Intent to set off* — Under IFRSs, to qualify for offsetting, there must be intent to settle on a net basis or to realize the asset and settle the liability simultaneously. There is no exception for assets and liabilities subject to master netting agreements. Under U.S. GAAP, an entity may elect to offset fair value amounts for certain assets and liabilities subject to master netting agreements even in the absence of an intention to set off.
- *Offsetting amounts due from a third-party debtor against the amount due to a creditor* — Under IFRSs, offsetting of an amount due from a third party against the amount due to a different creditor is permitted in "unusual" circumstances. Under U.S. GAAP, offsetting of an amount due from a third-party debtor against the amount due to a different creditor is not permitted.

After reaching differing tentative decisions on how to proceed with their joint exposure draft, as explained above, the IASB and FASB developed new, converged disclosure requirements to increase the comparability of financial statements prepared in accordance with U.S. GAAP and IFRSs. In December 2011, the FASB issued ASU 2011-11, which finalized the proposals outlined in the Board’s January 2011 ED on balance sheet offsetting of financial assets and liabilities, effective for periods beginning on or after January 1, 2013. On the same day the FASB issued ASU 2011-11, the IASB made similar amendments to IFRS 7 that require essentially the same disclosures as those required by ASU 2011-11. The IASB also clarified certain aspects of IAS 32 as follows:

- To indicate that a right of set-off should be legally enforceable both in the normal course of business and in the event of default, bankruptcy, or insolvency of one of the counterparties.
- To modify the definition of “net settlement” in IAS 32 to include gross settlement mechanisms with features (1) that eliminate or result in insignificant credit and liquidity risk and (2) under which processing of receivables and payables occurs in a single settlement process.

Hedge Accounting

The IASB has developed a new general hedge accounting model that would be more principles-based than the existing hedge accounting model in IFRSs and would align hedge accounting with an entity's risk management. The IASB staff plans to publish a review draft of general hedge accounting requirements in the first quarter of 2012. The IASB is also working on a new macro hedge accounting model and is expected to publish an ED of proposals of that model in the third quarter of 2012.

The IASB's new general hedge accounting model is different from the existing IFRS model in some key areas:

- *Hedge effectiveness assessment* — The new IASB model does not contain a numerical threshold, such as the 80-125 percent band, for when a hedging relationship would be considered effective and eligible, or continue to be eligible, for hedge accounting. It also does not require a retrospective assessment of hedge effectiveness. Instead, entities would prospectively assess whether the hedging relationship involves an economic relationship between the hedged item and hedging instrument in which the effect of credit risk does not dominate the value changes from that relationship.

- *Voluntary dedesignation of a hedging relationship* — The new IASB model prohibits entities to voluntarily discontinue a hedging relationship when the risk management objective for the hedge remains the same and all other qualifying criteria are still met.

- *Mandatory rebalancing* — The new model requires entities to rebalance (i.e., adjust the quantities of the hedged item or the hedging instrument in) a hedging relationship if the hedge ratio used for risk management purposes changes or if rebalancing is required to prevent the hedge ratio resulting in an imbalance that would create hedge ineffectiveness in order to achieve an outcome that is inconsistent with the purpose of hedge accounting. In effect that means that if for risk management purposes an entity adjusts the hedge ratio in response to changes in the economic relationship between the hedged item and the hedging instrument, the hedging relationship will automatically be adjusted accordingly (provided that it would not result in an imbalance). For example, consider a cash flow hedge of a highly probable forecast purchase of 100 units of a commodity. If during the hedging relationship the entity's purchase requirements change such that now only 90 units are highly probable, the hedging relationship in respect of the 10 units is no longer eligible for hedge accounting. To accommodate this change, hedge accounting for 10 units of the hedged item is (mandatorily) discontinued while the remaining 90 units continue to be designated with no change.

- *Hedging risk components of nonfinancial items* — The new IASB model removes the prohibition in existing IFRSs against hedging risk components of non-financial items other than foreign currency risks and provides that risk components of non-financial items are eligible hedged items if they are separately identifiable and reliably measurable.

- *Hedge accounting for net positions* — The new model permits groups of individually eligible hedged items to be hedged collectively as a group, provided the group of items is managed together for risk management purposes. Such groups may be net positions (i.e., items with offsetting fair values or cash flows). However, in July 2011, the IASB clarified the Board's tentative decision that cash flow hedges of net positions would only be available for hedges of foreign currency risk.

- *"Basis adjustments"* — Such adjustments would be mandatory when a forecasted transaction in a cash flow hedge results in the recognition of a nonfinancial asset or a nonfinancial liability. Currently an entity may either (1) adjust the initial carrying amount of the hedged item for the gain or loss on the hedging instrument, or (2) leave the gain or loss on the hedging instrument within other comprehensive income (OCI) until the hedged item impacts profit and loss when it is then recycled from OCI to profit and loss. The current accounting policy choice results in various comparability issues including the following: (1) a basis adjustment approach is not available for financial assets, (2) under U.S. GAAP basis adjustments are precluded, and (3) the two elections result in different carrying amounts for the recognized nonfinancial asset and, although they do not result in different amounts recognized within profit and loss, they are recognized within OCI.

- *Hedging with financial options and forward contracts* — When an entity excludes the change in the time value of a financial option and only includes its intrinsic value in the designation of that option as a hedging instrument, the new IASB model requires entities to defer some or all of the change in the fair value of the time value component in other comprehensive income and to later reclassify these amounts in other comprehensive income to profit or loss or to the basis of the hedged item, depending on whether the hedged item is transaction-related or period-related. Similarly, the model permits entities that designate only the spot element of a forward contract as the hedging instrument to recognize the forward points that exist at inception of the hedging relationship in profit or loss over time on a rational basis and to accumulate subsequent fair value changes in accumulated other comprehensive income.

- *"Own-use" scope exception* — As part of developing the new general hedge accounting model, the IASB decided to propose to extend the fair value option in IFRS 9 to contracts that meet the 'own use' scope exception if doing so eliminates or significantly reduces an accounting mismatch.

See Section 7 of this publication for further details on convergence activities related to classification and measurement, and impairment of financial instruments.

Joint Ventures

Under U.S. GAAP, a venturer is not required to conform a joint venture's accounting policies to those of the venturer in the venturer's consolidated financial statements. However, IFRSs require a venturer to make adjustments to conform a jointly controlled entity's accounting policies to those of the venturer when applying the equity method of accounting. Complying with this requirement may be complex, particularly with respect to inventory costing methods, and companies are likely to have to gather more data from equity method investments when reporting under IFRSs.

Initial Adoption

IFRSs require one year of comparative financial information to be reported under IFRSs on the basis of the rules in effect as of the reporting date. For example, an entity with a December 31, 2010, reporting date would be required under IFRSs to also provide comparative financial statements in compliance with IFRSs for 2009 by using those standards effective as of December 31, 2010. This one-year requirement differs from the SEC's proposed roadmap, which would require entities to provide two comparative years (in addition to the year of adoption) of statements of comprehensive income, cash flows, and equity. This is one of the areas that many entities addressed in their comments on the roadmap, noting that the SEC allowed foreign private issuers to include only one year of comparative information in their initial IFRS financial statements. Thus, the SEC may consider a similar accommodation for domestic registrants if it decided to incorporate IFRSs into U.S. GAAP.

With some limited exceptions, some of which are explained below, IFRS 1 generally requires entities to apply IFRSs retrospectively and to recognize all assets and liabilities in accordance with IFRSs and derecognize any assets and liabilities that qualified under legacy GAAP rules (U.S. GAAP) but do not qualify for recognition under IFRSs. IFRS 1 provides that first-time IFRS adopters recognize any differences resulting from the change in accounting policies from the previously applied GAAP to IFRSs directly in retained earnings.

Key adoption differences or optional exemptions specific to P&U sector companies include the following:

- Upon adoption of IFRSs, an entity may elect to measure PP&E on the date of transition to IFRSs at its fair value and use that fair value as its deemed cost at that date. IFRS 1 includes an additional optional exemption that permits regulated entities not to restate PP&E amounts at initial adoption for assets subject to rate regulation even if amounts noncompliant with IAS 16 were capitalized in PP&E before transition (see the discussion in Property, Plant, and Equipment above for further details).

- Entities adopting IFRSs may elect not to apply the guidance in IFRSs on the accounting for business combinations retrospectively to business combinations that took place before the date of transition to IFRSs.

- First-time adopters may apply the transitional provisions in IFRIC 4, which allows them to base their determination of whether an arrangement existing on the date of transition to IFRSs contains a lease on the facts and circumstances existing at that date.
- Classification and measurement and embedded derivative exceptions.

Section 4
Industry Accounting Hot Topics

Asset Retirement Obligations — Nuclear Power Operations

Nuclear power plant operators are required to recognize asset retirement obligations under ASC 410 for legal obligations associated with spent nuclear fuel, which generally is viewed as a tangible long-lived asset. As a result of assessing their contractual requirements, many nuclear plant operators have included the cost to remove spent nuclear fuel in their recorded asset retirement obligation because they have concluded they have a legal obligation to pay for those costs.

Under the Nuclear Waste Policy Act of 1982 (NWPA) as amended, the federal government entered into "standard contracts" with the operators of nuclear power plants for transportation and ultimate disposal of spent nuclear fuel. To pay for this service, nuclear power plant owners are required to contribute to a nuclear waste fund. Under the NWPA, the DOE was required to begin taking possession of the spent nuclear fuel by no later than January 31, 1998. Certain nuclear power plant operators entered into settlement agreements with the DOJ to compensate them for the DOE's continuing refusal to accept spent nuclear fuel. As a result of the settlement agreements, these operators were reimbursed for allowable and reasonable costs incurred in connection with the temporary storage of spent fuel. While the agreements are individually negotiated and may have different terms, certain settlement agreements also allow for future reimbursement of allowable and reasonable costs associated with the temporary storage of spent fuel until the DOE begins to accept the spent fuel.

If a settlement agreement specifies a reimbursement for previous costs incurred, a company should record the reimbursement consistently with its policy for recognizing the original spent fuel removal costs; that is, either as a reduction of capitalized costs or as a reduction of previously recognized expense.

In addition, companies should consider the impact a settlement agreement may have on their asset retirement obligation associated with spent nuclear fuel. If a company concludes it has a legal obligation to pay for the cost of disposal, the next challenge is measuring the asset retirement obligation at fair value. Some companies have concluded through a thorough legal analysis that their settlement agreements convey rights to cost reimbursements that are attached to the nuclear power plant. Under this conclusion, companies point to the fair value accounting guidance in ASC 820 and assert that a third party would consider the value of the settlement agreements when determining a market price for the plant. As a result, companies would consider the expected cash inflows associated with the settlement agreement when using a discounted cash flow approach to calculate the fair value of the asset retirement obligation associated with spent fuel.

However, other companies have concluded that receivables under the settlement agreement should be recognized when expenses are incurred. Under this accounting model, recognition of reimbursements would be delayed into the future and would not offset the recorded asset retirement obligation. Companies should adopt the appropriate accounting policy on the basis of the facts and circumstances of the specific settlement agreement and their accounting policies in prior similar circumstances.

Normal Purchase Normal Sale Scope Exception

ASC 815-10-15-35 states that "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 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.

Impact of Contract Modifications and Force Majeure

As they have in the past, flooding or other disasters in certain parts of the country have resulted in challenges related to receiving delivery of coal quantities under contract for companies with coal-fired generation. Companies may have therefore experienced increased cycle times; modified coal contracts by negotiating delayed deliveries or a reduction in contractual volumes, prices, or both; or invoked *force majeure* provisions under the terms of the existing contracts. Entities should carefully evaluate modifications and *force majeure* provisions to determine 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.

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 what impact invoking such provisions has on the entity's rights and obligations under the contract, including whether invoking such provisions results in net settlement.

Impact of Reduced Purchase Quantities

In recent years, reduced demand for coal-fired base load generation has resulted in an increase in the amount of coal inventories held by companies with significant coal-fired generation at the end of each reporting period. Decreases in demand may affect the accounting for existing 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 availability.
- Increased use of lower sulfur coal or early plant retirements to comply with CSAPR.

In addition to making determinations related to modification of coal contracts, certain companies may be negotiating cash settlements or entering into offsetting positions. Entities should carefully evaluate modifications, early cash settlements, and offsetting contracts to determine the impact on their ability to assert that a contract in question and other similar contracts will not settle net and will result in physical delivery. In addition, entities should consider whether their ability to enter into offsetting positions indicates that the coal they are buying is "readily convertible to cash" as that phrase is used in the determination of whether a contract meets the definition of a derivative.

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 RECs are obtained by electricity suppliers, (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.[11]

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. [Emphasis added]

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.[12] 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 they 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.

[11] 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.

[12] 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.

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 to comparable fact patterns.

Derivative Considerations

Distinction should be made between the accounting for the actual REC and the accounting for forward contracts to buy or sell RECs. Although RECs are not derivatives, contracts exchanging RECs may meet the derivative criteria. As noted above, 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 readily convertible to cash) 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 contracts to buy or sell RECs must be continually evaluated over their lives, those that did not previously qualify as a derivative may later meet the definition. Therefore, consideration should be given to "conditional" NPNS designation to reduce the risk of the potential impact to the financial statements as REC markets develop.

In addition, RECs may be combined in some contracts with the purchase or sale of energy; energy is generally considered to be readily convertible to cash. 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 (and there are likely to be many more in the near future) currently affected by carbon emissions and related issues have developed accounting policies in the absence of explicit authoritative guidance. See Section 7 for additional discussion of the FASB's and IASB's 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." For additional discussion about issues related to accounting and presentation of environmental assets, see Deloitte's October 28, 2009, *Carbon Accounting Challenges: Are You Ready?*

Asset Type

The majority of companies classify RECs currently held 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.
- Cash flow statement 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 utilize 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. In such situations, the accounting value should generally be based 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.[13]

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 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 costs allocated to the RECs and less costs 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 later than electricity.

[13] The accounting value models described in this section are applicable to RECs accounted for as "inventory." ASC 350-30 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.

By-Product Allocation

In some circumstances, RECs may be considered a by-product of electricity generation. In other fact patterns (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. Consideration should be given to 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*.[14] 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 of market" inventory or amortized intangible impairment considerations.

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 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.

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 played by 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 measurements that was later codified as ASC 820, including measurement of assets and liabilities as of the acquisition date.

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

[14] 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.

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 the assets by market participants, utilities should consider the following:

- Whether regulation is an attribute of the entity or whether it attaches to the individual assets.
- The mechanism for recovery and whether the assets and liabilities are subject to rate recovery.
- The nature of the assets (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 assets, such as the following:
  - Regulatory approval is required before the sale or disposition of utility assets.
  - The gain on the sale of regulated assets is required to be shared with the regulated customers.
  - Use of assets 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 in most instances regulation attaches to the 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, regulatory assets or property acquired is not allowed to earn a return. 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.

Depreciation Adjustments

Economic pressures can lead regulators to seek reductions in rates charged to utility customers, often by adjusting excess depreciation reserves or normalizing utility returns via adjustments to prospective depreciation expense. The U.S. GAAP considerations associated with these types of regulatory actions are discussed below.

"Mirror Depreciation"

If a utility has recorded 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 has the latitude to 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 a legal requirement 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 (as discussed below) because negative depreciation is not a rate-making method that has been routinely used by any regulator 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 also prohibits the capitalization of the allowable costs that are deferred for future recovery by the regulator under a phase-in plan. A regulatory order that modifies the recording of depreciation or other allowable costs to normalize the return on equity for customer rates associated with a newly completed major capital project (including a capital lease) may meet the definition of a phase-in plan.

Abandonment Accounting, Including Impairment Considerations

ASC 980-360 provides guidance on two topics related to rate-regulated utilities: accounting for abandonments and disallowances of recently completed plants. The provisions in ASC 980-360 on plant abandonment apply to an operating plant or a plant under construction. When it becomes probable that an operating or under-construction plant will be abandoned, the associated cost should be removed from plant-in-service or construction work in progress, respectively.

Impairment Considerations

ASC 360-10-35 addresses financial accounting and reporting for the impairment or disposal of long-lived assets. This standard applies to all entities, including rate-regulated utilities. Specifically, ASC 360-10-35 states that a long-lived asset (asset group) is tested for recoverability whenever events or changes in circumstances indicate that its carrying amount may not be recoverable. ASC 360-10-35 notes the following as an example of such events or changes in circumstances: a current expectation that, more likely than not, a long-lived asset (asset group) will be sold or otherwise disposed of significantly before the end of its previously estimated useful life. The term "more likely than not" refers to a level of likelihood that is more than 50 percent.

For long-lived assets to be held and used, ASC 360-10-35 requires the recognition of an impairment loss only if the carrying amount of a long-lived asset is not recoverable from its undiscounted cash flows. It states that an impairment loss is measured as the difference between the carrying amount and fair value of the asset.

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." For plants, the asset grouping should take into account all relevant facts and circumstances. In some cases, cash flows are identifiable at the individual plant level. In other cases, a group of plants (and related customer contracts) may constitute an asset group. For many rate-regulated utilities, the entire generating fleet as well as purchased power is 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. Support for grouping assets in a rate-regulated environment is discussed further below.

In its May 29, 1998, letter to representatives of various major accounting firms, the SEC staff stated the following, which continues to provide relevant guidance on applying ASC 360-10-35:

> When performing an impairment calculation in accordance with FASB Statement No. 121 [which has been superseded], we would expect plant assets to be grouped at the lowest level of identifiable cash flows that are largely independent of the cash flows of other plant assets. We presume that generally would be on an individual plant basis, however, we understand that there may be circumstances where aggregation on some other level would be appropriate. We do not believe that an entity may solely rely on the manner in which those assets are intended to be managed in order to make the aggregation decision.

Once the utility industry started its now delayed shift from a focus on cost recovery (i.e., regulated) to being a low-cost provider (i.e., deregulated), decisions were increasingly made on an asset- or plant-specific basis by both management and regulators. This change was evident in regulatory jurisdictions that adopted industry restructuring plans and in the financial statements of affected entities that discontinued ASC 980-10 and applied the provisions of ASC 980-20. In practice, such entities generally performed impairment tests pursuant to ASC 360-10-35.

However, for rate-regulated utilities that continue to be subject to traditional, cost-based rate regulation, some grouping of assets is appropriate, even though discrete cash flows could be identified at a lower level of aggregation. The guidance and examples in ASC 360-10-55-35 through 55-36 indicate that long-lived assets could be grouped when there is a service obligation (and pricing of services) on the basis of the operations of the group of assets as a whole.

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 this 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.

Facts and circumstances should govern the level at which entities perform the ASC 360-10-35 impairment analysis. Among regulatory jurisdictions, such facts and circumstances will differ depending on the status of industry restructuring toward competition and on an entity's operating characteristics.

Abandonment Accounting

As stated above, ASC 980-360 provides guidance on accounting for abandonments of plants in a rate-regulated environment and states that when it becomes probable that an operating or under-construction plant will be abandoned, the associated cost should be removed from plant-in-service or construction work in progress, respectively. 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 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 plant 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 plant 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 plant. ASC 980-360 outlines the specific guidance.

SAB Topic 10.E 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 plants 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 plant abandonments in a regulated environment; however, a careful assessment of a utility's facts and circumstances is required in the determination of what constitutes abandonment of a plant 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 a plant 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 a plant is to be retired, but not in the "near future" and not "much earlier than its previously expected retirement date," then 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 plant in accordance with ASC 360-10-35. Under this accounting, depreciation would be accelerated to fully depreciate the plant 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 due to a change in depreciable life is not reflected in rates currently or expected to be reflected in rates in the near future.
- The plant is to be retired sooner than its remaining useful life and in the near future.
- Reduction in estimated remaining depreciable life is reduced by more than 50 percent.

Other matters that should be considered related to a probable abandonment of a plant would be the abandonment's impact on related items such as materials and supplies and asset retirement obligations directly associated with the plant.

Disallowances of Recently Completed Plant

As noted above, ASC 980-360 provides guidance on accounting for both abandonments and disallowances of recently completed plants. If a rate-regulated utility has an unregulated affiliate with costs recorded for a recently completed plant, such costs should be evaluated for impairment under ASC 360-10-35. If the 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" nor is there 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, for both a self-constructed and acquired 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. If that period approximates 12 months or less, it would also be reasonable to conclude that the plant is recently or newly completed under ASC 980-360 and ASC 980-340.

Disallowances

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.

Impact of Subsequent Events Related to Regulatory Matters

Developments often occur in regulatory proceedings after the balance sheet date but before financial statements are issued. 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 to situations faced by P&U companies.

ASC 855 prescribes the accounting for events and transactions that occur after the balance sheet date but before financial statements are issued. 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

For a loss contingency that was being evaluated as of the balance sheet date, including situations in which no accrual had been recognized, resolution of that loss contingency after the balance sheet date but before issuance of the financial statements should be recognized in 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. In the case in which 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, the loss would not be recognized but may need to be disclosed to keep the financial statements from being misleading. For example, if an accident occurred after the balance sheet date and the company faced liability exposure, no amounts related to the accident should be recognized 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 this 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 are intended to illustrate how the guidance might be applied to typical subsequent events encountered in the industry. In applying the guidance outlined above, companies should give appropriate consideration to the particular facts and circumstances.

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 the revenue is originally recorded, the criteria in ASC 450-20-25-2 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 payers. In this example, the regulator's decision is considered a Type 1 subsequent event. Therefore, B appropriately reversed the previously recorded reserve. If the approved final rates had been lower than the implemented interim rates, and the previously recorded reserve was not sufficient to cover the amount required to be returned to the customers, the reserve would also be adjusted accordingly.

Appeal of Prior Unfavorable Rate Order

In a prior period, Utility C's regulator had ordered that a gain on a sale of an asset must 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 didn't 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 prudency review in the current regulatory process.

EPA's Mercury and Air Toxics Standards and Its Cross-State Air Pollution Rule

Background

On July 6, 2011, the EPA issued the CSAPR, which called for power plants in 27 states to reduce sulfur dioxide (SO_2) and nitrous oxide (NOX) emissions via a new cap-and-trade program for emission allowances beginning January 1, 2012. However, since the CSAPR's issuance, several events have caused uncertainty about the nature and timing of the rule as currently written. Most significant was the decision by the Court of Appeals for the D.C. Circuit on December 30, 2011, to stay the implementation of the CSAPR.

Industry observers note that the courts did not specify the rationale for the issuing the stay, and because of the volume of claims made by the petitioners, it is difficult to assume which petitioner claim(s) the court views as having merit. Therefore, the nature and timing of the revisions, if any, the court may require are uncertain. Some industry observers believe the effects of the stay will be limited to timing or to minor changes to the rule, while others believe the stay could result in a rewrite of the entire rule. In the meantime, the Court of Appeals ordered the EPA to reinstate the predecessor program, CAIR.

With the delay in implementing the CSAPR, the environmental focus of the E&R industry has shifted to the Mercury and Air Toxics Standards (MATS),[15] issued by the EPA on December 16, 2011. MATS aim to set a national standard for mercury emissions. According to the EPA, the final rule establishes power plant emission standards for mercury, acid gases, and nonmercury metallic toxic pollutants that will result in (1) preventing about 90 percent of the mercury in coal burned in power plants from being emitted into the air, (2) reducing 88 percent of acid gas emissions from power plants, and (3) reducing 41 percent of SO_2 emissions from power plants. These amounts are in addition to the reductions expected from the CSAPR. Under MATS, reductions are to be achieved beginning in the first quarter of 2015. Available technologies that power producers are expected to employ to reach the prescribed mercury targets include selective catalytic reduction (SCR) with flue-gas desulfurization, activated carbon injection (ACI), ACI with fabric filter (FF), and electrostatic precipitators (ESP). For more information on MATS, including information on targets, penalties, and technologies expected to be used to address other toxics, see the EPA's Web site.

Company Plans in Response to CSAPR and MATS

While the January 1, 2012, implementation of CSAPR has been stayed, power producers expect that some form of an emission allowance cap-and-trade program will take effect within the next few years that will replace the EPA's CAIR program. Companies are evaluating a number of strategies to comply with these rules or expected rules, including early retirement of certain plants, retrofitting existing plants with emissions reduction equipment, reducing planned dispatch, changing the fuel mix of generating units, or designing flexible dispatch plans depending on the price and availability of allowances in the market. Companies are also considering temporarily idling plants for a period. If the stay of CSAPR issued by the courts is vacated (or a similar rule is issued), the greatest challenge for companies will be achieving the SO_2 reduction limitations. The industry is expected to be able to achieve the targeted NOX reductions with less difficulty and in many cases with existing equipment. Companies are facing similar decisions with respect to MATS; however, given that compliance is not required until 2015, there is more time to make investment and operational decisions.

Accounting Considerations

The accounting considerations and potential impact of MATS and CSAPR[16] 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. Companies with questions about the accounting considerations associated with the CSAPR and MATS are encouraged to consult with their accounting firms.

Considerations for Both Regulated and Nonregulated Plant Owners

Questions that both regulated and nonregulated plant owners might wish to consider include the following:

How do the rules affect determination of the asset group (the lowest level for which identifiable cash flows are largely independent of other assets) in the application of the long-lived asset impairment test?

It is important for companies applying ASC 360-10-35 to determine the asset grouping for long-lived assets held and used. In assessing, measuring, and recognizing impairment losses, companies should group a long-lived asset or assets at the lowest level for which cash flows are largely independent of the cash flows of other assets and liabilities. For power plants, the asset grouping should take into account all relevant facts and circumstances. In some cases, cash flows may be identifiable at the individual power plant level. In other cases, a group of power plants and related customer contracts may constitute an asset group, such as when a group of plants, rather than any specific plant, are dispatched to supply power to customers. Many rate-regulated operations use the entire generating fleet as well as the transmission and distribution assets to meet the utility company's obligation to serve, and the cash flows from regulated customers cannot be identified to any subset of assets.

[15] This rule is better known as the "Utility MACT" or Mercury MACT.

[16] References to CSAPR are to the rule as it was issued on July 6 and presume that any replacement rule after judicial review would be similar.

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 CAIR allowances are included in the asset group because the EPA is eliminating those allowances with CSAPR. Because the court stayed CSAPR, CAIR is still in effect at least temporarily. Many observers believe that CAIR will only remain in effect for an additional year or two at the most. Note that even if CSAPR is fully upheld in the judicial review process, acid rain allowances may continue to be included in those groupings to the extent that power plant owners intend to use them in complying with the acid rain program. In determining the number of acid rain allowances that will be held for use, companies should be careful to ensure consistency with the forecasted SO_2 emissions and usage of CSAPR SO_2 allowances.

Under ASC 360, an asset that is not held for sale is considered held and used until the asset is abandoned; that is, when the company ceases to use it. An individual power plant that is part of a larger power plant asset group, and that a company expects to retire early, should remain in the asset group for the held-and-used impairment evaluation until the period the plant has been retired. A plant that has been temporarily idled is not considered to be abandoned under ASC 360, so the plant should remain in the asset group until abandonment. Depreciation should not be suspended during periods that equipment is temporarily idled. For a plant that is to be retired early, a company should prospectively revise depreciation estimates to reflect the revised expected retirement date. That estimated remaining life should be revised no later than the date a company has committed to an earlier retirement date. The company should also consider other impacts of the earlier retirement date, such as the estimate for asset retirement obligations. (Note that a regulated company may need to assess for a potential ASC 980 disallowance; see discussion below.) Companies should also evaluate other impacts of the CSAPR. For example, generation output may be expected to decline for some companies as a result of the CSAPR. Those companies may need to reassess the probability of delivery for contracts designated as "normal" or the probability of the forecasted power delivery occurring for derivative contracts designated in hedge accounting relationships.

Does the issuance of the CSAPR or MATS trigger a requirement to perform a long-lived asset impairment test for power plant asset groups?

ASC 360 states that an asset group should be tested for recoverability whenever events or changes in circumstances indicate that its carrying amount might not be recoverable. ASC 360 lists several examples of such events or changes in circumstances. One example is a significant adverse change in the extent or manner of an asset's operation. Another example is a significant adverse change in legal factors or the business climate that could affect the value of an asset.

A company's facts and circumstances will influence how the EPA rules are expected to affect plant operations or the value of power plants in an asset group. We believe that the issuance of the EPA rules is consistent with the example in ASC 360 regarding a change in legal factors or the business climate. Each company will independently assess whether the change resulting from the issuance of the CSAPR, MATS, or both is significant enough to indicate that the carrying amount of an asset group might not be recoverable. For example, for a regulated company that has an asset grouping of all of its rate base assets, the undiscounted future cash flows are typically substantially greater than the carrying amount of the asset group (i.e., there is significant "headroom"). We would not expect an ASC 360 trigger to have occurred if the rule may result in some early plant retirements because the carrying amount of the asset group is expected to be recoverable despite the rule's impacts. (Note that the regulated company may need to assess for a potential ASC 980 disallowance; see discussion below.)

If an impairment test is triggered for an asset group, how should a company estimate undiscounted cash flows if the company is evaluating various courses of action to comply with the CSAPR and/or MATS?

When alternative courses of action are under consideration, the likelihood of possible outcomes should be taken into account. It may be useful to probability weight the various scenarios as a way to assess the likelihood of the various outcomes.

Additional Considerations for Rate-Regulated Plants

Rate-regulated plants might want to consider the following:

What accounting is required if, because of the CSAPR or MATS, it becomes probable that a power plant will be retired much earlier than its previously estimated useful life?

A rate-regulated entity should determine whether it must apply an ASC 980 disallowance test. On the basis of ASC 980-360-35, that test must be applied whenever it becomes probable that an operating asset will be abandoned.

What constitutes abandonment, and at what point does it become probable that an operating asset will be abandoned?

The issuance of the CSAPR in the third quarter, and MATS in the fourth quarter, of 2011 has caused companies to assess whether power plants will be retired early. Companies must carefully determine what constitutes abandonment of an asset and the likelihood that abandonment will occur. ASC 980 provides no explicit guidance on what constitutes an abandonment of an operating asset. We believe that abandonment is probable if a power plant will be retired in the near future and much earlier than its previously expected retirement date and that it is therefore subject to the ASC 980 disallowance test and classification requirements. We also believe that a power plant that will be retired sooner than expected, but whose remaining life is still substantive, would generally not be considered an abandoned plant.

For example, assume that a power plant was previously estimated to operate for 12 more years. In the current period, the plant owner decides to retire the plant 18 months from now. We believe the plant should be accounted for as an ASC 980 abandonment. Now assume that a power plant was previously estimated to operate for nine more years. The plant owner decides to retire the plant five years from now when a replacement plant is expected to commence operations. The increase in depreciation expense from the life revision will be fully recovered in future customer rates by the plant retirement date. We do not believe the plant should be accounted for as an abandonment under ASC 980.

While a regulated company may be considering the possibility of retiring a plant or plants early, the key accounting determination is when the likelihood of an early retirement of a specific plant becomes probable. In most cases, we do not believe that a general expectation that some portion of a company's generating fleet will need to be retired early constitutes a probable abandonment of any specific plant or plants.

Management must exercise significant judgment in determining whether an early plant retirement constitutes abandonment and when abandonment becomes probable.

If an early retirement of a regulated operating power plant becomes probable, how is the disallowance measured under the ASC 980 disallowance test?

A disallowance charge is required if the regulator is providing less than a full recovery of, and return on, the unrecovered plant balance. ASC 980-360-35 presents several examples of (1) how a disallowance charge is computed and (2) subsequent income recognition after the period the loss is recorded.

What classification changes are necessary if an early retirement of a regulated operating power plant becomes probable?

Under ASC 980-360-35, once it becomes probable that an operating asset will be abandoned, that asset (the remaining amount after any disallowance charge) must be reclassified outside of "plant in service." This is unlike the practice for nonregulated operating assets, which must continue to be classified as "held and used" until the date of abandonment. ASC 980 states that the cost is reported as a separate asset, but it does not provide guidance on how the separate asset should be described, or where that asset should be classified, other than outside of plant in service. Among other possibilities, such separate asset could be classified within regulatory assets or within total plant but not within a plant in service subgrouping.

What Disclosures Should Be Considered?

We would expect that because of the potentially significant impact of the rules, companies would have disclosures related to them in their quarterly and annual SEC filings. The notes to the financial statements should include the required disclosures for any impairment charges recognized in the quarter. Companies should also consider contingency and commitment disclosures as well as a description of the CSAPR and MATS rules, the court's stay of CSAPR and reinstatement of CAIR, the expected effect on the company and company plans to comply, liquidity, potential for future impairments, and risk factors, among other disclosures.

Section 5

Energy Contracts, Derivative Instruments, and Hedging Activities

Introduction

With certain exceptions, such as the sharp decline in natural gas prices seen in November and December, 2011 energy prices were relatively stable when compared with those witnessed during the peaks of 2008 and valleys of 2009. It was a tumultuous year, to say the least, from the ongoing troubles in Greece to the U.S. government's indecisive approach to the debt ceiling. The energy and commodity markets have continued to digest news about the increasing impact of U.S. shale gas reserves as well as legislation under the CSAPR, which was originally meant to take effect at the start of 2012. In addition, electricity and coal markets have seen a lot of merger and acquisition activity. Nevertheless, the impact of new regulatory measures, including both the Dodd-Frank Act and the CSAPR, remains to be seen.

The accounting for derivatives has been the subject of proposed rulemaking changes; however, the timing and extent of the changes are uncertain at the moment. This section summarizes current trends and activity in the energy industry and how potential changes may affect accounting and reporting for derivatives and risk management efforts.

IFRS Updates

At the end of 2010, the SEC introduced the term "condorsement" to describe a proposed approach to the U.S.'s transition to IFRSs. The overarching impact of this approach is discussed in Section 3 above, but its impact on accounting and reporting for derivative transactions remains uncertain.

On the basis of the IASB's hedge accounting ED released by the FASB for comment in February 2011, the proposed approach would make several changes to hedge accounting to align it more closely with an entity's risk management activities. The following changes would be of particular note for energy industry participants interested in applying hedge accounting:

- The allowance of certain specific financial or nonfinancial risks as a hedged item within a relationship.
- The ability to "rebalance" a hedge relationship in response to changing conditions and to avoid discontinuing the hedge relationship.
- The lowering of the threshold to achieve hedge accounting. The threshold of assessment of a hedge relationship's effectiveness would no longer be "highly effective" but instead would be a lower level of offset.

Furthermore, an exception can be applied to many energy related contracts that are referred to commonly as "own use" contracts under international accounting standards and as NPNS contracts under U.S. GAAP. International standards would rarely allow an industry-specific exception to an accounting rule, like the NPNS election for capacity-type contracts, which is commonly used in the electricity sector. Current IFRS rules are not as lenient in the application of scope exceptions for electricity contracts between two wholesaling entities.

Regulatory Activity

Rulemaking by the CFTC Under the Dodd-Frank Act

The Dodd-Frank Act was created in response to the financial crisis in 2008 and was designed to increase accountability, foster transparency, and reduce systemic risk in financial markets. Under the Act, the CFTC has certain rulemaking obligations. Accordingly, the SEC has "substantially completed" the proposal phase of rules in more than 30 different categories. It began finalizing the rules in July 2011 and since then has completed over a dozen rules. The CFTC has set July 2012 as the new tentative deadline for finalizing its rules. Effective dates for compliance vary by rule and will become known when the final rules are published.

Much of this legislation is aimed at Wall Street, but the new OTC derivative regulations created by the CFTC, which is now a major energy markets regulator, will most likely also affect energy entities. Most of the key provisions for the energy industry are in Title VII of Dodd-Frank. The ultimate definitions of certain terms, such as "hedging activity," "swap," "swap dealer," "end user," and "substantial position in swaps," or the way such terms are quantified, could be of significant concern to entities that transact in commodities. For instance, a broad definition of "swap" could ultimately be disruptive to liquidity in some regional markets or result in a shift to increased physical transacting.

Currently, there is an end-user exception applied on a deal-by-deal basis by nonfinancial firms to certain transactions in which swaps are used for hedging under accounting or economic standards and thus are not related to speculative activity. Even if the end user qualifies for this exception, it still has certain reporting requirements (i.e., as additional pieces of information must be provided to a swap data repository by the reporting entity).

With Dodd-Frank, Congress created provisions that will have significant implications for energy companies and other companies that hedge significant quantities of energy. For example, the Act:

- Extends CFTC authority to derivatives.
- Establishes central clearing and exchange trading for derivatives.
- Mandates data collection and publication to enhance market transparency.
- Establishes capital and margin requirements as financial safeguards.
- Amends trading practices to enhance market integrity.
- Exempts certain end users from some requirements.
- Requires disclosure of payments by oil, gas, and mining companies to foreign governments.

The CFTC has moved aggressively to implement its statutory obligations under the Dodd-Frank Act. Its actions include proposed rules on:

- Reporting requirements (transaction data capture and recordkeeping, real-time reporting, daily trading, P&L reconciliation with general ledger, compliance assertion, etc.).
- Central clearing (core principles, capital and margin requirements, portfolio margining, etc.).
- Trade practices (anti-manipulation rules, anti-disruptive trade practices rules, etc.).
- Position limits (aggregation across trading systems, reconciliation between physical and financial positions).
- Other regulations (new whistleblower rules, business conduct standards, exemptions and exceptions, business continuity capabilities, compliance organizations, etc.).

An entity should ask questions and evaluate the impact of these rules by:

- Responding to rules by participating in relevant rulemaking with the CFTC.
- Becoming aware of its specific situation in determining the type and volumes of transaction and market participant classification.
- Assessing its capability to handle requirements concerning people, processes, systems, and governance structure.
- Evaluating how this law will change its risks and opportunities going forward.
- Planning priority tasks and activities given expected outlooks.
- Assessing time and budget issues.

More information about the Dodd-Frank Act is available on the CFTC's Web site.

The Cross-State Air Pollution Rule

The CSAPR, issued by the EPA to replace CAIR, was finalized on July 6, 2011. The rule requires companies in numerous states to reduce power plant emissions of SO_2 and NOX, both believed to contribute to ozone and fine particle pollution. Phases of the rule were meant to go into effect January 1, 2012, but a stay granted by a U.S. federal court will delay implementation. The impact of the stay on the content and timing of the final ruling remains to be determined. In its current form, the rule establishes new emissions allowances that will require plants to install or upgrade pollution control equipment and switch to cleaner fuels. Compliance will be distinct from prior programs, eliminating carryover of the acid rain program and CAIR allowances. The rule is projected to reduce SO_2 emissions by 73 percent and NOX emissions by 54 percent by 2014.

The CSAPR may result in changes to the fundamental economics associated with the cost to maintain a plant (e.g., power prices, fuel costs, operation and maintenance, or significant capital expenditures). Companies may be faced with having to assess costs associated with significant capital to install, run, and update pollution control equipment; purchase costly new emission allowances; or retire plants early. The rule could also result in an impairment triggering event, creating the need for an impairment analysis to be performed on these assets, which may need to be disclosed in the current period. See further discussion regarding the need for an impairment analysis in Section 4.

There are other accounting and disclosure implications as a result of this new rule:

- *Assertions related to hedge accounting and election of derivative transactions as normal* — The application of derivative accounting elections (hedge or normal) is directly related to certain assertions an entity makes about its business strategy or operations. Because the CSAPR changes the operations of key assets of an entity's business, the entity must revisit certain assertions to determine whether (1) the derivative sale will be fulfilled through the production of physical power, (2) there is sufficient generation to substantiate a highly probable sale of power, (3) the business strategy changes after operational revisions necessitated by the CSAPR.

- *Impairment of assets caused by hedge accounting* — Because of the CSAPR's impact on asset generation, and therefore the cost of generation dispatched by an entity, companies should consider any pools of assets that may have fixed-price hedging sales strategies in place and whether the price achieved under those sales strategies continues to exceed the cost to generate.

- *Derivatives over CAIR allowances* — Transactions for the forward sale or receipt of NOX or SOX certificates may have qualified as derivatives (the allowances themselves are not derivatives) under the CAIR program; however, under the CSAPR, such certificates will no longer have a carryover value and should be reassessed.

More information about the CSAPR is available on the EPA's Web site.

Market Activity

Some extreme weather events occurred in 2011, notably the record-breaking low temperatures in Texas and Hurricane Irene in the northeast. Texas had ERCOT-capped electricity prices in February as temperatures fell to historic lows and approximately 7,000 MW of generating capacity was taken off the ERCOT grid, causing a supply shortage and rolling blackouts. This chill was followed by a near record-setting heat wave, with periods of 20 consecutive 100-degree days in heavily populated areas of Texas.

ERCOT Nodal

ERCOT transitioned from a zonal to a nodal market in December 2010, 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 designed to improve the transparency of pricing, encourage additional generation and transmission investment, increase dispatch efficiency, and improve the assignment of congestion costs. Previously, power settlements were based on four broad pricing indices; however, under the new market design, power settlements are based on hundreds of individual nodal indices. As a result of the change, the following considerations remain relevant to accounting and reporting transactions in ERCOT:

- *Contractual obligations* — Because of the location of certain supply or sales commitments, some companies had to reexamine delivery obligations in the ERCOT market. In some cases, the companies renegotiated commitments to deliver (or take delivery of) electricity to move delivery locations from a zonal to a nodal location, or vice versa. Going forward, it may be necessary for entities to inventory delivery commitments when determining the fair value of contracts to ensure risks are appropriately considered in valuations recorded to the financial statements.

- *Fair value of derivative contracts* — Certain nodal-delivery contracts may qualify as derivatives, the accounting for which would include fair value estimates. Under ASC 820, observable market data must be prioritized over management estimates; however, it is unlikely that markets will have forward-looking information to support electricity pricing at individual nodes. Market participants have a year's worth of data on settlement pricing behaviors of the ERCOT nodes at present. However, determining the fair value of these contracts on the basis of that information may prove challenging, given the impact of the extreme weather activity in Texas in 2011. Companies with significant derivative positions relative to their financial statements will need to carefully consider how this data is used to establish a forward price for 2012 and beyond.

- *Hedge accounting* — Depending on the location of a company's contractual obligations, and the instruments in place to financially hedge those obligations, the move to nodal may have affected the company's assessment of the effectiveness of its hedges. In a regression analysis, the use of either historical settled pricing information or forward pricing estimates may be required for not only the derivative instrument but also the hedged location. Similarly, in a ratio comparison, the use of a forward-pricing estimate may be required for both the derivative instrument and the hedged risk. Because of the volatility in the Texas market during 2011, the use of historical pricing information to assess hedge effectiveness may yield surprising and unwanted results. If an assessment is based on a historical forward price, companies may find it challenging to develop quantitative evidence to support the assertion that a hedge is expected to be highly effective. Entities should carefully consider the inputs and modeling assumptions that factor into this assessment. For additional information about the impact of this market change on hedge accounting assessments, please contact a Deloitte Financial Accounting & Reporting Services (FA&RS) professional.

- *Congestion revenue rights (CRR)* — The CRR market is fairly young, and 2011 began with auctions for CRRs on a one-month-forward basis. During 2011, the market developed to allow for a six-month forward auction. Since these contracts qualify as derivatives (similar to FTRs in PJM), companies will need to consider how to value CRR auctions with delivery periods beyond December 2011 and consider presentation within the ASC 820 disclosures for Level 3 instruments.

Coal

The CSAPR broadly affects the electricity markets and will dramatically change the nation's energy dispatch over the next several years. It also affects the market for clean coal. The NYMEX contract currently calls for coal with less than one percent sulfur, 10 percent moisture content, and 13.5 percent ash content, along with other specifications. Contracts for delivery in or near the Powder River Basin (PRB) are generally considered derivatives in the energy industry because of active transacting and the ability to convert such commodities to cash. The changing regulations will undoubtedly reduce the demand for "dirtier" Illinois- and Appalachian-based coals and increase the demand for PRB products. Companies with coal transactions, whether related to trading and marketing or procurement, should be mindful of the changes when considering the completeness of contracts reported as derivative activity in financial statements.

Shale Gas

Shale gas has taken the U.S. energy market by storm over the past few years. With estimates for the Marcellus gas reserve ranging from around 84 TCF (U.S. Geological Survey) to 410 TCF (U.S. Energy Department), the impact of shale gas on the U.S. energy supply will undoubtedly be massive. Companies should consider the medium- and long-term impact of shale gas on the supply and demand for natural gas in the U.S. marketplace. Companies with transactions or assets that have cash flows outside of market-available information (e.g., cash flows that extend beyond the range that is actively transacted for NYMEX-based contracts or beyond the range for which NYMEX pricing can be obtained) should carefully consider forward prices being developed when performing impairment analysis of gas-based assets and when establishing fair value for contracts accounted for as derivatives.

More information is available at Deloitte MarketPoint and in Deloitte's July 2011 report Navigating a Fractured Future.

Merger and Acquisition Activity

A number of high-profile mergers and acquisitions took place in 2011. The following is a list of some of the considerations regarding the accounting and presentation of derivative activity upon acquisition:

- *Consistency of business strategy in accounting and presentation of derivative activity* — Merging entities or business units may result in changes to operating strategy. The presentation of derivative activity as net or gross in the statement of income must reflect such changes in strategy if the changes affect trading activity. Similarly, the NPNS scope exemption in ASC 815 requires that such transactions are executed in conjunction with an entity's normal course of business; entities should consider the ongoing implications of this election. The netting of financial instruments on the balance sheet must be applied consistently between merged entities. The merged entities may need to perform netting for positions previously held and presented by each company and eliminate positions if the counterparty is the newly merged entity.

- *Consistency of disclosure* — ASC 815 requires qualitative disclosure of an entity's strategies and objectives when it enters into derivative instruments. As mentioned above, entities will need to ensure that the notes to the financial statements reflect the activities and strategies of the newly merged entity. The entity will also need to consider other nuances related to the implementation of disclosure requirements, such as the Level 3 valuation inputs and unobservable input when assessing Level 3 instruments as part of disclosure activities.

- *Consistency of fair valuation method* — Under ASC 820, different approaches may be used to determine fair value as long as similar transactions are treated consistently. Merged entities will need to thoroughly consider methods, inputs, assumptions, and even allocations (e.g., assumptions around valuation of structured load-serving transactions or allocations of portfolio-level adjustments to valuations).

- *Application of hedge accounting* — In general, entities choose to either (1) apply hedge accounting (if eligible) to ensure that the financial statements reflect the risk management efforts by management or (2) decide that the costs of complying with hedge documentation requirements are too onerous to justify the recognition and presentation benefits. To align strategies for the application of hedge accounting, newly merged entities may find themselves "ramping up" to ensure appropriate documentation and eligibility of potential hedge accounting relationships. Other newly merged entities may educate investors and analysts to reconcile the appearance of risk management activities in the financial statements with the risk management activities intended and executed by management.

Multiple-Element Arrangements and the P&U Sector

The nature of physical electricity markets, transmission systems, and distribution networks is such that the production and delivery of energy involves multiple products and services. Those products may include capacity credits, various ancillary services, emissions allowances, and renewable energy credits. Although the electricity component is typically the main product in the contract, entities frequently execute contracts that combine energy with one or more of these additional products and services. The accounting for bundled contracts is complex and may require an entity to consider whether the various elements in the contract should be accounted for separately or together. For example, analysis of a contract can result in the identification of (1) a derivative instrument bundled with multiple other products or services, (2) a lease with other products and services rendered, or (3) a nonderivative or executory contract that contains multiple products or services rendered.

A contract that contains multiple elements should be analyzed carefully, and entities should consider the literature on derivatives, lease accounting, and revenue recognition:

- *Derivatives accounting* — The first step in analyzing a contract that contains multiple products or services is to determine whether the contract (1) meets the definition of a derivative in its entirety, (2) contains a derivative element with additional nonderivative elements, or (3) is more akin to a host contract with an embedded derivative as described in ASC 815. Depending on the conclusion, there may be additional complexities in determining the appropriate fair value to assign to the identified derivative instruments. For example, if it is determined the contract meets the definition of a derivative in its entirety, then the entire contract would be carried at fair value. If it is determined that the contract does not meet the definition of a derivative in its entirety, but that the contract contains both derivative and nonderivative elements, then only the derivative element would be carried at fair value. And if it is determined that the contact is more akin to a host contract with an embedded derivative, then the entity should follow the embedded derivative guidance in ASC 815, in which case the entity may value either the embedded derivative only or the entire contract if the embedded derivative cannot be separated from the host contract.

- *Lease accounting* — The lease accounting literature related to multiple-element arrangements can also be challenging. The primary issue in assessing a contract under the leasing literature is identifying the output of the referenced facility in the context of lease identification under ASC 840. Identifying the output is critical for two reasons: (1) to assess whether substantially all of the output is being purchased or sold under the arrangement and (2) to assess whether the price of that output is either fixed or at a market price per unit of output. In addition, a multiple-element contract executed at a bundled price can present problems when an entity is determining how to allocate the price to the lease and nonlease elements. Finally, a contract that contains a lease may contain other elements that require further accounting analysis (e.g., a derivative or variable interest).

- *Executory contract* — An entity may experience difficulty in determining the proper revenue recognition for contracts that are neither derivatives nor leases in multiple-element arrangements. If the contract contains multiple delivery obligations in different periods, it is important for entities to consider whether the seller's obligations have been fulfilled for each of the elements in determining the proper amount of revenue to record. Entities may want to consider the guidance in ASC 605-25 on revenue recognition for multiple-element arrangements.

In the context of derivative and lease accounting considerations, we have observed diverse practices in accounting for and reporting contracts with multiple deliverables or elements. When diversity exists and the accounting literature is silent, entities should adopt and consistently apply an accounting policy that reflects the economic substance of the underlying transactions.

Section 6
Fair Value Measurements

Recently Issued Guidance

In May 2011, the FASB issued ASU 2011-04. The ASU is the result of joint efforts by the FASB and IASB to develop a single, converged fair value framework — that is, converged guidance on how (not when) to measure fair value and on which disclosures to provide about fair value measurements.

The ASU is largely consistent with existing fair value measurement principles in U.S. GAAP (i.e., those in ASC 820). For instance, the ASU continues to define fair value as an exit price. Many of the amendments to ASC 820 were designed to eliminate unnecessary wording differences between U.S. GAAP and IFRSs. However, some of the amendments could change how the fair value measurement guidance in ASC 820 is applied. The following is a list of some of the ASU's more noteworthy amendments to the fair value measurement guidance and new disclosure requirements:

- *Highest and best use and valuation premise for nonfinancial assets* — The ASU indicates that the highest-and-best-use and valuation-premise concepts only apply to measuring the fair value of nonfinancial assets.

- *Application to financial assets and financial liabilities with offsetting positions in market risks or counterparty credit risk* — The ASU permits an exception to fair value measurement principles for financial assets and financial liabilities (and derivatives) with offsetting positions in market risk or counterparty credit risk when several criteria are met. When the criteria are met, an entity can measure the fair value of the net risk position.

- *Premiums or discounts in fair value measurement* — The ASU states that "[p]remiums or discounts that reflect size as a characteristic of the reporting entity's holding (specifically, a blockage factor that adjusts the quoted price of an asset or a liability because the market's normal daily trading volume is not sufficient to absorb the quantity held by the entity . . .) rather than as a characteristic of the asset or liability (for example, a control premium when measuring the fair value of a controlling interest) are not permitted in a fair value measurement."

- *Fair value of an instrument classified in a reporting entity's shareholders' equity* — The ASU prescribes a model for measuring the fair value of an instrument classified in shareholders' equity; this model is consistent with the guidance on measuring the fair value of liabilities.

- *Disclosures about fair value measurements* — The ASU expands ASC 820's disclosure requirements, particularly for Level 3 inputs. Required disclosures include:

  - For fair value measurements categorized in Level 3 of the fair value hierarchy: (1) a quantitative disclosure of the unobservable inputs and assumptions used in the measurement, (2) a description of the valuation processes in place (e.g., how the entity decides its valuation policies and procedures, as well as changes in its analyses of fair value measurements, from period to period), and (3) a narrative description of the sensitivity of the fair value to changes in unobservable inputs and interrelationships between those inputs.

  - The level in the fair value hierarchy of items that are not measured at fair value in the statement of financial position but whose fair value must be disclosed.

Implementation Issues Relevant to the Energy & Resources Industry

Although the ASU did not change ASC 820 significantly, the following practical implementation considerations may be useful in the preparation of disclosures or in the measurement of fair value:

- Some entities will want to scrutinize the level of disaggregation of instruments disclosed to ensure that the ranges provided for each input remain useful and meaningful to readers of the financial statements. For example, it may not be meaningful to disclose a range of volatility broadly under the classification of "commodity derivatives" when the volatility ranges presented encompass more than one commodity and those commodities' volatilities vary greatly.

- Since the example disclosure in the ASU is not specific to energy-related activity, entities may be challenged in disclosing certain assumptions relevant to energy transactions. For instance, for positions valued on the basis of an illiquid location, an entity may disclose the range in terms of the entirety of the locational price, or disclose the range in terms of the price's differential from an actively traded hub or location (i.e. as a basis spread).

- On the basis of the ASU, some entities may conclude that the ability to offset positions managed as a portfolio (the "portfolio exception") is limited to financial derivatives (i.e., disallowed for physical gas or power contracts that qualify as derivatives). However, recent discussions with the FASB have clarified that the ASU was not intended to prohibit measuring offsetting nonfinancial derivatives as a single unit of measurement.

- In applying the portfolio exception, the portfolio becomes the unit of measurement; therefore, positions may be offset and measured based on the net open risk. This type of measurement allows for a net liquidity adjustment or credit adjustment. However, some entities may conclude that an aggregated unit of measurement allows for an adjustment on the basis of the size of the portfolio (a block discount), which may be incorrectly viewed as a characteristic of the unit of measure under the portfolio exception. Blockage factors or block discounts are prohibited for all instruments measure at fair value under the ASU.

Section 7
Accounting Standards Codification Update

Overview

As noted in Section 3 of this publication, the FASB and IASB continued to actively engage in accounting standard-setting activities in 2011, largely in the form of redeliberations on convergence projects. The boards also continued to advance their own stand-alone projects and deferred some projects (both joint and stand-alone) to devote more attention to major joint convergence efforts (leases, revenue recognition, and financial Instruments). The discussion below summarizes certain of these projects from a U.S. GAAP perspective and highlights relevant, high-level industry impacts. A more detailed discussion of each project and related industry considerations follow this overview.

Fair Value Measurements

In May 2011, the FASB issued ASU 2011-04. The ASU is a result of the FASB's and IASB's joint project to converge U.S. GAAP and IFRSs regarding how to measure fair value and related disclosure requirements. For public entities, the ASU is effective for annual and interim reporting periods beginning after December 15, 2011 (i.e., the first calendar quarter of 2012), and for nonpublic entities it is effective for annual periods beginning after December 15, 2011. Among other items, the ASU (1) clarifies that the "highest and best use" and valuation premise concepts are only applicable to nonfinancial assets, (2) permits an entity to measure financial assets and financial liabilities on the basis of their net exposure to a particular market risk or counterparty risk, (3) provides guidance on using premiums and discounts in fair value measurements, and (4) expands disclosure requirements for Level 3 (unobservable) fair value measurements.

In particular, entities that incorporate portfolio-level fair value adjustments on the basis of net exposures (including credit and liquidity reserves) or that hold fair value instruments classified as Level 3 within the fair value hierarchy may be affected. Notably, while the ASU did not carry forward the initially proposed quantitative Level 3 "uncertainty" (sensitivity) analysis, qualitative discussion of Level 3 sensitivities and quantitative information about Level 3 inputs will still be required and may result in changes to related policies, processes, and controls.

Leases

Substantial redeliberation related to the lease project took place over the past year and resulted in many tentative decisions that changed the guidance in the boards' August 2010 ED. The ED's proposals, particularly related to the definition of a lease, initial and ongoing measurement requirements (estimation of lease term, contingent rents, etc.), and disclosures, caused considerable concern both within and outside of the industry. However, the revised decisions on these and other proposals in the ED have been largely viewed by most constituents as improvements. Given the magnitude of the changes to the ED's guidance, the boards have decided to reexpose the proposed standard (currently targeted for the first half of 2012).

Many of the tentative changes to the proposals in the original ED have been seen as positive developments for the industry. However, the "on-balance sheet" concept underlying the right-of-use model for lessees has been retained. Ongoing lessor model deliberations are also likely to result in changes to existing practice. Further, entities will still need to exercise judgment in implementing many aspects of the revised standard as currently proposed, including identifying which arrangements contain leases, measuring related assets and liabilities, and complying with substantial new disclosure requirements. For many, this will still represent a substantial undertaking, including modification of existing practices and potentially enhancing systems. Of note, while the boards decided to revise the definition of a lease in such a way that many traditional energy supply and take-or-pay arrangements may not contain leases, industry participants are encouraged to continue monitoring this and other aspects of the proposed standard to identify areas of unintended consequence.

Revenue Recognition

The boards also spent significant time in 2011 redeliberating their June 2010 ED on revenue recognition. In light of their extensive tentative decisions, the boards reexposed the ED in November 2011, with a 120-day comment period. Of particularly interest to the industry was the boards' decision to retain the specialized revenue recognition guidance in ASC 980-605 on alternative revenue programs of rate-regulated entities, which would have been superseded under the original ED and would have kept affected entities from being able to recognize certain profits under related regulatory programs.

The proposed revenue standard seems to have received relatively less attention from an implementation and preparation standpoint than the proposed lease standard, perhaps as a result of the obvious financial reporting and related process implications of the lease project. However, companies within the industry are encouraged to prepare well in advance for the final revenue standard. For example, the original ED's proposals on accounting for contract modifications would have most likely resulted in cumulative catch-up adjustments to earnings for blend-and-extend arrangements, a common type of modification in the industry. It is currently unclear whether the revised ED's changes to this guidance will actually result in a different outcome from that contemplated in the original ED. Perhaps more importantly, it is still uncertain how the core guidance on separation and satisfaction of performance obligations (and related transaction price allocation) should be applied to long-term power sales contracts and similar bundled energy arrangements (including renewable energy contracts or "green power" deals). If any degree of performance obligation separation is required under the final revenue guidance, a number of downstream implications will be triggered, including initial and ongoing measurement judgments and increased disclosure complexity. Thus, there could be policy, process, and system implications similar to those that have long been contemplated as a result of the proposed lease guidance.

Financial Instruments

In addition to addressing leases and revenue recognition, the boards spent considerable time redeliberating the financial instruments project in 2011 and made numerous tentative changes to their initially proposed guidance. Because each board approached the project differently (i.e., the FASB attempted to issue guidance in a consolidated manner while the IASB elected to tackle the project in individual phases), there were substantially more areas of initial divergence than in other major joint projects. The boards are trying to resolve these differences during redeliberations. Although the FASB has sought U.S. constituents' views on the IASB's hedge accounting proposals, it has yet to redeliberate the topic. The financial instruments project (along with the finalized offsetting project summarized below) has been cited by many as critical to the long-term success of the boards' ongoing convergence efforts, particularly in light of the SEC's May 2011 staff paper exploring the possible "condorsement" approach to the incorporation of IFRSs (see Section 3 for more information). Currently, we expect the boards to issue their proposed amendments on the classification and measurement and impairment models sometime during the first half of 2012; it remains to be seen whether, and if so, when the FASB will issue revisions to its originally proposed hedge accounting model.

A particularly notable tentative decision involves changes to the proposed classification and measurement criteria. As currently proposed, fair value through net income (FV-NI) will no longer be a "default" category, and an entity's own debt is much more likely to qualify for amortized cost treatment (previously a key concern of the industry, although new presentation guidance will still require entities to parenthetically disclose fair value). However, certain investments within NDTs could potentially be classified as FV-NI under the revised guidance, which was a concern previously raised by the industry broadly and by participants specifically with partially or fully deregulated nuclear operations that are unable to avail themselves of a regulatory offset under ASC 980. Separately, companies in the industry should pay particular attention to the FASB's progress on hedge accounting once it commences redeliberations. The FASB's ED, while making inroads into simplifying select aspects of hedge accounting (i.e., relaxing the current bright-line effectiveness assessment criteria), did not go as far as the IASB's proposals, which outlined a new objective for hedge accounting aligned with a company's risk management activities. Although the industry did not favor certain aspects of each board's proposals (i.e., prohibiting voluntary dedesignation), the IASB's proposal **would** allow for component hedging of nonfinancial risks in certain circumstances (i.e., NYMEX component of a forecasted physical natural gas purchase or sale), which the industry has long desired. Finally, the boards' proposed "expected loss" impairment model for open portfolio-managed loans and debt instruments has also changed, although it remains to be seen how the model will affect activities more relevant to the industry (i.e., trade receivables) and how related guidance on measuring credit losses will apply.

Balance Sheet Offsetting

The boards' January 2011 ED on offsetting proposed a converged standard for offsetting financial assets and liabilities by effectively modifying existing U.S. GAAP to conform to a slightly revised version of what is required today under IFRSs. This would have resulted in a substantial balance sheet gross-up exercise for many U.S. issuers, particularly companies that elect to net derivative instruments and related fair value collateral exposures under ASC 815 that are associated with MNAs containing only "conditional" or default-based rights of offset. Most U.S. industry preparers that transact in the energy markets and elect to net under U.S. GAAP would have been markedly affected. In fact, the energy industry is second only to the banking industry in its use of derivatives, and many in the industry avail themselves of the current netting provisions in U.S. GAAP.

Feedback received by the boards indicated no clear consensus on an overall model, although many stakeholders favored existing U.S. GAAP because it specifically contemplated derivative instruments. The boards quickly decided that the best approach going forward was to resolve the matter by (1) retaining their existing, respective presentation requirements and (2) achieving convergence through disclosures of both gross and net information. Both boards issued their final amendments in December 2011, effective for fiscal years beginning on or after January 1, 2013, and interim periods within those annual periods. Therefore, companies in the industry that do not elect to net derivative and related fair value collateral exposures under U.S. GAAP today will, in the future, need to assess all of their derivative contracts and overarching master agreements, capture and identify netting terms and associated amounts, and implement processes to compute related net exposures **as if** they elected to net on the face of the balance sheet.

Loss Contingency Disclosures

In July 2010, the FASB issued a proposed ASU that would (1) expand disclosures about loss contingencies, including the scope of "special remote" contingencies; (2) significantly increase required qualitative and quantitative disclosures; and (3) require a tabular reconciliation of changes in recognized loss contingency amounts by "class" of contingency. The ASU was issued in response to concerns raised by constituents on a related, more expansive 2008 ED. However, concerns such as having to disclose prejudicial information and the subjectivity in providing reliable estimates of some of the amounts proposed were generally viewed as not having been effectively addressed by the proposed 2010 amendments. For the time being, the project has been deemphasized. However, given the SEC's and PCAOB's ongoing focus on improving compliance with existing requirements, which they reiterated earlier in January of 2011, there is a reasonable likelihood that this project could be reactivated in the near future.

Emissions Trading Schemes

Accounting for emissions allowances and other tradable environmental rights (e.g., RECs and project-based offset credits) has been an on-again, off-again focus of both the FASB and IASB since the early 2000s and historically has been approached in a compartmentalized fashion. In February 2007, the FASB added a comprehensive project to its agenda to address the overall accounting model for such instruments and subsequently decided to combine efforts with the IASB. Substantial deliberations took place during 2010 and various tentative decisions were reached by the boards on recognition, measurement, and presentation associated with the instruments themselves and related emissions obligations. However, this topic was also later deemphasized to allow the boards to focus on their major joint convergence projects. Further action is not expected in the near term.

Nonetheless, industry participants (particularly in the unregulated generating space) should closely monitor this project for further developments because the tentative decisions reached thus far by both boards would result in an accounting model that is drastically different from practice under both prevailing U.S. GAAP and FERC regulatory accounting today. Namely, both assets (allowances) and the associated emissions obligation would be recorded and subsequently remeasured at FV-NI. Perhaps more importantly to affected preparers, the boards have tentatively decided in favor of an up-front liability recognition model predicated on the view that the allocation of allowances (not the act of emitting pollutants) is an obligating event that meets the conceptual definition of a liability. Note that the EEI authored and submitted to the FASB staff an accounting whitepaper articulating a consensus industry view on the boards' proposals along with justification for an alternative accounting model.

Rate-Regulated Activities

Although it may be common knowledge at this stage, it's worth repeating that there is no standard under IFRSs that is equivalent to the specialized industry accounting guidance in U.S. GAAP (i.e., ASC 980) that addresses the economic effects of cost-based rate regulation. Specifically, although the IASB issued an ED on a proposed international accounting standard in 2009, the project has been stalled with no clear indication of whether or when it will be resumed. Meanwhile, utilities subject to cost-based regulation in Canada (where first-time IFRS adoption was mandatory in 2011 for most Canadian public companies) have been forced to deal with this more rapidly than their U.S. counterparts. As a result, Canadian utilities have been pursuing different paths. Some took advantage of a special one-year deferral granted by the AcSB, which expired January 1, 2012; others are choosing to move forward with adoption and are reversing certain regulatory balances; others are listing their securities in the United States and adopting U.S. GAAP; and more recently, some have been filing and successfully receiving "exemptive relief" orders from their provincial securities regulators to allow them to submit their local filings on the basis of U.S. GAAP until years beginning in 2015.

Through the efforts of industry trade associations like the EEI and the AGA, individual industry member companies, and other affected parties (including the FERC), the U.S. utilities industry has been active in discussing the merits of the retention of rate-regulated accounting guidance on the domestic stage. These groups took advantage of the opportunity to comment on the SEC's May 2011 staff paper that explored a possible "condorsement" approach to IFRS incorporation, in which the opportunity for local or industry-specific guidance is contemplated given the lack of equivalent international standards (see Section 3 of this publication for more information). The EEI also authored a whitepaper sent alongside its comment letter on the SEC staff paper in which it articulated the nature of regulation in the United States and a technical justification for the place of regulatory accounting within either the United States or international conceptual frameworks. Throughout the past two years, these groups have also met with numerous local standard setters and regulators (e.g., the FERC, FASB, and SEC). As a result, the domestic regulatory community appears well educated on the issues and potential impacts. Most recently, both the EEI and AGA responded to the IASB's request for comment on its next three-year project agenda to encourage a joint approach between the FASB and IASB in developing an international accounting standard on rate-regulated activities.

Final ASU on Fair Value Measurement

On May 12, 2011, the FASB issued ASU 2011-04. The ASU is the result of joint efforts by the FASB and IASB to develop a single, converged fair value framework — that is, converged guidance on how (not when) to measure fair value and on what disclosures to provide about fair value measurements. Thus, there are few differences between the ASU and its international counterpart, IFRS 13.

The ASU is largely consistent with existing fair value measurement principles in U.S. GAAP (i.e., those in ASC 820). For example, the ASU continues to define fair value as an exit price. However, it also expands the disclosure requirements for fair value measurements under ASC 820. Further, some of the changes could revise how the fair value measurement guidance in ASC 820 is applied. Some of the ASU's more noteworthy amendments to the fair value measurement guidance and new disclosure requirements are outlined below.

Financial Assets and Liabilities With Offsetting Positions in Market Risks or Counterparty Credit Risks

Under the ASU, there is an exception to the basic fair value measurement principles for a reporting entity that holds a group of financial assets and financial liabilities with offsetting positions in market risks or counterparty credit risk that are managed on the basis of the entity's net exposure to either of those risks. This exception allows the reporting entity, if certain criteria are met, to measure the fair value of the net asset or liability position in a manner consistent with how market participants would price the net risk position. To use the exception, an entity must meet all of the following conditions:

- Manages the group of financial assets and financial liabilities on the basis of the reporting entity's net exposure to a particular market risk (or risks) or to the credit risk of a particular counterparty in accordance with the reporting entity's documented risk management or investment strategy.
- Provides information on that basis about the group of financial assets and financial liabilities to the reporting entity's management.
- Is required or has elected to measure those financial assets and financial liabilities at fair value in the statement of financial position at the end of each reporting period.

Regarding market risks, the ASU notes that a reporting entity should assess whether such risks being offset are "substantially the same." Factors to consider in this determination include (1) whether offsetting the group of assets and liabilities would mitigate the entity's exposure to a particular market risk and (2) whether the group of assets and liabilities reflects the entity's exposure to the particular risk for a particular duration. The ASU also describes how an entity should evaluate when to include the effect of the entity's net exposure to the credit risk of that counterparty (or the counterparty's net exposure to the credit risk of the entity) in the fair value measurement. The ASU indicates that the effect should be included "when market participants would take into account any existing arrangements that mitigate credit risk exposure in the event of default (for example, a master netting agreement with the counterparty or an agreement that requires the exchange of collateral on the basis of each party's net exposure to the credit risk of the other party)." The ASU further clarifies that in such cases "[t]he fair value measurement shall reflect market participants' expectations about the likelihood that such an arrangement would be legally enforceable in the event of default."

Note that the ability to consider the fair value **measurement** of a portfolio of financial assets and financial liabilities on the basis of net exposure does not affect the basis of, or the "unit of account" applicable for, financial statement presentation and disclosure for these instruments. A reporting entity must still comply with the financial statement **presentation and disclosure** requirements of other ASC topics (e.g., ASC 210-20, ASC 815-10-50), including ASC 820 disclosures. See the summary of the boards' offsetting project below for more information.

Disclosures

The ED would have required reporting entities to provide a quantitative sensitivity analysis for Level 3 recurring fair value measurements, showing the impact to these measurements from changes in unobservable inputs to reasonable alternative amounts. The proposal would have also required reporting entities to take into account the effect of correlation between unobservable inputs if such correlation was relevant to estimating the effect on the fair value measurement. Although the final ASU does not require such a quantitative disclosure, the FASB expects to revisit this potential disclosure requirement (which is currently included in IFRSs) as part of a separate project.

However, the ASU does expand the qualitative and quantitative fair value disclosure requirements. For fair value measurements categorized in Level 3 of the fair value hierarchy, the guidance requires:

- A description of the valuation processes in place (e.g., how the entity decides its valuation policies and procedures, as well as its analyses of changes in fair value measurements from period to period).
- A narrative description of the sensitivity of the fair value to changes in unobservable inputs and interrelationships between those inputs if a change in those inputs would result in a significantly different fair value measurement.
- Quantitative disclosures about unobservable inputs used in a Level 3 fair value measurement. An entity is not required to create quantitative information to comply with this disclosure requirement if the entity does not develop quantitative unobservable inputs when measuring fair value (e.g., the entity uses third-party pricing information or prices from prior transactions without adjustment).

Note that an example in the ASU illustrates the required quantitative disclosure requirements associated with unobservable inputs used in Level 3 measurements. The ASU's basis for conclusions further notes that the purpose of this information is not to give financial statement users the level of information that would be necessary to "replicate the reporting entity's pricing models but to 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."

In addition, the ASU requires disclosures about:

- The highest and best use of a nonfinancial asset when this use differs from the asset's current use. The reporting entity should also disclose the reason for such a difference.
- For transfers between levels, ASU 2010-06 amended ASC 820 to require disclosures about **significant** transfers between Level 1 and Level 2 of the fair value hierarchy. ASU 2011-04 amends the disclosure requirement to include **any** transfers between Level 1 and Level 2.

- Disclosure of fair value by level for each class of assets and liabilities not measured at fair value in the statement of financial position but for which the fair value is disclosed. For example, ASC 825 requires disclosure of the fair value of certain financial instruments (e.g., loans) even though such instruments may be recognized at amortized cost in the statement of financial position. Under the new disclosure requirements, a reporting entity must disclose the instrument's level within the fair value hierarchy.

Premiums and Discounts in the Fair Value Measurement

ASU 2011-04 provides a framework for considering whether a premium or discount can be applied in a fair value measurement, the key distinguishing factor being **what** is measured (an aggregate holding position vs. an individual instrument contract or "unit of account"). The framework contains the following key principles:

- "A reporting entity shall select inputs that are consistent with the characteristics of the asset or liability that market participants would take into account in a transaction for the asset or liability . . . . In some cases, those characteristics result in the application of an adjustment, such as a premium or discount (for example, a control premium or noncontrolling interest discount)."
- "Premiums or discounts that reflect size as a characteristic of the reporting entity's **holding** (specifically, a blockage factor that adjusts the quoted price of an asset or a liability because the market's normal daily trading volume is not sufficient to absorb the **quantity held** by the entity . . .) rather than as a characteristic of the **asset or liability** (for example, a control premium when measuring the fair value of a controlling interest) are **not permitted** in a fair value measurement." [Emphasis added]
- "A fair value measurement shall not incorporate a premium or discount that is inconsistent with the unit of account in the Topic that requires or permits the fair value measurement."
- "[I]f there is a quoted price in an active market (that is, a Level 1 input) for an asset or a liability, a reporting entity shall use that quoted price without adjustment when measuring fair value, except as specified in paragraph 820-10-35-41C."

Fair Value of Instruments Classified in Shareholder's Equity

ASC 820 did not previously provide guidance on measuring the fair value of an instrument classified in shareholders' equity (e.g., equity interests related to a business combination). The ASU fills this void, specifying that a reporting entity, when determining the fair value of an equity-classified instrument, should assume that the instrument is not canceled but instead transferred to a market participant that would take on the "rights and responsibilities associated with the instrument" on the measurement date. Thus, the fair value of an instrument classified in a reporting entity's shareholders' equity is determined by using a quoted market price for a transfer of the instrument estimated "from the perspective of a **market participant that holds the identical item as an asset**" in the absence of such a price (emphasis added). The ASU lays out a model for measuring the fair value of an instrument classified in shareholders' equity that is consistent with the guidance on measuring the fair value of liabilities.

Valuation Premise and "Highest and Best Use" Concepts for Nonfinancial Assets

The ASU clarifies that the highest-and-best-use and valuation-premise concepts only apply to measuring the fair value of nonfinancial assets. The boards concluded that financial assets and liabilities "do not have alternative uses." Otherwise, the concepts themselves are largely unchanged. The ASU also eliminates from ASC 820 the use of the terms "in-exchange" and "in-use" to describe the valuation-premise concept because the wording was often confusing to constituents. Instead, the valuation-premise guidance indicates more plainly that the highest and best use of a nonfinancial asset is either on a stand-alone basis or in combination with other assets/liabilities.

Effective Date and Transition

The ASU's measurement and disclosure requirements are effective for **public entities** for reporting periods (including interim periods) beginning after December 15, 2011 (i.e., for calendar-year entities, the beginning of first quarter ended March 31, 2012), and for **nonpublic entities** for annual periods beginning after December 15, 2011. **Nonpublic entities** may early adopt the amendments for interim periods beginning after December 15, 2011.

The amendments in the ASU should be applied prospectively (i.e., no cumulative adjustment to opening retained earnings). Entities should disclose the change, if any, in valuation technique and related inputs resulting from application of the amendments and should quantify and disclose the total effect of the change, if practicable.

Industry Considerations

The ASU's measurement exception guidance on net market risk and credit exposures has been largely viewed as a "codification" of existing industry practice. For example, for measurement purposes, energy companies have historically estimated and recorded portfolio-level liquidity and credit reserves on their fair value commodity positions (which are then allocated systematically to the individual units of account for presentation and disclosure purposes). However, to qualify for use of such measurement techniques, companies should consider the criteria added by ASU 2011-04, particularly if the underlying exposures are not managed or reported in a manner consistent with the company's documented risk management strategy and policy.

Despite the ASU's elimination of the previously proposed Level 3 sensitivity/uncertainty analysis, quantitative information about Level 3 (unobservable) inputs is still required. For all Level 3 measurements, an entity must identify the valuation method used, the specific unobservable inputs used in the measurement, and numeric indications (including ranges) of the significance of such inputs. For some energy instruments that commonly (though not always) result in Level 3 classification in the industry (e.g., FTRs, load-serving requirements contracts, products in illiquid markets with limited price visibility), it may be challenging to determine how to isolate and characterize the unobservable input drivers in a way that meaningfully demonstrates the potential ranges and significance of those inputs on the resulting instrument's fair value. This may be particularly true of Level 3 instruments in which the measurement has to be "deconstructed" into linear and nonlinear (option-like) components to conform to an entity's risk management system and position management requirements (a common industry practice for load-serving power contracts) because the inputs themselves often affect the individual components in an interdependent fashion. For other commonly illiquid energy instruments (such as FTRs on illiquid paths with limited/nil ongoing auction activity), the factors driving the Level 3 classification may be entirely a function of differing available modeling approaches and unobservable inputs and not the use of differing ranges of a given input in a single model. Accordingly, entities will still need to carefully consider the potential process and systems implications of capturing, characterizing, and reporting the required quantitative information. In addition, the requirement to provide a narrative (qualitative) description of a Level 3 uncertainty analysis may in some cases have the practical effect of requiring entities to capture and process the related underlying quantitative information to ensure the narrative is reasonable.

Exposure Draft on Leases

In August 2010, the FASB and IASB issued an ED that proposed a new accounting model for both lessees and lessors. Among other aspects, the ED proposed to eliminate the bright line tests under existing U.S. GAAP, require lessees to recognize all leases and related obligations on the balance sheet (i.e., no more operating leases), and provide users of financial statements with a clearer understanding of an entity's leasing activities.

Since publication of the ED, the boards received numerous comment letters and conducted various roundtables and outreach sessions. On the basis of feedback received, the boards have made many significant changes to the proposals in the ED and therefore have decided to reexpose the proposed lease accounting guidance for public comment. Notably, the boards reaffirmed the ED's overall model in which all leases are treated as financing transactions and recognized on the balance sheet. In addition, the boards reaffirmed that lessees should apply a single model, the right-of-use model, to all leases that are within the scope of the proposed guidance, recognizing an asset for the right to use the underlying asset and a liability to make lease payments.

Scope

The ED included in its scope all leases, not only those related to property, plant, and land. This includes assets leased under a subleasing arrangement as well as PPAs, storage and transportation agreements that contain a lease (see the discussion on definition of a lease below). The boards essentially reaffirmed the scope of the ED (which was generally consistent with current accounting), with only a few minor changes. The boards decided that entities are not required to account for leases of intangibles in accordance with the proposed leasing guidance. In addition, the following are not within the scope of the leasing standard:

- Leases for the right to explore for or use minerals, oils, natural gas, and similar nonregenerative resources.
- Leases of biological assets, including timber.

Short-Term Leases

The definition of a short-term lease was retained from the ED (i.e., a lease that has a maximum possible lease term, including options to renew, of 12 months or less). However, while the ED proposed different treatment of short-term leases from a lessor versus lessee perspective, the revised proposals would result in consistent treatment of short-term leases for both parties, which is similar to today's operating lease model (i.e., under which lease assets or lease liabilities are not recognized and lease payments are recognized in profit or loss as rental income or expense on a straight-line basis over the lease term). The boards also tentatively decided to require the disclosure of rental expense associated with short-term leases in each reporting period.

Note that the above definition of lease term, which is used for determining whether a lease is "short-term," is different than that used in the measurement of leases that are other than short-term (see further discussion below).

Definition of a Lease

The ED primarily retained the guidance in EITF 01-8 and IFRIC 4 on distinguishing between a service contract and a lease contract. That guidance, which still exists under current U.S. GAAP and IFRSs, requires lease accounting if an arrangement conveys the right to control the use of a specific asset through consideration of specific criteria. However, the decision to record all leases on the balance sheet brought this issue to the forefront. Many constituents found the existing guidance cumbersome to apply and inadequate to capture the true economics of certain arrangements, particularly supply and take-or-pay contracts in which the purchaser obtains a majority of the production from a seller's asset. The boards spent considerable time redeliberating the definition of a lease and have tentatively decided to significantly change the ED's definition.

The revised proposals retain the ED's concept that a specified asset must be either explicitly (e.g., by a specific serial number) or implicitly identifiable, requiring analysis of a lessor's right to substitute assets, which is consistent with current U.S. GAAP. The boards may provide additional guidance on substitution of an asset by the lessor in the final standard. In addition, the boards tentatively decided that the underlying asset can be a physically distinct portion of a larger asset (e.g., a floor of a building) if that portion is explicitly or implicitly specified. However, a capacity portion of a larger asset that is not physically distinct (e.g., 50 percent of a pipeline) is not a specified asset.

As a result of their redeliberations, the boards decided that the concept of control would be incorporated into the lease determination analysis, in a manner similar to the concept of control in the proposed revenue recognition project. That is, a contract would convey the right to control the use of a specified asset if the customer has the ability to both direct the use and receive benefits from use of that asset. Such benefits (e.g., replacing the term "output") would include economic advantages that result directly from the use of the asset, such as renewable energy credits and secondary physical output, but would exclude income tax benefits. The payment structure related to such benefits would no longer be a determining factor in the analysis. Further, the ability to direct the use of a specified asset includes determining how, when, and in what manner the specified asset is used. If the customer can specify the output or benefit from the use of the asset but is unable to make decisions about the input or process that results in that output, the ability to specify the output would not, in and of itself, automatically mean that the customer has the ability to direct the use of the asset.

In addition, the boards tentatively decided that in situations in which a supplier directs how 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 asset is separable, the arrangement could contain a lease. However, if the use of an asset is an inseparable part of the services requested by the customer, the arrangement would not be accounted for as a lease. The staff provided indicators for use in determining whether the asset is separable (e.g., whether the asset is sold or leased separately by the supplier and whether the customer can use the asset on its own or together with other resources available to the customer).

Measurement (Lessees and Lessors)

While certain provisions apply only to lessees or lessors individually, the key concepts below apply to both parties to a lease arrangement.

Lease Term

The ED proposed that the lease term be measured as the "longest possible term that is more likely than not to occur," including options to renew. Comment letters expressed almost unanimous opposition to this measurement method. The boards agreed with many of the concerns raised in the comment letters and tentatively decided on the use of a higher threshold to define the lease term.

The proposed language would require the lease term to be the noncancelable period and would only include renewal periods in the lease term if there is a significant economic incentive for an entity to exercise an option to extend the lease. The criteria entities would use to determine whether there is a significant economic incentive are generally similar to those in current guidance on identifying when renewal periods should be included in the lease term, including contract-based, asset-based, market-based, and entity-specific factors.

The boards decided to require reassessment of the lease term when the relevant factors change so significantly that a lessee would have, or no longer have, a significant economic incentive to renew. However, changes in market rates should be considered only during the initial determination of the lease term at lease commencement, not during reassessment. Changes in lease payments that are due to a reassessment would result in a lessee's adjusting its obligation to make lease payments and its right-of-use asset. The discount rate would also be reassessed when there is a change in lease payments that is due to a change in the assessment of whether the lessee has a significant economic incentive to exercise an option to extend a lease.

Variable Lease Payments (Contingent Rents)

The ED would have required the use of a probability-weighted expected outcome approach to estimate lease payments that include contingent rentals. Many respondents to the ED objected to this proposal, noting that the approach could add significant earnings volatility and would be costly to implement.

On the basis of both this feedback and that from the staffs' outreach efforts, the boards tentatively concluded that the initial measurement would only include variable payments (1) based on an index or rate or (2) that are in-substance fixed lease payments (e.g., the lease contains disguised fixed lease payments). The boards agreed that entities should use the spot rate, rather than a forward rate, to measure variable payments related to an index or rate.

Note that the concept of in-substance fixed lease payments is different from a scenario in which rentals vary entirely on the basis of usage or sales. However, it remains to be seen how the boards will decide to articulate the in-substance (disguised) fixed payment principle in the final standard since board members appear to have different views on its application. For example, will PPA's without minimum production requirements in which contractual pricing is nonetheless based on substantive, "virtually certain" usage (i.e., wind PPAs tied to "P90" statistical production studies, or some solar PPAs) be viewed similarly to agreements with "abusive" contractual provisions lacking economic substance?

The boards also decided that entities should reassess the measurement of the variable lease payments that depend on an index or rate by using the index or rate that exists at the end of each reporting period. A lessee will recognize these changes in current income to the extent that they relate to current periods and as an adjustment to the right-of-use asset when they relate to a future period. A lessor will adjust its residual asset as variable payments are received provided the lessor had an expectation that variable payments would be received (i.e., that the rate the lessor charged the lessee reflected the impact of variable lease payments). Any payments that exceed the expectation would not result in an adjustment to the residual asset. If the rate the lessor charged the lessee did not include an expectation of variable lease payments, then the residual asset would not be adjusted upon the receipt of variable lease payments.

Purchase Options

In a departure from the ED, the boards tentatively agreed that purchase options should be accounted for similarly to options to renew. Therefore, purchase options with a "significant economic incentive to exercise" will be included in lease payments. In addition, the boards decided that the reassessment guidance for purchase options should be the same as that for lease terms.

Recognition (Lessee)

An entity would recognize the following in its financial statements for all leases other than short-term leases:

Statement	Items to Recognize
Statement of financial position	• Right-of-use asset. • Liability for the obligation to make lease payments.
Income statement	• Interest expense on the liability to make lease payments. • Amortization of the right-of-use asset. • Changes to the right-of-use asset and associated liability to make lease payments resulting from reassessment of expected amounts of index/rate-based contingent rentals, lease term, expected payments under term option penalties, and RVGs. • Impairment losses on a right-of-use asset (if necessary).

For other than short-term leases, the lease obligation is measured as the present value of lease payments over the lease term (defined above), discounted by using the lessee's incremental borrowing rate or the rate the lessor charges the lessee if such rate can be determined. The lease payments contained within this calculation must also include contingent rents meeting the revised guidance above, RVGs, purchase options, and expected payments under termination penalties between the lessee and the lessor. The right-of-use asset is equal to the amount of such liability as well as any initial direct costs incurred by the lessee.

Subsequent Measurement (Lessee)

The P&L recognition pattern under the proposed lease guidance differs significantly from that under current operating lease accounting. Rent expense would mostly be eliminated and would be replaced with amortization and interest expense. In addition, the expense in earlier years of a lease arrangement would typically be higher than the straight-line expense under current accounting. This recognition pattern is a function of treating the lease arrangement as a financing. The right-of-use asset is amortized systematically (typically, on a straight-line basis) to reflect the pattern of consumption of the expected future economic benefits. The liability is amortized by using the effective interest method, which results in higher interest expense in earlier periods.

The boards recognized this concern and at one point during the redeliberations decided that there should be two types of leases for income statement recognition purposes: finance and other-than-finance leases. They also discussed possible methods that would result in straight-line P&L recognition for leases classified as other than finance, including an annuity method of amortizing the asset or using other comprehensive income. However, after further deliberation, the boards had too many concerns about this approach, including (1) making the right cut between the two types of leases and (2) inadequate conceptual justification for different methods of P&L recognition. They therefore reversed their decision and reverted back to the proposed guidance in the ED (i.e., amortize the liability by using the interest method and amortize the right-of-use asset typically on a straight-line basis).

Each reporting period, the entity should evaluate the liability to determine whether "facts or circumstances indicate that there would be a significant change in the liability since the previous reporting period." Should there be such a change in the liability related to a changed lease term estimate, the lessee would make a corresponding adjustment to the right-of-use asset. Changes to contingent rents, RVGs, or termination penalties would be recognized through income if the change related to current or prior periods and as an adjustment to the right-of-use asset if the change related to the future periods.

Lessor Accounting

The boards have struggled to develop a single lessor model that is conceptually consistent with the lessee model and that is acceptable to both the boards and their constituents.

The ED originally proposed a dual accounting model for lessors, the application of which depended on whether the lessor retained exposure to significant risks or benefits associated with the underlying asset. If such exposure was retained, a lessor would have kept the underlying asset on its balance sheet and recognized a receivable and associated performance obligation (the "performance obligation" approach). If the lessor did not retain exposure to significant risks or benefits, the underlying asset would have been derecognized and replaced with a receivable and a residual asset, potentially resulting in profit recognition at lease commencement (the "derecognition" approach). Many respondents to the ED stated that the lessor accounting proposals needed significant further development and that lessors would need additional guidance to determine which approach to apply. In addition, many respondents believed that the current lessor accounting model was "not broken" and questioned whether the costs of implementing the new model were accompanied by an improvement in financial reporting.

After further redeliberations, the boards tentatively decided that a single lessor accounting model, the receivable and residual method, should apply to all leases. The only exceptions would be short-term leases and leases of investment property. This latter scope exception would apply regardless of whether such lessor is within the scope of the FASB's investment property entities (IPE) ED. The proposed model employs a receivable and residual approach that is similar to the derecognition approach proposed in the ED. Under initial redeliberations, this model allowed for profit recognition at lease commencement subject to a "reasonably assured" threshold. However, the boards reconsidered several aspects of the approach and ultimately reached several recent tentative decisions, including the following:

- There should be just one approach for measuring the residual asset and day-one profit; that is, different approaches based on whether profit is reasonably assured are not needed.
- The residual asset should be measured on an allocated cost basis.
- Any manufacturing profit related to the residual asset is deferred until the asset is sold or re-leased.
- The gross residual asset (not including any deferred manufacturing profit allocated to the residual asset) would be accreted by using the rate the lessor charges the lessee.

As discussed above, the boards also tentatively decided that a lessor's lease of investment property would not be included in the scope of the proposed lessor accounting model. If the lessor meets the scope requirements of the FASB's IPE ED, the lessor would account for its properties at fair value through earnings. Otherwise, such lessors would continue to recognize the underlying asset and recognize lease income over the lease term.

The boards did not discuss how rental revenue from an investment property should be recognized other than noting that the lease income would be recognized over the lease term. The IPE ED proposes that entities recognize rental revenue when lease payments are received or as the lease payments become receivable under the contractual terms of the related lease. However, in supporting memos, the FASB staff discussed retaining existing operating lease accounting, but the boards did not make a decision on this topic. The topic is likely to be discussed at a future meeting.

In addition, some FASB members acknowledged that this decision may be inconsistent with the lessee model. As discussed above, earlier in the year, the boards pursued a different income statement pattern for certain types of leases (e.g., a straight-line pattern rather than the front-end loaded model currently proposed) but ultimately rejected that model. It is uncertain whether the boards will revisit that decision, but a majority of FASB Board members expressed an interest in at least discussing the concept again in light of their decision related to investment property lessors.

Presentation and Disclosure

The ED would significantly increase the amount of required qualitative and quantitative disclosures on leases, and potentially increase disaggregation on the face of the financial statements. However, the following tentative decisions have been made.

Presentation — Lessees

The FASB and IASB tentatively decided that lease assets and liabilities should be presented separately in the statement of financial position or disclosed in the notes. In addition, the right-of-use asset should be classified with owned assets that are similar to the underlying asset associated with the lease or the right-of-use asset.

The boards also discussed the need to clarify whether the right-of-use asset is an intangible or tangible asset in response to preparer feedback. After some debate, the boards ultimately agreed that it was not necessary to clarify the nature of the asset for financial reporting purposes.

The boards also tentatively decided how cash paid that is related to various lease components should be classified in the statement of cash flows:

- Cash paid related to principal should be classified as a financing activity.
- Cash paid related to interest should be classified in accordance with applicable IFRS or U.S. GAAP requirements (e.g., operating treatment under U.S. GAAP).
- Cash paid for variable lease payments that are not included in the measurement of the lease liability should be included in operating activities.
- Cash paid for short-term leases that are excluded from the lease liability should be included in operating activities.

Presentation — Lessors

Regarding lessor presentation, the boards tentatively decided that:

- Income associated with accretion of the residual asset should be characterized as interest income.
- Lease income and expense recognized at lease commencement can be presented in the income statement either gross or net on the basis of a business model (e.g., a manufacturer would present revenue and cost of sales, while a financial institution would present a single line item).
- Lease income (including interest income) and lease expense could either be presented separately from other nonlease income and expenses of the lessor on the face of the income statement or disclosed in the notes.
- Amortization of initial direct costs should be presented as an offset to interest income.

The boards also revisited an earlier discussion about whether lease receivables should be held at fair value if the lessor intends to hold the receivables for sale. The boards tentatively decided that such receivables should not be measured at fair value. In addition, the boards decided that the derecognition requirements in IFRS 9 and ASC 860 should apply to lease receivables.

Disclosures — Lessees

The FASB and IASB voted to retain the ED's disclosure requirements but made certain editorial changes and added some new disclosures. The more significant required disclosures include:

- Reconciliation of the beginning and ending balances of the right-of-use asset and the liability to make lease payments.
- Maturity analysis of the liabilities to make lease payments.

The boards expressed some concern about the potential confusion they are creating by splitting the current concept of rent expense into several components. Therefore, they tentatively agreed to require a single disclosure detailing all various expense components (e.g., amortization expense, interest expense, short-term lease expense, and variable lease expense). However, they also agreed that this disclosure would not be combined and presented as lease expense.

Other Miscellaneous Concepts

Separation of Lease and Nonlease Elements in an Arrangement

The boards tentatively decided that an entity would be required to separate all nonlease (e.g., services, property tax) elements from the lease elements in such contracts and account for them in accordance with other GAAP. Lessors would allocate payments to lease and non-lease components in a manner consistent with the allocation methods in the revenue recognition project. Lessees would allocate payments to the lease and non-lease components on the basis of the relative observable purchase price of the individual components (or using a residual method if some but not all of the components have observable purchase prices). If there are no observable purchase prices, lessees would account for all payments as a lease.

Leveraged Leases

The ED did not provide a separate approach for lessors with leveraged leases, nor did it contain transition guidance on outstanding leveraged leases. The FASB has reaffirmed that there will be no specialized accounting for leveraged leases (i.e., the accounting for leveraged leases will be the same as that for all other leases). In addition, the after-tax yield recognition required for leveraged leases under current U.S. GAAP would be precluded. The boards also voted that leveraged lease transactions that exist upon the adoption of the proposed lease guidance will not be grandfathered. Therefore, lessors will be required to account for new and existing leveraged lease arrangements under the new standard once it becomes effective.

Build-to-Suit Leases

In build-to-suit lease arrangements, the lessee typically is involved with the construction of the asset. Although IFRSs do not contain any specific guidance on these arrangements, ASC 840 includes requirements for how to account for them. Under these requirements, the lessee is sometimes deemed the accounting owner of the leased property. The boards have tentatively decided that, like the ED, the new lease standard will not include any specific accounting requirements related to the lessee's involvement in the construction of an asset (the guidance formerly contained in EITF 97-10 will no longer exist). The boards will provide additional guidance on (1) construction costs incurred by the lessee before the commencement date and (2) prepaid rents.

In-Substance Purchases/Sales

The ED had proposed excluding, from the lease standard, contracts that (1) automatically transferred title to the underlying asset at the end of the contract or included a bargain purchase option and (2) transferred all but a trivial amount of the risks and benefits associated with the underlying asset. However, the boards tentatively decided that this guidance is not necessary and will not incorporate it into a final standard. Therefore, such contracts would continue to be accounted for under the revised leasing guidance rather than under other GAAP.

Modifications

The ED did not address how to account for modifications to lease agreements. However, the boards tentatively decided to include such guidance in the final standard — specifically, that a modification that is a substantive change would result in the termination of the existing contract and that the modified contract should be treated as a new lease. In addition, any changes that would affect the determination of whether an arrangement contains a lease (e.g., lessor substitution rights) should result in the reassessment of whether the arrangement contains a lease.

Embedded Derivatives

The ED was silent on how to account for embedded derivatives included in lease contracts. The boards decided to retain current accounting guidance requiring entities to assess whether lease contracts include embedded derivatives that should be bifurcated and accounted for in accordance with the financial instrument guidance.

Effective Date and Transition

Although the boards have not discussed a potential effective date for the final lease standard, they did discuss effective dates pertaining to the revenue project and noted that such dates would not be earlier than January 1, 2015. The boards have indicated that the revised ED is expected to be published in the first half of 2012 (for a 120-day comment period as previously indicated). A final standard is expected to be issued in 2013. This timeline makes it more likely that the effective date would be 2016, particularly given the current transition requirements, which mandate a form of retrospective adoption.

The ED had stated that all outstanding leases as of the date of initial application will be subject to the proposed lease accounting. The ED defines the date of initial application as "the beginning of the first comparative period presented in the first financial statements in which the entity applies this guidance" and requires lessees and lessors to apply the provisions of the new model by using a simplified retrospective approach as of that date.

The boards made several tentative decisions about transition requirements related to implementation of the proposed leases standard. The decisions on implementation are intended to alleviate concerns about the simplified approach proposed in the leases ED described above, which essentially treated all leases as being entered into on the adoption date and thus exacerbated the income statement effects of the new standard (i.e., for lessees it resulted in a front-end loading of expense).

The most significant decision would give both lessors and lessees an option regarding how to apply the new standard to existing leases currently classified as an operating lease. Namely, entities could use a full retrospective approach to implementation (e.g., go back to the beginning of the lease arrangement and apply the revised guidance) or use a modified retrospective approach that would attempt to simulate a full retrospective approach. Under the modified approach, a liability would still be measured as the present value of the remaining lease payments. However, the right-of-use asset would be measured as a proportionate amount of the liability, with the difference recorded as a cumulative adjustment. This is intended to provide some relief from the front-end loading of lessee expense on adoption.

In addition, to ease the burden of adoption, the boards voted to allow some transition relief from the requirements, including:

- Not requiring evaluation of initial direct costs for contracts that began before the effective date.
- Allowing the use of hindsight in the preparation of comparative information, including the determination of whether a contract is or contains a lease.

In addition, the boards tentatively decided that lessees and lessors with existing capital/finance leases (other than leveraged leases) could either carry forward the amounts recorded as of the date of initial application or apply a full retrospective approach to those leases and then prospectively apply the proposed guidance to them and to new leases.

The boards also received feedback on how a lessee should determine its incremental borrowing rate (IBR) upon adoption and whether a lessee should determine such rate on a lease-by-lease basis or by using a portfolio approach. Some constituents commented that a lease-by-lease approach would be too onerous but that a portfolio approach might be too broad and fail to take into account a portfolio with vastly different durations. The boards directed the staffs to develop wording on a principle that would settle somewhere between the two approaches (e.g., various IBR rates for groups of leases with similar durations). The boards also tentatively decided that a lessor's discount rate at transition would always be the rate the lessor charges the lessee, determined as of the date of commencement of the lease.

Industry Considerations

In light of the ED and tentative decisions reached to date, entities should also consider the following:

- Rent expense on operating leases under the current guidance will be replaced by amortization and interest expense, which will result in unequal amounts of expense in all periods (front loaded).

- Balance sheet ratios will change — specifically the debt-to-equity ratio. Entities may want to consider any regulatory impact of these changes.

- Debt covenants, such as the interest coverage ratio and debt to equity, may be affected by the changes.

- How to communicate anticipated changes to previously reported amounts to lenders and regulators as well as the implications for future SEC filings or registration statements.

- The change in the definition of a lease could significantly reduce the number of take-or-pay and supply contracts subject to lease accounting since it appears to remove the notion that an arrangement contains a lease simply because the purchaser obtains all but an insignificant amount of the output of an asset. Many PPAs (including renewable power contracts), storage, and transportation agreements that contain leases under current GAAP (EITF 01-08) may not contain leases under the revised guidance. However, constituents should continue to monitor the FASB's proposals regarding the "separability" analysis because it is unclear how the related criteria may apply to asset-backed energy arrangements in which the seller has leased or sold the asset separately or in transactions in which either counterparty could be viewed as having the sophistication required to operate the underlying asset(s).

    - The April 2011 staff agenda papers upon which the boards' current decisions were tentatively made refer to a PPA example tied to a coal-fired plant in which a tolling variation is presented (purchaser provides the coal (or fuel "input") used to produce the economic benefit (power) produced by the plant and is also involved "to some extent" in making decisions about operation of the generating units). It is clear from this example that the boards would most likely view this type of arrangement as a lease. However, it is unclear whether providing the coal (fuel input) **alone** would be a key persuasive factor on a stand-alone basis. Most within the industry have asserted that simply providing the fuel in such arrangements (without **any** ability to make decisions about plant operations) should not result in lease accounting, arguing the fuel procurement function was simply "outsourced" to the purchaser.

- On the basis of the tentative decisions reached to date, many anticipate that entities may still need enhanced processes, controls, and (in some cases) system solutions to adequately comply with the requirements of the final standard. For example, while some of the ED's original proposals regarding initial and ongoing measurement have been relaxed (notably, assessment of lease term, contingent payments, etc.), the requirement to reassess the lease term and certain other measurement elements (e.g., RVGs, term option penalties) will continue to represent a challenge for many entities. Although a higher threshold reduces some of the burden of reassessment, it still puts the onus on preparers to either perform a continual reassessment or establish a robust list of "renewal indicators." This will be particularly challenging for companies whose lease and capital investment decisions are not centralized.

- The ED would require an entity to recognize, for book purposes, new assets and liabilities that may not be recognized for tax purposes, thus resulting in a basis difference and a corresponding deferred tax asset or liability. As noted in previous editions of Deloitte's *Energy & Resources Accounting, Financial Reporting, and Tax Update*, although the lease asset and liability may initially be measured and recorded at the same amount (resulting in an entity's conclusion that no deferred tax is required), the entity is required to book the associated deferred tax on a gross basis in accordance with ASC 740-10-25-29, regardless of whether there are corresponding temporary items that net to zero.

  Entities should also note that because lease accounting for tax and book has been similar in many jurisdictions, they should specifically address the proposed change in the accounting rules when they prepare their income tax returns and supporting schedules. If it is not addressed, entities should note that the right-of-use asset may inadvertently be added to the tax basis of fixed assets and depreciated even though there is no tax basis in the asset. This may result in an entity's understating its income tax liability and potentially recording a deferred tax benefit for tax basis in a fixed asset that does not exist.

- Although the guidance related to "build-to-suit" leases formerly contained in EITF 97-10 will be superseded, lessees involved in the construction of the asset will need to consider other accounting literature for these arrangements during the construction period (e.g., consolidation guidance if the asset is included within an entity).

- ASC 810 was effective for most entities for all interim and annual reporting periods beginning after November 15, 2009, and became effective for calendar-year reporting entities on January 1, 2010. While the exception for certain operating leases previously contained in paragraph B24 of FASB Interpretation 46(R) was retained in ASC 810, going forward, the elimination of the operating lease concept under the revised leasing guidance may render this exception inapplicable. Therefore, PPAs and other arrangements previously deemed operating leases not containing variable interests on the basis of this exception may need to be reassessed to determine whether they are subject to potential consolidation and related disclosure requirements going forward. See the discussion of variable interest entities in Section 7 of Deloitte's 2010 *Energy & Resources Accounting, Financial Reporting, and Tax Update* for additional considerations on variable interest assessment of PPAs and other similar arrangements.

Exposure Drafts on Revenue Recognition

On June 24, 2010, the FASB and IASB jointly issued an ED on revenue recognition that would give entities a single comprehensive model to use in reporting information about the amount and timing of revenue resulting from contracts to provide goods or services to customers. The guidance, which would apply to any entity that enters into contracts to provide goods or services to customers, would supersede most of the current revenue recognition guidance, including many industry-specific rules that have emerged over the years.

After months of redeliberations, the boards modified the original proposals and on November 14, 2011, issued a revised ED. While, the revised ED retains the same overall model proposed in the original ED (see steps listed below), it modifies the application of those steps. Further, the boards decided to retain certain industry-specific revenue recognition guidance (see discussion below).

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 entities to follow in recognizing revenue for contracts within the proposal's scope, which are further discussed below:

- Identify the contract with a customer.

- Identify the separate performance obligations in the contract.

- Determine the transaction price.

- Allocate the transaction price to the separate performance obligations.

- Recognize revenue when (or as) the entity satisfies a performance obligation.

Scope

Like the original ED, the revised guidance applies to all contracts with customers, except for those specifically within the scope of other standards (e.g., leases within the scope of ASC 840 or derivative instruments within the scope of ASC 815). The revised ED also contains guidance similar to that in the original ED on separating and measuring contracts that are partially within the scope of multiple standards. Under that guidance, an entity would first apply the requirements of the other applicable standards if they specify how to initially separate or measure one or more parts of the contract. Otherwise, the entity would apply the separation and measurement requirements of the proposed revenue guidance.

Notably, Question 6 of the revised ED's Questions for Respondents requests feedback on a proposal that would supersede the current accounting for some transfers of nonfinancial assets (e.g., under ASC 360-20 related to sales of real estate). Specifically, the revised ED proposes that an entity apply the revenue recognition principles for the transfer of control (and the proposed measurement guidance) to the derecognition of (and the determination of gains or losses on) the transfer of a nonfinancial asset. Thus, an entity would need to use greater judgment in accounting for these types of transactions under the proposed ASU than it does under the current "rules-based" guidance in U.S. GAAP.

Identifying the Contract(s) With the Customer

Like the original ED, the revised proposal would apply to 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:

- The contract has commercial substance (that is, the risk, timing, or amount of the entity's future cash flows is expected to change as a result of the contract).
- The parties to the contract have approved the contract (in writing, orally, or in accordance with other customary business practices) and are committed to perform their respective obligations.
- The entity can identify each party's rights regarding the goods or services to be transferred.
- The entity can identify the payment terms for the goods or services to be transferred.

Notably, if both parties to a contract can unilaterally terminate the contract (before either party's performance) without penalty, a contract would not exist.

Contract Segmentation

The original ED proposed that a contract be accounted for "as two or more contracts" on the basis of a concept of price independency between contracted goods and services. This requirement was eliminated to address initial confusion among constituents that questioned the difference between contract segmentation and performance obligation separation.

Contract Combination

Departing from the original ED's proposals on price interdependency criteria, the revised ED states that an entity should combine two or more contracts that are entered into at or near the same time with the same customer (or related entities) if one or more of the following criteria are met:

- The contracts are negotiated as a package with a single commercial objective.
- The amount of consideration in one contract depends on the price or performance of the other contract.
- The goods and services promised in the contracts (or some of those goods or services) are a single performance obligation (see related discussion below on circumstances in which an entity would be required to combine a bundle of promised goods and services within a single contract).

Contract Modification

Under the original ED, contract modifications would be accounted for either (1) together with the original contract if the pricing in the new contract provided for a discount (resulting in a cumulative-effect adjustment as if the modified terms existed at contract inception) or (2) as a separate contract. Under the revised ED, however, the boards decided that an entity should account for a contract modification as a separate contract only if the modification results in (1) a separate performance obligation(s) (i.e., "distinct" goods or services) and (2) additional consideration that reflects the entity's stand-alone selling price of that separate performance obligation(s), with "appropriate adjustments" for the contract's particular circumstances taken into account.

Otherwise, an entity would evaluate the modified contract and allocate the remaining transaction price on the basis of whether the remaining performance obligations represent "distinct" goods or services that are satisfied as of a point in time or that are satisfied over time. For modifications in which the remaining goods or services are "distinct" from those that have transferred on or before the date of the modification, the remaining transaction price is allocated to the remaining performance obligations prospectively (i.e., the modification would effectively be accounted for as a termination of the old contract and the creation of a new contract).

For modifications involving nondistinct goods or services that are part of a "single performance obligation" that is partially satisfied as of the date of modification (see further discussion of performance obligation separation below), an entity would update its measure of progress toward completion, which could result in a cumulative catch-up (i.e., the modification would effectively be accounted for as if it were part of the original contract). However, if the modification to the contract is only a change in the transaction price, the modified transaction price would be reallocated to all performance obligations in the contract.

Identifying Separate Performance Obligations

The revised ED proposes that a good or service would be accounted for as a separate performance obligation if it is deemed "distinct" (i.e., 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 to it, including goods or services sold by other entities). As a practical expedient, entities may elect to treat two or more distinct performance obligations as a single performance obligation to the extent that they have the same pattern of transfer to the customer.

However, goods or services in a bundle of promised goods or services must be accounted for as a single performance obligation if both (1) the goods or services in the bundle are highly interrelated and transferring them to the customer requires that the entity also provide a significant service of integrating the goods or services into the combined item(s) for which the customer has contracted and (2) the bundle of goods or services is significantly modified or customized to fulfill the contract.

Determining the Transaction Price

The boards decided to replace the original ED's "reasonably estimated" revenue recognition constraint with a "reasonably assured" standard, clarifying that the objective for determining the transaction price is that entities should "estimate the total amount of consideration to which the entity **expects to be entitled** under the contract" (emphasis added). This estimation would be based on either (1) the probability-weighted amount or (2) the most likely amount (i.e., management's best estimate), whichever is more predictive. Notably, in a departure from the original ED, the boards decided that the transaction price should not include the effect of a customer's credit risk, which would be shown as a separate "contra-revenue" P&L line item.

Accordingly, an entity should recognize revenue at the amount of the transaction price allocated to a satisfied performance obligation unless the entity is not reasonably assured of being entitled to that amount. See the discussion on revenue recognition constraint below.

Time Value of Money

The revised ED reaffirms the boards' original proposal that the transaction price should be adjusted to reflect the time value of money when a financing component is significant to the contract. When adjusting the promised amount of consideration to reflect the time value of money, an entity's objective is to "recognize revenue at an amount that reflects what the cash selling price would have been **if the customer had paid cash for the promised goods or services at the point that they are transferred to the customer**" (emphasis added). Conversely, **if the promised amount of consideration differs from the cash selling price of the promised goods or services**, then the contract also has a financing component (i.e., interest either to or from the customer) that may be significant to the contract.

Given the subjectivity associated with determining whether a financing component is "significant" to the contract, the boards outlined factors an entity should consider in making this determination:

- Whether there is a significant timing difference between when the entity transfers the promised goods or services to the customer and when the customer pays for those goods or services.
- Whether the amount of consideration would be substantially different if the customer paid in cash promptly in accordance with typical credit terms in the industry and jurisdiction.
- The interest rate in the contract and prevailing interest rates in the relevant market.

In addition, the boards decided that when the period between the transfer of goods or services and ultimate payment is one year or less, this assessment is not required (as a practical expedient).

Allocating the Transaction Price

The revised ED states that an entity would allocate transaction pricing to each separate performance obligation in an amount that **depicts the amount of consideration to which the entity expects to be entitled** in exchange for satisfying each separate performance obligation. Mechanically, an entity would "allocate the transaction price to all separate performance obligations in proportion to the standalone selling price of the good or service underlying each of those performance obligations" as if they were sold separately at contract inception (i.e., a "relative standalone selling price" basis).

If the good or service is not sold separately, an entity is required to estimate the stand-alone selling price by using an approach that maximizes the use of observable inputs. Acceptable estimation methods noted within the revised ED may include, but are not limited to, expected cost plus a margin, adjusted market assessment, or a residual technique. The boards also decided that the residual technique should only be applied when the stand-alone selling price of a particular good or service is "highly variable or uncertain," which the revised ED notes as applicable when the related goods or services are sold at or near the same time to different customers for a "broad range of amounts" or when the entity has not yet established a price for a good or service (or the related items have not previously been sold).

Subsequent changes in the transaction price may be allocated entirely to one or more distinct performance obligations (unlike the requirement proposed in the original ED to allocate subsequent changes in the transaction price to all performance obligations) when both of the following are met:

- The contingent payment terms for a distinct good or service relate specifically to the entity's efforts to transfer that good or service (or to a specific outcome from satisfying that good or service).
- The amount allocated entirely to the distinct good or service is consistent with the overall principle that price allocation is representative of the amount the entity expects to be entitled to receive.

Recognizing Revenue When Performance Obligations Are Satisfied

The revised ED defines "control" as "the ability to direct the use of and obtain substantially all the remaining benefits from the asset" underlying the good or service, including the ability to prevent other entities from directing use or obtaining benefit from the asset. An entity first demonstrates whether control of a good or service is transferred over time. If the entity does not satisfy a performance obligation over time, it satisfies it at a point in time.

Transfers of Control Over a Period and Measurement Toward Completion

When the control of a good or service (and therefore satisfaction of the related performance obligation) is transferred over time, an entity would be required to recognize revenue over time as the goods or services are transferred to the customer. Under the revised ED, a performance obligation is considered to be transferred over time when at least one of the following criteria is met:

- The entity's performance creates or enhances an asset that the customer controls as the asset is created or enhanced (e.g., work in process).
- The entity's performance does not create an asset with alternative use to the entity and at least one of the following is met:
  - The customer simultaneously receives and consumes the benefits of the entity's performance as the entity performs.
  - Another entity would not need to substantially reperform the work the entity has completed to date if that other entity were to fulfill the remaining obligation to the customer.
  - The entity has a right to payment for performance to date and it expects to fulfill the contract as promised.

When a performance obligation is deemed to be satisfied over time, an entity recognizes revenue by measuring the obligation's progress toward completion in a manner that best depicts the transfer of goods or services to the customer. The revised ED provides specific guidance on the use and application of an output method and an input method for measuring progress toward completion.

Transfers of Control at a Point in Time

If a performance obligation does not meet the criteria to be satisfied over time, it is satisfied at a point in time. The revised ED states that indicators that control of an asset has been transferred to a customer at a point in time include, but are not limited to, the following:

- The entity has a present right to payment for the asset.
- The customer has legal title to the asset.
- The entity has transferred physical possession of the asset.
- The customer has the significant risks and rewards of ownership of the asset.
- The customer has accepted the asset.

Recognition Constraint

Finally, in response to concerns about recognizing contingent revenue without constraints, the boards decided to limit the cumulative amount of revenue recognized for a satisfied performance obligation to the amount to which the entity was reasonably assured to be entitled (specifically noting situations in which the amount of consideration is variable). An entity is not reasonably assured to be entitled to an amount allocated to a satisfied performance obligation if (1) it lacks experience with similar performance obligations or (2) its experience with similar performance obligations is not predictive of the amount of consideration to which the entity expects to be entitled. The revised ED lists indicators (not all inclusive or individually conclusive) for entities to consider in determining whether its experience or other evidence is expected to be predictive of the amount to which it is entitled. Of note, the revised ED lists factors that are outside of the entity's influence, including volatility in market prices and weather conditions as well as the length of time that exists before the uncertainty is resolved.

Other Notable Provisions

In addition to the main principles discussed above, the revised ED provides guidance on the accounting for certain costs as well as implementation guidance related to several areas. The more significant areas are highlighted below. Other areas addressed include presentation of contract assets and liabilities, principal-versus-agent considerations, licensing and rights to use, nonrefundable up-front fees, repurchase agreements, consignment arrangements, bill-and-hold arrangements, and customer acceptance. The revised ED also includes numerous examples illustrating application of its provisions.

Onerous Performance Obligations

Many respondents to the original ED were concerned about the onerous performance obligations test because entities were required to perform the test at the level of each separate performance obligation. These respondents noted that this requirement could result in accounting that is inconsistent with the economics of the contract (e.g., recognition of an onerous loss at the performance obligation level when the overall contract is profitable). During redeliberations, the boards tentatively decided that the unit of account for the onerous test would be at the contract level (i.e., the remaining performance obligations in the contract). However, because of the decision to limit the scope of the test to performance obligations **satisfied over time** for a **period greater than one year,** the revised ED proposes that the unit of account be returned to the level of each separate performance obligation.

Entities that satisfy separate performance obligations in a contract over a period greater than one year are required to determine whether the lowest costs to satisfy (or settle) those obligations are greater than the transaction price allocated to them. If so, entities would be required to recognize a liability and corresponding expense for the expected loss. This loss would be updated as of each reporting date and would be reflected in the income statement. The lowest cost of settling a performance obligation is the lower of the following amounts:

- The costs that relate directly to satisfying the performance obligation by transferring the promised goods or services (i.e., direct labor/materials, contractually chargeable amounts, costs related directly to the contract or "contract activities" (e.g., contract management/supervision)).
- The amount that the entity would pay to exit the performance obligation if the entity is permitted to do so other than by transferring the promised goods or services.

Costs of Obtaining and Fulfilling a Contract

The revised ED contains specific criteria for capitalizing certain costs associated with obtaining a contract (i.e., costs the entity expects to recover that would not have been incurred if the contract had not been obtained) and costs associated with fulfilling a contract (i.e., costs relate "directly" to fulfilling the contract (see discussion above), generate or enhance resources used to satisfy contractual performance obligations, and are expected to be recovered). As a practical expedient, qualifying costs to obtain a contract can be expensed as incurred when the expected amortization period is one year or less. Amortization of capitalized costs would occur in a manner consistent with the pattern of transfer of the goods or services to which the asset relates and, in certain circumstances, may extend beyond the original contract term with the customer (e.g., future anticipated contracts, expected renewal periods).

Disclosures

The revised ED requires entities to disclose both quantitative and qualitative information about (1) the amount, timing, and uncertainty of revenue (and related cash flows) from contracts with customers; (2) the judgment, and changes in judgment, exercised in applying the proposal's provisions; and (3) assets recognized from costs to obtain or fulfill a contract with a customer. The required disclosures, which are significantly expanded relative to those in existing revenue standards, include:

- A disaggregation of revenue into the primary categories that depict how the nature, amount, timing, and uncertainty of revenue and cash flows are affected by economic factors.
- A reconciliation of the beginning and ending balance of contract assets and liabilities.
- Certain information about performance obligations (e.g., types of goods or services, significant payment terms, typical timing of satisfying obligations, and other provisions).
- Information about onerous performance obligations (nature and amount of such performance obligations, the reasons they became onerous, the expected timing to satisfy the liability, and reconciliation of onerous balances).
- A description of the significant judgments (and changes in those judgments) that affect the amount and timing of revenue recognition.

- Information about the methods, inputs, and assumptions used to determine the transaction price and allocate amounts to performance obligations.
- Information about assets recognized from costs to obtain or fulfill a contract, including a reconciliation of the beginning and ending assets (by main category of asset).

Note that there are certain exceptions to the disclosure requirements for nonpublic entities.

Effective Date and Transition

The FASB's proposed ASU would be applied retrospectively in accordance with ASC 250, with certain optional practical expedients that can be employed during the retrospective application. The final standard's effective date would not be earlier than annual reporting periods beginning on or after January 1, 2015, for public entities, with a minimum of a one-year deferral for nonpublic entities. Early application would not be permitted for the proposed ASU; however, the IASB's proposal would permit early application.

The proposed ASU does not provide nonpublic entities with any relief from the proposed transition requirements. However, the boards noted that nonpublic entities are not specifically required by U.S. GAAP to present multiyear financial statements. This may allow certain entities to avoid some of the complexity of applying the transition guidance to multiple periods.

Industry Considerations

Accounting for Alternative Revenue Programs

The original ED would have superseded guidance in ASC 980-605 related to alternative revenue programs of rate-regulated entities. Under the original ED, certain profits that can be recognized under current U.S. GAAP before related amounts are billable to customers would not be recognizable until billable. As indicated in the revised ED, the FASB decided to (1) retain the existing requirements for alternative revenue programs currently within the scope of ASC 980-605 and (2) require that revenues from these alternative revenue programs be presented separately from rate-regulated revenues (which would be within the scope of the revenue project). In addition, the FASB identified the guidance in ASC 980 as a potential topic for future convergence standard setting with the IASB (see further discussion below).

Long-Term Bundled Power Sales Contracts

As stated above, the original ED would supersede most of the current revenue guidance, which includes ASC 980-605-25. ASC 980-605-25 provides guidance on revenue recognition for long-term power sales contracts with scheduled price changes, formula-based pricing, and contracts with both fixed and variable pricing terms. Contracts that currently qualify for lease accounting in accordance with ASC 840 will continue to be excluded from the scope of the revenue guidance.

Under the proposed guidance, an entity with a long-term power sales contract would need to identify the separate performance obligations in the contact to determine the units of accounting. Depending on the facts and circumstances of a contract, determining the separate performance obligation in these types of arrangements may be challenging. For example:

- Does bundled energy service qualify as a single "interrelated" or "customized" performance obligation? The revised ED's implementation guidance points to construction services as well as situations in which software and related customization services are provided to a customer as indicative of contracts in which the underlying goods and services are "significantly" interrelated or customized and therefore represent a single performance obligation. It may be necessary for entities to analogize to bundled energy arrangements (particularly "requirements" contracts in which the customer is not indifferent to receiving the products and services separately) that combine items like power, capacity, ancillary services, congestion management products, and the like even though the underlying deliverables may otherwise qualify as "distinct" on a stand-alone selling basis. This view may be further supported if one concludes the satisfaction of such a combined deliverable is achieved "over time" because the seller is "significantly enhancing the asset" provided to the customer because the customer controls (consumes) such asset. Of further note, concluding that the goods and services within a contract represent a single performance obligation (which is satisfied over time) has implications for other aspects of the guidance, including being subject to the onerous performance obligation test requirements (if the forward term is greater than a year), as well as potential cumulative catch-up accounting in the event such contracts are modified in the future.

- Alternatively, should delivery of kWh's over a specified period (i.e., individual forward contractual delivery periods) represent separate performance obligations on the basis of meeting the "distinct" criteria as well as control being transferred at discrete points in time (vs. a single performance obligation that is inherently satisfied "over time")? An extreme version of this view would be that **individual** kWh's delivered represent separate performance obligations. Regardless of the level of separation one concludes is reasonable, an entity may determine that under this "delivery period" separation view, combination of underlying goods or services transferred is only required (to the extent that they are deemed highly interrelated or customized) on a period-by-period basis. Entities will still need to consider appropriate price allocation to each forward delivery period in such cases, which will obviously change depending on the level of performance obligation separation (both "horizontally" over forward periods and "vertically" for each product or service transferred within a given period).

- Finally, how should renewable products (e.g., RECs, green tags) be considered given the potential lag in registration/title transfer? The same considerations about separation versus combination into a single performance obligation noted above may also apply to such products in bundled energy arrangements in which transfer is commensurate with other products. Further, will contractually agreed-upon tasks to maintain a plant be considered a separate performance obligation?

In addition, because of the long-term nature of these contracts, further challenges may arise regarding how to appropriately identify and allocate transaction pricing to the identified performance obligations. For example:

- Significant estimates in the determination of the stand-alone selling price for separate performance obligations may be required. Entities with contracts containing terms that cause variability in pricing and quantity over a contract period will need to use considerable judgment in determining whether they can reasonably estimate future prices and quantities to recognize revenue as billed or in a manner similar to current U.S. GAAP, subject to the "reasonably assured to be entitled to" constraint noted above.

- Separately, regarding forward contracts with fixed (strip) pricing associated with all forward delivery periods, it is unclear how the requirement to estimate and allocate "stand-alone" selling prices to each performance obligation should be applied, particularly if one concludes that each forward delivery represents a separate performance obligation. In such circumstances, allocating a stand-alone selling price to each forward performance obligation (based presumably on the related forward curve(s)) may be inconsistent with the constraint on allocating pricing that reflects the amount the entity expects to be entitled to (which is arguably the contracted fixed price).

- Finally, because guidance on identifying "highly variable" and "uncertain" pricing with respect to applying the residual technique of **allocating** stand-alone selling prices is different from the factors considered in **constraining** variable revenue to the "reasonably assured" amount (specifically, it excludes consideration of variability due to market volatility in the former case), entities may still be forced to estimate stand-alone selling prices for products with long-dated or otherwise illiquid or unobservable pricing on a relative basis.

In either scenario above, recognizing revenue may not be as simple as recording the billed amount over a given period. Further, under the guidance in ASC 980-605-25 (which was formerly contained in EITF 91-6 and EITF 96-17 related to contracts containing scheduled price changes or both fixed and variable terms), revenue is limited to the amounts billed when the billable amount per MWh has contractually scheduled increases. Under the revised proposals, more revenue might be recognized in the early years of such contracts. In addition, application of the proposed guidance may create additional volatility in an entity's financial reporting and result in the need for significant updates to accounting policies and processes and potentially for system enhancements.

Finally, the proposed guidance requires entities to consider whether a material financing component exists within contracts. In making such a determination, entities will need to evaluate when revenue is recognized (i.e., performance obligations satisfied) relative to the timing of customer payments. To the extent that a material financing component exists, entities will need to adjust revenue for such components and recognize interest income or expense accordingly.

Blend-and-Extend Contract Modifications

"Blend-and-extend" arrangements typically involve the extension of an existing contract term, with pricing for the remaining deliveries representing a blend of the market price for the extension period and the contract price of the "premodification" remaining deliveries. This blended price results in an equivalent contract fair value before and after modification and effectively smooths the unit price for the entire remaining delivery period (not just the add-on period).

Under the revised ED, it appears possible for one to conclude that these modifications result in either separate contracts or in the termination of the preexisting contract and creation of a new arrangement (presuming one doesn't conclude that the underlying goods and services represent a "single performance obligation" satisfied over time). However, if such modifications are viewed as a termination and subsequent creation of a new contract (or as part of the original contract in the case of single performance obligations), it is possible that previously held accounting elections could be compromised. For example, if the previous contract gave rise to an individually identified or documented hedged item in a forecasted accounting hedge relationship, or if it was previously deemed a derivative but elected under the normal purchase/normal sale exemption (or in some cases, the subject of both elections), the subsequent extinguishment may be viewed as problematic with respect to nonoccurrence of the previously documented forecasted transaction or "net settlement" of the previous contracted delivery amounts, respectively. Finally, for those who view such contracts as representing a single performance obligation satisfied over time, such modifications could also be considered to result in a cumulative catch-up adjustment to revenue.

Some in the industry have also questioned whether blend-and-extend arrangements will be considered to contain a loan to the extent that recovery of contract value is deferred through price blending over an extension period. This concern arises as a result of the guidance in the ED on the time value of money and the requirement to adjust revenue for the effect of material financing components.

At-the-Money Forward Contracts — Effect of Time Value of Money

At-the-money forward contracts, by definition, contemplate that the fixed and variable components will result in one party's making payments in early periods and the counterparty's making payments in later periods on the basis of the implicit forward rates from the yield curve. As mentioned above, under the proposed guidance, entities would be required to evaluate whether a material financing component exists within the contract. As a result, the financing component may be recognized outside of revenue, with a corresponding recognition of interest income (at the front end of the contract period) or interest expense (at the back end of the contract period). Although it appears that the guidance on the time value of money within the revised ED was meant to apply to situations in which there is a significant time lag between satisfaction of performance obligations and related customer payments, it is unclear whether the guidance would also apply to forward contracts that are at the money at inception given the prevalence of strip pricing within the industry (i.e., if the promised amount of consideration to be paid by the customer is not viewed as representative of the "cash selling price" of the related goods/services).

Exposure Draft on Accounting for Financial Instruments

In May 2010, the FASB issued an ED of a proposed ASU with the objective of improving the decision usefulness of financial instrument reporting, simplifying the related accounting requirements, and achieving convergence with the IASB. The FASB's proposed ASU contains a comprehensive new model of accounting for financial assets and financial liabilities that addresses (1) classification and measurement, (2) impairment of financial assets, and (3) hedge accounting.[17] Feedback on the ED has been extensive, causing the FASB to reexamine many aspects of the original proposal. At the same time, convergence has been elusive. In contrast to the leases and revenue recognition joint projects, the path each board took toward completing its financial instruments project diverged from the beginning. While the FASB intended to issue one comprehensive ASU, the IASB approached its project in phases. Strategy differences aside, both boards have been criticized for failing to work together on hedge accounting and classification and measurement requirements.

[17] The proposed ASU would be applied to all financial instruments with certain exceptions including (but not limited to) instruments classified in stockholders' equity, most insurance contracts, lease contracts, equity investments in consolidated subsidiaries, interests in a variable interest entity that the entity is required to consolidate, certain financial guarantee contracts, and obligations arising from pension or other retirement benefits.

Nonetheless, both boards have made plenty of progress and recent moves by the FASB and IASB raise their prospects for achieving convergence in key areas. The discussion below provides an update on the financial instruments project, in particular (1) the FASB's tentative decisions related to classification and measurement, (2) joint FASB/IASB decisions on impairment, and (3) because the FASB has not begun redeliberations on its hedge accounting proposals, feedback on the IASB's hedge accounting ED, which the FASB exposed to U.S. constituents for comment.

Classification and Measurement

The FASB's redeliberations related to the classification and measurement of financial instruments are nearly complete. The most significant areas that remain open include scope, effective date, and transition method. However, the IASB issued what was intended to be finalized requirements for the classification and measurement of financial instruments under IFRSs in November 2009 (assets) and October 2010 (liabilities). This guidance is included in IFRS 9. Recently, the IASB tentatively decided to reopen IFRS 9 and to make limited changes, opening the door for possible convergence with the FASB's model. With the FASB's redeliberations nearly complete, we can look to several key tentative decisions to understand its model for the classification and measurement of financial instruments.

Classification Categories

The FASB has tentatively agreed on the following three principal classification and measurement categories for financial instruments, thereby eliminating the remeasurement category for core deposit liabilities proposed in the original ED: (1) amortized cost, (2) fair value through other comprehensive income (FV-OCI), and (3) fair value through net income (FV-NI).In contrast to the original ED, FV-NI is not identified as the default category for instruments. None of the three categories would be a default category. Instead, financial instruments are classified into one of the three categories on the basis of an evaluation of the criteria (see discussion below) that apply to each category.

Classification Criteria

The FASB has tentatively decided that in determining the classification and measurement category for financial instruments, an entity should evaluate both the characteristics of the instrument and its business strategy for acquiring or issuing the instrument. Although an entity would assess the characteristics of each instrument individually, it would assess the business strategy at a higher level of aggregation and would not be prevented from classifying identical or similar financial instruments differently if they relate to different business activities.

The FASB has tentatively defined the characteristics criterion as follows:

> It is a *debt instrument* held or issued with all of the following characteristics:
>
> 1. It is not a financial derivative instrument subject to the guidance in [ASC 815] on derivatives and hedging.
> 2. There is an amount transferred to the debtor (issuer) at inception that will be returned to the creditor (investor) at maturity or other settlement, which is the principal amount of the contract adjusted by any discount or premium at acquisition.
> 3. The debt instrument cannot contractually be prepaid or otherwise settled in such a way that the investor would not recover substantially all of its initial investment, other than through its own choice.

Financial instruments that do not meet the characteristics criterion would be classified and measured at FV-NI. Note that this includes all equity instruments with certain exceptions, which we discuss below. Instruments that do meet the characteristics criterion would be classified and measured on the basis of an entity's business strategy. The FASB has tentatively agreed on the business strategy criteria outlined below for the three categories.

Amortized Cost

Different amortized-cost business strategy criteria apply to financial assets and financial liabilities.

For a financial asset to be classified and measured at amortized cost, it must meet the characteristics criterion and the business activity must meet **all** of the following conditions:

1. Financial assets issued or acquired for which an entity's business strategy, at origination or acquisition of the instrument, is to manage the instruments through customer financing or lending activities. These activities primarily focus on the collection of substantially all of the contractual cash flows from the borrower.

2. Financial assets for which the holder of the instrument has the ability to manage credit risk by negotiating any potential adjustment of contractual cash flows with the counterparty in the event of a potential credit loss. Sales or settlements would be limited to circumstances that would minimize losses due to deteriorating credit, or to exit a particular market for risk management purposes.

3. Financial assets that are not held for sale at acquisition.

Financial liabilities meeting the characteristics criterion would be measured at amortized cost **except** when **either** of the following business strategy conditions applies:

1. Financial liabilities for which an entity's business strategy at acquisition, issuance, or inception, is to subsequently transact at fair value.

2. Financial liabilities that are short sales.

The new business strategy criteria for the amortized cost category represent a significant change from the FASB's original ED. On the basis of these tentative decisions to date, it appears that "plain vanilla" debt instruments, including loan assets, core deposit liabilities, and an entity's own debt obligations often would qualify for amortized cost measurement.

Fair Value Through Other Comprehensive Income (FV-OCI)

Financial instruments that meet the characteristics criterion would be classified and measured at FV-OCI provided the entity's business activity meets **both** of the following conditions:

1. Financial assets issued or acquired in a business activity for which an entity's business strategy, at origination or acquisition of the assets, is to invest the cash of the entity *either* to:

    a. Maximize total return by collecting contractual cash flows or selling the asset.

    b. Manage the interest rate or liquidity risk of the entity by either holding or selling the asset.

2. Financial assets that are not held for sale at acquisition or issuance.

Unlike the original ED, the category would no longer be elective.

Fair Value Through Net Income (FV-NI)

For financial instruments to be classified and measured at FV-NI, the business activity must meet **either** of the following conditions:

1. Financial assets that are held for sale at acquisition; or

2. Financial assets that are actively managed and monitored internally on a fair value basis and do not qualify for the FV-OCI category.

As noted above, in a significant change from the FASB's original ED, FV-NI is no longer the default category and is instead limited to financial instruments in an entity's held-for-trading and held-for-sale activities.

Initial Measurement

In June 2011, the FASB unanimously voted to establish an initial measurement principle that is based on the subsequent measurement of the related financial instrument. That is, FV-NI would initially be measured at fair value and financial instruments subsequently measured at FV-OCI or amortized cost would be initially measured at the transaction price. However, entities that follow specialized industry guidance in ASC 946 (investment companies) will initially measure all financial instruments at the transaction price.

For noninvestment companies, this measurement principle results in differing treatment of transaction fees and costs depending on subsequent measurement. Such costs should be expensed when incurred for the acquisition or issuance of financial instruments initially measured at fair value (and subsequently measured at FV-NI). For the acquisition or issuance of financial instruments subsequently measured at FV-OCI or amortized cost (and therefore initially measured at the transaction price), transaction fees and costs are included in the amount initially recognized.

Reclassification and Sales

The FASB has tentatively decided that (1) reclassification between categories will not be permitted even if there is a change in an entity's business strategy and (2) subsequent sales of financial assets in the amortized cost category will not "taint" the classification of other financial assets in that category. In addition, the FASB has tentatively decided that financial assets classified and measured at amortized cost at initial recognition that are subsequently identified for sale would be measured at amortized cost subject to impairment. In this case, impairment would be recognized in net income in an amount equal to the difference between the asset's amortized cost basis and its fair value.

The FASB also addressed cases in which an entity issues or acquires a portfolio of financial assets, a portion of which will be sold at a future date while the remaining assets in the portfolio will be managed through the entity's customer financing or lending activities. However, the entity does not specifically identify the financial assets held for sale at initial recognition. In this case, the FASB's model requires an entity to classify the assets in one of the three categories, which may necessitate estimating the portion of the financial assets for which a decision has been made to sell even though specific assets are not identified at inception. This estimated portion of the portfolio held for sale would be measured at FV-NI.

Recycling

Under the FASB's tentative model, all fair value gains and losses on financial asset classified as FV-OCI would be recognized in net income (i.e., "recycled" from accumulated other comprehensive income) when such gains and losses are realized from sales or settlements or an asset is impaired.

Equity Securities

Marketable and nonmarketable equity securities would be measured at FV-NI under the FASB's tentative model. However, nonpublic entities would be offered a practicability exception, permitting them to measure nonmarketable equity securities at cost less any recognized impairment loss, adjusted for any observable price changes in orderly transactions involving identical or similar equity securities of the same issuer. The equity method of accounting also provides an exception to the requirement to measure equity securities at FV-NI.

Equity Method Accounting

The equity method of accounting, under which an equity investment is accounted for at cost with adjustments for the investor's proportionate share of the investee's net income (or net loss) after significant influence has been established, is retained for equity investments where the investor has significant influence over the investee. The FASB has proposed modifications to the scope of the equity method of accounting: the fair value option for equity method investments that exists under current U.S. GAAP would be eliminated and instead an entity would be required to classify an equity investment that otherwise qualifies for the equity method as FV-NI if the investment is held for sale when significant influence is established. The following would be determinative indicators that an equity method investment is held for sale:

- The entity has specifically identified potential exit strategies.[18]

- The entity has defined the time at which it expects to exit the investment.[19]

The FASB also made the following tentative decisions concerning the measurement of equity method investments:

- That a single-step approach would be used to evaluate the impairment of such investments, in which an entity would assess qualitative factors (impairment indicators) to determine whether an equity method investment is impaired (note that the board directed the staff to draft a proposed impairment model).

- To explicitly state in the final guidance that an entity may not reverse impairment losses previously recognized as reductions to the carrying value of equity method investments.

Hybrid Financial Instruments

The FASB tentatively decided to retain the current bifurcation requirements in ASC 815-15 for embedded derivatives in hybrid financial instruments. Therefore, in a manner consistent with current U.S. GAAP, an embedded feature that meets the bifurcation requirements in ASC 815-15 would need to be bifurcated and accounted for separately as a derivative instrument. This represents a significant change from the original ED, under which an entity would have been required to account for a hybrid financial instrument with such an embedded feature as FV-NI in its entirety. However, the FASB also tentatively decided to allow entities the **option** of electing (at initial recognition) to measure hybrid financial instruments at FV-NI in their entirety once the entity has determined that an embedded derivative exists that would otherwise require bifurcation.

Certain Convertible Debt Instruments

The FASB reached a tentative decision on how an issuer should account for certain convertible debt instruments in which the conversion feature (1) qualifies for the scope exception in ASC 815-10-15-74(a) and (2) meets the requirements in ASC 470-20-25-10 through 25-16 related to a nonbeneficial conversion feature. Specifically, these instruments include convertible instruments (1) that do not contain embedded derivative instruments because they meet the scope exception in ASC 815-15 (i.e., they are indexed to an entity's own stock and classified in shareholders' equity) and (2) for which no portion of the proceeds (from issuance) is allocated to the conversion feature. The FASB concluded that such instruments should be measured at amortized cost in their entirety.

Presentation

In August 2011, the FASB made tentative decisions on presentation of financial instruments under which public entities (future deliberations on the following requirements for nonpublic entities are yet to come) would be required to:

- Present fair value parenthetically on the face of the balance sheet for assets and liabilities measured at amortized cost, excluding core deposit liabilities (short-term receivables and payables would be exempted from this requirement).

- Determine these fair value measurements in accordance with ASC 820.

- Disclose a present value amount for core deposit liabilities (the board requested the staff to further develop this present value measurement attribute and will discuss this issue at a future meeting).

The FASB also tentatively decided to require all entities (public and nonpublic) to, among other things:

- Separately present financial assets and financial liabilities on the balance sheet by classification and measurement category.

[18] However, an entity would not be required to determine the specific strategy to exit the investment.

[19] The time at which an entity expects to exit the investment may be based on a range of dates or the occurrence of a contingent event such as the achievement of specific milestones or investment objectives.

- Present amortized cost parenthetically on the face of the balance sheet for an entity's own debt measured at fair value.
- Present in net income an aggregate amount of realized and unrealized gains or losses for financial assets measured at FV-NI and, similarly, for financial liabilities measured at FV-NI.
- Separately present cumulative credit losses on the face of the balance sheet for financial assets measured at amortized cost.
- Separately present the following items in net income for financial assets and liabilities measured at amortized cost or for financial assets measured at fair value through other comprehensive income:
  - Current-period interest income (financial assets) and expense (financial liabilities).
  - Credit losses for the current period (financial assets).
  - Realized gains or losses (both financial assets and liabilities).

Disclosure

As a result of the FASB's December 21, 2010, board meeting, the FASB staff began (1) developing a package of potential disclosure requirements for risks associated with financial instruments and (2) conducting related research and outreach activities with users, preparers, and regulators regarding usefulness, cost, and effort of potential disclosures. In June 2011, the FASB tentatively decided to improve disclosures about liquidity risk and interest rate risk rather than to require disclosures about **all** risks.

In September 2011, the FASB decided to require all entities (both financial institutions and nonfinancial institutions, public and nonpublic) to provide disclosures about liquidity risk (discussed further below) and to require only financial institutions to provide disclosures about interest rate risk. The proposed disclosures would be required for interim and annual periods, although nonpublic, nonfinancial entities would only be required to provide the liquidity risk disclosures for annual reporting periods. The FASB's September 7, 2011, Action Alert describes the proposed disclosure requirements as follows:

> **Qualitative**
>
> For interest rate risk and liquidity risk arising from financial instruments, an entity would disclose the following:
>
> 1. The exposure to risks and how they arise
> 2. Its objectives, policies, and processes for managing the risks and the methods used to measure the risks
> 3. Any changes in item (1) or (2) from the previous period and the reasons for the changes.
>
> **Liquidity Risk—Quantitative**
>
> 1. All entities would provide disclosure about their available liquid funds, which includes unencumbered cash and high-quality liquid assets, and borrowing availability such as lines of credit. This disclosure would include a discussion about the effect of regulatory, tax, legal, and other restrictions that could limit the transferability of funds among entities in the consolidated group, for example, between the parent company and subsidiaries.
> 2. *Financial institutions* would provide a tabular disclosure based on expected maturities of classes of financial assets and financial liabilities. Financial instruments that are classified at fair value through net income, with the exception of derivatives, would not be placed in maturity buckets and would only show the total carrying amount. The term expected maturity relates to contractual settlement of the instrument, not the entity's expected timing of the sale of the instrument. The table would include the entity's off-balance-sheet commitments, for example, loan commitments and lines of credit.
> 3. Nonfinancial entities would provide a tabular disclosure of their undiscounted cash obligations, including off-balance-sheet obligations.

Next Steps

The FASB's redeliberations of the classification and measurement of financial instruments are nearly complete. However, the Board still needs to redeliberate certain issues (e.g., the final standard's scope, effective date, and transition approach). The FASB has shared the principal elements of its tentative model with the IASB. We expect the FASB to issue an ED on classification and measurement in the first half of 2012.

Impairment

In January 2011, the boards jointly issued a supplementary document for comment as a follow-up to the FASB's original ED and the IASB's November 2009 ED on credit impairment. The supplementary document would replace the incurred loss impairment models under U.S. GAAP and IFRSs with an expected loss impairment model. However, the supplementary document only focuses on when and how credit impairment should be recognized; it does not address other aspects of the accounting for impairment of financial assets. From a U.S. GAAP perspective, the proposals in the supplementary document would apply to loans and debt instruments under U.S. GAAP that are managed on an "open" portfolio basis provided they are not measured at fair value with changes in fair value recognized in net income.

On the basis of feedback received and the boards' related working group efforts, in June 2011 the boards tentatively agreed to develop a new impairment model in which loans subject to impairment accounting would be split into three buckets that determine the amount and timing of credit losses to be recognized as follows:

- *Bucket 1* — Comprises assets that, while not affected by observable events that directly relate to possible future defaults, are affected by macroeconomic events that may change expected credit losses. The allowance balance for this bucket comprises lifetime expected losses on the portion of financial assets for which a loss event is expected over the next 12 months.
- *Bucket 2* — Comprises assets that are affected by the occurrence of observable events that directly relate to future defaults; however, the default is not specifically identifiable for an individual asset. The allowance balance for this bucket is determined on the basis of a portfolio-level calculation of the full lifetime expected losses.
- *Bucket 3* — Comprises assets to which expected or incurred losses can be specifically attributed. The allowance balance is the full lifetime expected losses for the loans in this bucket.

Under the proposed relative credit risk approach to "bucketing" debt instruments, originated and purchased assets would be initially classified in Bucket 1 even if they are of lower credit quality (e.g., subprime loans) and would be subsequently transferred into Bucket 2 or 3 when there has been a more than insignificant deterioration in credit quality since initial recognition and it is at least reasonably possible that the contractual cash flows may not be fully recoverable. In addition, probability of default should be the primary factor that entities consider in determining when to transfer financial assets between buckets. However, entities should not ignore information indicating the potential for loss (e.g., "loss given default" information).

To date, the discussions of the expected-loss impairment model have focused on loans; however, the impairment model will also apply to debt securities. Under the expected-loss impairment model, there will be no bright lines for evaluating a debt security for credit deterioration when its fair value is less than its cost basis; rather, an entity should consider indicators when applying the model to debt securities. Further, with respect to commercial and consumer loans, the impairment model will not include a bright line indicating that meaningful credit deterioration has occurred on the basis of predetermined factors (e.g., days delinquent, achieving a particular credit risk rating).

Next Steps

The boards are continuing to develop the three-bucket approach. The IASB's work plan indicates that an ED or review draft of a standard on impairment will be published in the second quarter of 2012. It remains to be seen when and how the boards will address impairment beyond open loan portfolios, so the full implications to the energy industry of these deliberations are far from clear at this point.

Hedge Accounting

Hedge accounting is similar to the classification and measurement portion of the financial instruments project in that the FASB and IASB have taken differing approaches and paths toward refining their respective standards. After issuing its hedge accounting proposals in May of last year, the FASB released a discussion paper in February 2011 to obtain feedback on the IASB's hedge accounting ED. The FASB intends to consider the feedback received on the IASB's proposal during its redeliberations of the hedge accounting component of the financial instruments project; however, at this time, the FASB has yet to formalize its official timeline for formal redeliberations on hedge accounting.

Conversely, the IASB has moved relatively quickly with its proposals since issuing its ED in December of 2010. The feedback received from comment letters and during outreach activities indicates that constituents generally supported the overall hedging proposal. For example, constituents strongly supported (1) the proposed objective of hedge accounting, which aligns hedge accounting with an entity's risk management activities; (2) the proposed elimination of the 80 percent to 125 percent bright-line hedge effectiveness threshold to qualify for hedge accounting; and (3) permitting risk components of nonfinancial items to be hedgeable items. However, while constituents were broadly supportive of the principles of the model, they also noted that they would need additional implementation guidance to apply the proposals. Constituents have also requested that macro hedging be addressed because it will be an important part of the final standard on hedge accounting.

Accordingly, in its redeliberations throughout this year, the IASB largely focused on making targeted clarifications and refinements to its broader proposals. The paragraphs below highlight some of the more significant aspects of the IASB's ED that were addressed during redeliberations.

Objective of Hedge Accounting

A majority of the respondents expressed strong support for the proposed principle, which aligns the hedge accounting requirements with an entity's risk management activities. However, respondents also had several concerns, including the fact that the term "risk management" is not defined in the proposal, which could lead to diversity in practice.

Hedged Items

Most respondents strongly support the proposal to permit designation of (1) risk components (of both financial and nonfinancial items), (2) aggregate exposures (i.e., a combination of an exposure and a derivative), (3) certain net positions, and (4) certain layer components as hedged items since to do so would better reflect entities' different risk management strategies. However, among other concerns, many respondents requested more implementation guidance on noncontractually-specified risk components of nonfinancial items, indicating such guidance would help them identify a risk component and reduce diversity in practice. During redeliberations, the IASB confirmed these proposals, and in response to constituents, decided to include additional application guidance and illustrative examples. The IASB has indicated that such guidance will include various commodity/nonfinancial risk examples.

Time Value of Options

Most respondents supported the need to address the accounting for the time value of options and generally agree that this time value is a cost associated with a hedging relationship. However, many respondents believe that the accounting proposed for the time value of options by the IASB would significantly add to the complexity of hedge accounting. During redeliberations the IASB tentatively decided to retain the ED's proposed accounting model (i.e., the "insurance premium view"), but also decided to provide additional guidance on differentiating between transaction-related and time-related hedged items and the amortization period used for the time value component.

Hedge Effectiveness

Most respondents supported the elimination of the 80 percent to 125 percent effectiveness threshold to qualify for hedge accounting. Respondents' feedback on hedge effectiveness included the following:

- Some requested more implementation guidance on the new principles-based approach for assessing hedge effectiveness, including application of the term "other than accidental offsetting."

- Some believed that the proposed effectiveness requirements were not stringent enough to prevent inappropriate hedges from qualifying for hedge accounting. Others suggested that the final guidance should introduce the notion of "reasonable" effectiveness without stipulating a numerical threshold.

Accordingly, in response to constituent feedback, the IASB's redeliberations focused on clarifying the criteria that must be met to qualify for hedge accounting. Many of the IASB's tentative decisions now tend to reflect a notion of "reasonable effectiveness." For example, the IASB removed the effectiveness threshold term "other than accidental offsetting" and specified its intended principle through the two following criteria:

- There must be an economic relationship between the hedged item and the hedging instrument which gives rise to offset.
- The effect of credit risk cannot dominate the value changes arising from that economic relationship.

Further, the IASB decided to address confusion that had arisen regarding the ED's hedge qualification criterion that a hedge must meet "the objective of the hedge effectiveness assessment," described in the ED with the terms "unbiased" and "minimize expected hedge ineffectiveness." This language gave some respondents the impression that the initial proposal had built in an expectation of "optimal" effectiveness (i.e., no/nil ineffectiveness). Instead, the IASB attempted to clarify these concepts by requiring that the designation of a hedging relationship should be based on a hedge ratio that is based on actual quantities of the item being hedged and the hedging instrument.

The board also included an anti-abuse provision that prohibits an entity from designating a hedge ratio that would reflect an imbalance in the weightings of the hedged item and hedging instrument that would create ineffectiveness to achieve an accounting outcome inconsistent with the purpose of hedge accounting. Thus, for example, an entity would be prohibited from using a hedge ratio for a cash flow hedge that was specifically designed to result in an under-hedge and result in hedge ineffectiveness not being recognized as a result of the "lower of" test for cash flow hedges.

Rebalancing

Respondents expressed mixed views regarding rebalancing of a hedging relationship. Generally, respondents supported rebalancing because it reflects an entity's risk management strategy and avoids the current necessity of formal dedesignation and redesignation (along with the attendant documentation requirements, the potential impact on ongoing effectiveness, etc.). However, others were concerned that requiring rebalancing might still result in an accounting exercise rather than reflect risk management, particularly when considered in light of previous concerns that an implicit expectation of "optimal effectiveness" may have been embedded in the IASB's proposals. Similarly, some believed that rebalancing should be optional rather than mandatory.

To respond to this feedback and to reflect the clarifications it made to the hedge qualification criteria, the IASB modified its rebalancing requirements. Specifically, the board determined that an entity should rebalance a hedging relationship in either of the following circumstances:

- The "hedge ratio used for risk management purposes changes" (i.e., the hedge ratio based on actual quantities used).
- "[R]ebalancing was required to prevent the hedge ratio resulting in an imbalance that would create hedge ineffectiveness in order to achieve an outcome that is inconsistent with the purpose of hedge accounting."

Discontinuation

Most respondents agree that hedge accounting should be discontinued prospectively when a hedging relationship ceases to meet the hedge accounting criteria. However, many believe that an entity's decision to discontinue hedge accounting should not be limited to situations in which the hedge ceases to meet these criteria but rather that it should be elective. This is particularly true of the energy and other commodity-driven industries in which voluntary reductions or changes in hedge levels occur frequently as a result of a variety of reasons that many within the industry view as consistent with an entity's risk management strategies (e.g., replacement and perfection of previous proxy hedges with more liquid commodities, instrument types, and seasonal products as they become available; demand shaping; risk "selection" vs. simplistic risk "reduction"). Elective dedesignation is currently allowed under U.S. GAAP and IFRSs, and many question the boards' desire to eliminate this ability.

Despite constituents' concerns, during redeliberations the IASB reconfirmed its decision not to allow voluntary discontinuation. Specifically, the board cited concerns that allowing a hedging relationship that satisfies the qualifying hedge criteria to cease when an entity's risk management objective has not changed "would result in a misalignment with risk management and hence be inconsistent with the overall objective of the new hedge accounting model." The IASB did indicate that it would provide additional guidance in its final standard on the difference between an entity's overall risk management strategy and its risk management objective for a particular hedging relationship. A risk management strategy represents the highest level for which an entity manages risk, while a risk management objective pertains to a particular hedging relationship. The final standard is expected to include examples of how these two concepts interact.

Fair Value Hedge Mechanics

Most respondents disagreed with the proposal to defer changes in the fair value of the hedged item and the hedging instrument in other comprehensive income since they believe there is no conceptual basis for such deferral. In addition, most respondents did not agree with reporting changes in fair value of the hedged item as a separate line item on the balance sheet. During redeliberations, the IASB tentatively decided that fair value changes of the hedging instrument and the hedged item would be taken immediately to profit or loss as is currently required by IAS 39, with additional disclosure required in the notes to the financial statements of the extent of risk management activities and offsetting achieved by hedges.

Next Steps

The FASB has not yet indicated a specific timeline for when it plans to start redeliberating the hedge accounting component of the financial instruments project. The Board continues to focus its attention on the classification and measurement and impairment components of the project, although it has indicated that it expects to consider the feedback on the IASB's hedge accounting ED when it continues its redeliberations.

The IASB completed its deliberations on its general hedge accounting model in September 2011. Before finalizing the proposed amendments to IFRS 9, the IASB will post a staff draft of its final amendments to its Web site (this is expected in early 2012). Although this step does not constitute a formal reexposure of its decisions, it will give constituents a final opportunity to review the proposals and provide feedback to the IASB during the posting period, which is expected to be 90 days. Once the posting period ends, the IASB plans to proceed with finalizing the general hedge accounting project.

As the IASB continues to move toward the finalization of its general hedge accounting model, it is also addressing constituent feedback through the commencement of its separate project to improve the current guidance in IAS 39 on macro hedge accounting. The macro hedging project will focus on risk management strategies pertaining to open portfolios. The IASB is currently expecting to issue an ED on its proposals in the third quarter of 2012.

Industry Considerations

The FASB's tentative decisions to date associated with classification and measurement should alleviate many of the initial concerns of potentially having to record an entity's own debt at fair value. However, the FASB's tentative decision to require parenthetical presentation of fair value on the basis of an exit price for financial liabilities measured at amortized cost (excluding core deposits), but not to provide a practicability exception, is a change from existing U.S. GAAP. ASC 825-10-50-10(a) requires an entity to disclose "the fair value of financial instruments for which it is practicable to estimate that value."

Note that some entities use an entry price, instead of the exit price in ASC 820, to comply with this existing disclosure requirement. Such a measurement practice will not be acceptable to comply with the new parenthetical presentation requirement described above. The guidance often cited to support existing disclosure practice is Example 1 from the implementation guidance in ASC 825-10-55-3, which provides a sample disclosure for a hypothetical bank and states, in part, "The fair value of other types of loans is estimated by discounting the future cash flows using the current rates at which similar loans would be made to borrowers with similar credit ratings and for the same remaining maturities." In short, this is a description of the transaction price associated with a loan issuance occurring at the time of valuation or an entry price. When introducing its presentation questions to the Board, the FASB staff noted that some preparers and auditors had operational concerns about presenting loans at fair value on the face of the balance sheet, including concerns that entities may need more time, and may incur additional costs, when moving from an entry price calculation to an exit price calculation. Despite these concerns, the board tentatively decided that an exit price should be used to comply with the proposed presentation requirements.

Some within the industry (particularly those with fully or partially deregulated NDT) raised concerns about the FASB's originally proposed classification and measurement criteria with respect to NDTs. Specifically, the ED's proposals could result in certain investments within these funds being treated as FV-NI because equities are treated as FV-NI per the ED and other instruments within these funds (including debt securities) are subject to "churn" at the discretion of the fund manager (despite their purpose and restricted nature, like pension funds). It remains to be seen how NDTs will fit within the final revised cash flow characteristics and business strategy criteria given that (1) the current amortized cost and FV-OCI criteria are limited to "debt instruments," (2) FV-NI will be required for equity securities (which many NDT funds hold), (3) FV-OCI currently prohibits "held for sale" investments (note that NDT investments are typically classified as "available for sale" today, a classification category that does not imply "holding" with the specific intent to sell/trade but that did not carry forward in the Board's proposals), and (4) FV-NI specifically includes "held for sale" instruments. Note that for NDTs subject to regulatory accounting treatment under ASC 980, changes in fair value that would otherwise be reported in earnings under the FV-NI model should continue to be reported as a change in the related regulatory asset or liability on the balance sheet.

Finally, companies should continue to follow the progress regarding impairment, particularly that related to financial assets yet to be contemplated (e.g., trade receivables) and measurement of credit losses, and comment as appropriate if this aspect of the standard is reexposed. Companies should also closely monitor the developments of the FASB's deliberations on the IASB's hedge accounting proposals once commenced, particularly those related to nonfinancial component hedging, application of effectiveness assessment criteria, rebalancing, and voluntary dedesignation (discontinuation). Note that on the basis of the IASB's redeliberations during the summer of 2011, it is possible that some of the initial concerns identified by industry participants with respect to some of these topics may be alleviated in the final IASB standard given the examples and concepts discussed within the IASB staff's relevant agenda papers used in redeliberations. For example, certain common industry reasons for voluntarily discontinuing commodity accounting hedges today may fit within the notion of changing the entity's hedging "strategy" (which would require dedesignation under the IASB's proposals). Further, the thinking expressed by the IASB and its staff in redeliberating the topic of nonfinancial component hedging may favorably address some initial industry concerns on how to interpret the "separately identifiable" and "reliably measurable" criteria for noncontractually specified risk components (e.g., ability to reference relevant market pricing practices for given commodities, treatment of negative spreads/basis).

Accounting Standards Update on Offsetting

In December 2011, the FASB issued ASU 2011-11, which finalized the proposals outlined in the Board's January 2011 ED on balance sheet offsetting of financial assets and liabilities. On the same day the FASB issued ASU 2011-11, the IASB made similar amendments to IFRS 7 and also clarified certain aspects of IAS 32.

The ED proposed the following (for all recognized financial assets and financial liabilities, including derivative instruments (financial and nonfinancial)).

- **Required** net presentation (not elective) of financial assets and liabilities on the statement of financial position if entities (1) have a legally enforceable, **unconditional right** to offset these assets and liabilities and (2) intend to **settle net or simultaneously**.
- Retrospective application.
- Expanded disclosures about rights of setoff and similar arrangements (e.g., collateral agreements) associated with an entity's financial assets and liabilities.

U.S. preparers were generally supportive of eliminating the current elective approach under U.S. GAAP to achieve greater convergence and reduce diversity in practice, but many opposed the "unconditional" and "simultaneous" netting criteria requirements.

In June 2011, the boards reached different decisions about which accounting offsetting model should be used. They decided that the best approach going forward was to focus on converging disclosure requirements to address differences between methods. Accepting the boards' inability to agree on a converged accounting model, the IASB later voted at a separate meeting to retain the existing offsetting requirements in IAS 32 instead of further pursuing the offsetting model proposed in the joint ED. Similarly, the FASB voted to retain the existing derivative and nonderivative offsetting guidance (ASC 210 and ASC 815) in U.S. GAAP, subject to new disclosure requirements discussed below.

The boards retained their proposed objective for requiring offsetting disclosures; namely, that an entity should disclose information about its rights of setoff and related arrangements (such as collateral arrangements) associated with its financial assets and financial liabilities to enable users of its financial statements to understand the effect of those rights and arrangements on the entity's financial position.

Scope

As noted in the ASU, the new disclosure requirements apply to all entities with either of the following:

- Recognized financial instruments and derivative instruments that are offset in accordance with either ASC 210-20-455 or ASC 815-10-45 (i.e., offset in accordance with the general offsetting model or the offsetting models for repurchase and reverse repurchase agreements and derivative arrangements and related cash collateral payables or receivables).
- Recognized financial instruments and derivative instruments that are subject to an enforceable master netting arrangement or similar agreement, irrespective of whether they are offset in accordance with either ASC 210-20-45 or ASC 815-10-45.

Examples of a "similar agreement" include (1) derivative clearing agreements, (2) global master repurchase agreements, and (3) global master securities lending agreements as well as any related rights to financial collateral. Financial instruments and transactions that would fall within the scope of the disclosure requirements typically would include derivatives, repurchase and reverse repurchase agreements, and securities borrowing or lending agreements, but they would exclude (1) "[l]oans and customer deposits [held] at the same [financial] institution (unless they are offset in the statement of financial position)" and (2) "[f]inancial instruments that are only subject to a collateral agreement."

Disclosure Requirements

Under the ASU, entities will be required to disclose the following information:

> a. The gross amounts of recognized financial assets and financial liabilities.
>
> b. The amounts offset in accordance with the guidance in [ASC] 210-20-45 and 815-10-45 to determine the net amounts presented in the statement of financial position.
>
> c. The net amount reported in the statement of financial position.
>
> d. The amounts subject to an enforceable master netting arrangement or similar agreement not otherwise included in (b):
>
> 1. The amounts related to recognized financial instruments and other derivative instruments that either:
>
> i. Management makes an accounting policy election not to offset.
>
> ii. Do not meet some or all of the guidance in either [ASC] 210-20-45 or [ASC] 815-10-45.
>
> 2. The amounts related to financial collateral (including cash collateral).
>
> e. The net amount after deducting the amounts in (d) from the amounts in (c).

To avoid the masking of undercollateralized positions by overcollateralized positions, the total amount that can be disclosed for a particular instrument in (d) above is limited to the amount that is disclosed in (c). In other words, collateral obtained (or posted) for a given instrument would only be disclosed in an amount up to 100 percent of the instrument's net amount presented in the balance sheet. In addition, for each type of right of setoff disclosed in (d), an entity must also provide a narrative description of the nature of that right, such as how and when that right can be exercised.

The ASU provides two options for how entities may group the quantitative information disclosed for items (c) through (e) above. An entity may group information by type of instrument (e.g., derivatives and repurchase agreements and reverse repurchase agreements). Conversely, the entity may group the disclosures by counterparty. If the entity elects the counterparty option, it does not need to identify the names of specific counterparties; however, it should disclose individually significant counterparties separately, and it may group all other counterparties into a single amount. Entities making this election still must present the information in items (a) through (c) by type of instrument.

The ASU emphasizes the importance of reconciling the net amounts disclosed in item (c) to "the individual line item amount(s) presented in the statement of financial position." Such reconciliation must be provided regardless of the level of aggregation or disaggregation used for the disclosures.

Effective Date and Transition

For all entities, the ASU is effective for fiscal years beginning on or after January 1, 2013, and interim periods within those annual periods. The guidance must be applied retrospectively for any period presented that begins before an entity's date of initial application.

Industry Considerations

While the FASB's decision to retain existing U.S. GAAP offsetting guidance means that entities will not be required to gross up previously netted amounts in accordance with the ED's original proposals, entities will still need to comply with the revised disclosure requirements commencing in 2013. These disclosures may be easier to comply with for U.S. entities that currently elect to net derivative assets, liabilities, and related fair value collateral payable/receivable amounts under ASC 815-10-45 (formerly Interpretation 39) because items (c) and (d) above largely reflect such netting under current guidance (i.e., including the effect of contractual and related fair value collateral amounts netted under conditional MNAs and similar agreements) and because the required beginning gross amounts should already be available as a result of the existing fair value hierarchy and derivative balance sheet disclosure requirements under ASC 820 and 815. However, U.S. entities that do not elect to net under ASC 815-10-45 now will effectively need to implement processes to gather this information to comply with the above disclosure requirements.

Exposure Drafts on Disclosures About Certain Loss Contingencies

In June 2008, the FASB issued an ED on disclosures related to certain loss contingencies (the "2008 ED"). The FASB undertook the project to address financial statement users' concerns that Statement 5 (later codified as ASC 450-202) did not require entities to provide sufficient information in a timely manner about certain remote contingencies or loss contingencies in situations in which the loss amount could not be reasonably estimated. The 2008 ED would have significantly expanded the amount of information available to users by requiring entities to disclose certain remote loss contingencies and, for any loss contingency (including certain remote contingencies), the claim or assessment amount (or the entity's best estimate of its maximum exposure to loss if there was no claim or assessment amount).

Constituents expressed numerous concerns about the 2008 ED, including the difficulty preparers would have making reliable estimates of their exposure to loss, legal concerns about the prejudicial nature of the required disclosures, and auditors' concerns about the reasonable level of assurance that could be obtained for some of the proposed disclosures. Separately, during the 2010 AICPA Conference, and at a January 2011 meeting of the SEC's Division of Corporation Finance with the New York City Bar, the SEC has stressed a renewed focus on compliance with ASC 450's existing disclosure requirements for litigation contingencies.

In response to these concerns, in July 2010 the FASB issued an ED of a proposed ASU on loss contingency disclosures that would:

- Expand the scope of loss contingencies subject to disclosure to include certain "special remote" contingencies (generally the same scope as the 2008 ED).
- Increase the quantitative and qualitative disclosures entities must provide to enable users to assess the nature, potential magnitude, and potential timing (if known) of loss contingencies.
    - Certain aspects of the proposed ASU differ from the 2008 ED; however, the new proposal's disclosures are similarly extensive. Examples of the proposed requirements include disclosure of amounts accrued, possible losses or ranges of loss for contingencies that are probable or reasonably possible, publicly available and nonprivileged information to help a user understand the nature and potential magnitude of loss for all contingencies, certain information about possible insurance recoveries, and anticipated timing and next steps (if known).
- For public entities, require a tabular reconciliation of changes in amounts recognized for loss contingencies, by class of contingency (generally the same as proposed in the 2008 ED, except for a class disaggregation requirement and limitation to public entities).

Notably, while the 2008 ED included a limited prejudicial exemption, the proposed ASU does not.

Reactions and Next Steps

The proposed ASU addressed some but not all of the concerns raised by constituents in their comments on the 2008 ED. In reassessing the project, the FASB determined its priority to be lower than its other convergence projects (i.e., leases, revenue recognition, and financial Instruments); therefore, further action is not expected in the near term. However, before beginning redeliberations, the FASB directed its staff to (1) understand efforts made by the SEC and PCAOB to improve compliance with existing disclosure requirements in ASC 450-20-31 and (2) review 2010 Form 10-K filings for calendar-year-end reporting entities to determine whether those efforts resulted in improved disclosures. We can therefore expect the FASB's ongoing efforts in this area to be influenced by the perceived level of compliance with existing disclosure requirements.

Emissions Trading Schemes

Background

Trading schemes to reduce greenhouse gas emissions have expanded rapidly in recent years at the state, national, and international levels. Cap-and-trade programs are a common emission allowance approach in which a government (or governmental agency) typically issues tradable rights (allowances) to emit pollutants to participating entities. Participants may buy and sell allowances with others, and some liquid markets have developed to facilitate this trading activity. At the end of a compliance period, participants are required to deliver allowances equal to their actual emissions, and they may be required to pay a fine or suffer other penalties for emissions in excess of remitted allowances.

Many emissions trading schemes give entities added flexibility in fulfilling part of their obligation by allowing them to remit project-based certificates. A project might involve, for example, upgrading equipment at a foreign plant (outside the jurisdiction of the emissions scheme) to make it more efficient. Once a project is approved, validated, registered, and verified, certificates are issued that may be traded or remitted in lieu of standard scheme allowances.

Another type of market program that continues to gain prominence aims to reduce greenhouse gas emissions by requiring electricity producers to remit a minimum number of RECs annually (often based on a required percentage of load/customers served from renewable energy sources). The certificates are granted to entities that generate electricity from designated renewable energy sources, and they may be bought and sold. To meet the minimum requirement, an energy producer may generate RECs itself, buy them on the open market, or pay a fine for its shortfall of RECs remitted.

History of Accounting Guidance and Related Developments

Domestic

In November 2003, the EITF released Issue 03-14, which attempted to address the accounting for emissions allowances However, after one meeting, the Task Force decided to remove the Issue from its agenda. After FASB Statement 153 was issued in December 2004, certain narrow application questions arose in practice about whether vintage year swaps should be accounted for at fair value or on the basis of the recorded amount. After initially recommending a narrow scope project, on October 12, 2006, the TA&I Committee instructed the FASB staff to prepare an agenda request for the Board to consider whether to address the accounting for emission allowances in a comprehensive manner.

The guidance in the FERC Uniform System of Accounts is the only accounting guidance available in the United States that explicitly addresses emissions allowances. Some U.S. entities generally account for emission allowances by using an inventory model, recording the initial recognition amount in a manner similar to that required by FERC regulations, under which entities must recognize emission allowances on a historical cost basis (which may be zero if allocated free of charge to a participating entity) and must expense them as "consumed" on a weighted-average cost basis. Other entities follow an intangible asset model for emission allowances. On the basis of discussions with the staffs of the FASB and the SEC, either accounting model for EAs is acceptable, although the intangible model is considered preferable. Forward contracts to acquire or sell allowances are treated as either derivative or nonderivative instruments, primarily dependent on whether the related product/market is deemed readily convertible to cash.

International

In December 2004, the IFRIC released IFRIC 3 in an attempt to address how participants account for cap-and-trade emission trading schemes. IFRIC 3 stated that allowances are intangible assets and should be measured at fair value when received from the government. The grant of allowances is recognized in income systematically over the compliance period.

At its June 2005 meeting, the IASB decided to withdraw IFRIC 3 so that it could address the underlying accounting more comprehensively than originally envisaged by the IFRIC. IFRIC 3 was criticized by some constituents because of its effect on the income statement. Although it was withdrawn, several IASB members indicated at the time that they believed IFRIC 3 properly interpreted existing IFRSs. At its September 2005 meeting, the IASB voted to add a project to its agenda to provide a comprehensive model for emission allowances that would address issues similar to those discussed in IFRIC 3.

Joint Convergence Project

In February 2007, the FASB decided to add a project to its agenda to provide comprehensive guidance for use by participants in emission trading programs, ultimately working jointly with the IASB. The FASB advised the staff to give the project a broad scope that would include all emissions trading schemes and tradable rights. Accordingly, this project is expected to cover both cap-and-trade and baseline-and-credit schemes (whether government mandated or voluntary) as well as project-based certificates and potentially renewable energy certificates. The guidance is expected to apply to participants in a scheme and nonparticipants that buy and sell tradable rights. The FASB also advised the staff that it need not limit itself to existing authoritative literature when developing possible accounting models.

Recognition

The boards discussed the initial accounting issues in a cap-and-trade scheme, specifically, whether purchased allowances and allowances allocated by the scheme administrator meet the definition of an asset and should be recognized as such in the statement of financial position. The boards also discussed whether an obligation meeting the definition of a liability exists when an entity is allocated the allowances.

The boards tentatively decided that purchased and allocated allowances should be recognized as assets. They also tentatively decided that the allocation of allowances creates an obligating event that meets the definition of a liability (although board members and staff had varying views on how to specifically characterize the nature of the obligation) and should be recognized as such in the statement of financial position.

In addition, the boards discussed how an entity should determine the quantity of allowances that would be returned under the liability for the allocation, as well as when an entity should recognize an obligation for emissions in excess of the liability for the allocation. Some board members supported recognizing the excess liability throughout the compliance period as an entity emits, while others supported recognizing the excess liability when the entity's emissions exceed the liability for the allocation. The boards asked the staff to seek feedback from stakeholders on both views.

Measurement

The boards tentatively decided that the measurement of the allocated allowances and the liability for the allocation should be consistent and that the allocated allowances and liability for the allocation should be initially and subsequently measured at fair value. The boards also tentatively decided that purchased allowances should be initially and subsequently measured at fair value.

Presentation

The IASB preferred gross presentation of the assets and liabilities on the balance sheet; however, it indicated that it would not object to a linked presentation. (In a linked presentation, the assets and liabilities would be presented gross, but the amounts would be presented together and total to a net emission asset or net emission liability.) The FASB tentatively decided that entities should present the assets and liabilities on the balance sheet by using a form of linked presentation. However, the FASB also indicated that it did not believe that an entity needed to have the intention of offsetting the assets and liabilities to be able to use a linked presentation.

Next Steps

The boards asked the staff to perform outreach activities on their tentative decisions to date and to present feedback in the second half of 2011. However, discussions on the emissions trading scheme project were deferred in November 2010 when the boards decided to amend the timetable and priority of certain projects. As a result, further action is not expected in the near term. The IASB will separately consider whether the project will remain on its agenda as part of its current agenda consultation process.

Industry Considerations

Although the project is currently deferred and there is no clear timeline regarding when it will be reactivated, the tentative decisions reached by the boards to date would result in an accounting model that is drastically different from the approaches commonly employed in the industry today. Namely, while broad consensus has maintained that allowances held represent assets of an entity, most industry participants do not believe that an emissions liability is incurred until the entity emits pollutants. Further, the measurement models used by most within the industry equate to some form of weighted-average cost for allowances (subject to lower-of-cost or market adjustment), including the impact of zero cost allocated allowances and associated cost of related emissions obligations.

Given the significance of the new CSAPR cap-and-trade program and the resulting increase in tradable environmental credits, the accounting differences resulting from the boards' tentative decisions above may be compounded. Companies are encouraged to continue closely monitoring the status of this project. Note that at the request of the FASB, the EEI authored a whitepaper that presents an industry view on existing practice and a proposed accounting model. The whitepaper also expresses support for the project's objectives and requests participation in further dialogue and field testing.

Rate-Regulated Activities

IASB Developments and Current Status

Rate (price) regulation is a fundamental aspect of the regulated energy industry. In the United States and much of North America, such regulation is designed to ensure that customers are charged reasonable rates for services and products while giving regulated entities an opportunity to recover prudently incurred costs of providing service plus a fair return on their capital investments. Under U.S. GAAP, ASC 980 provides guidance on the recognition of regulatory assets and liabilities that result from the actions of regulatory bodies that direct the rate-making process of the entity. Currently, no equivalent standard exists in IFRSs.

On July 23, 2009, the IASB issued an ED that would establish how assets and liabilities resulting from rate-regulated activities should be recognized and measured. The IASB added the project to its agenda after receiving ongoing requests for guidance and because of the importance of rate regulation in many jurisdictions that are in the process of adopting IFRSs. The ED's comment period ended November 20, 2009.

After consideration of comment letters received and the results of redeliberations, the IASB concluded that the matter could not be resolved quickly. The Board therefore decided to include in its public consultation on its future agenda a request for views on what form a future project might take, if any, to address rate-regulated activities. Potential future steps outlined by the IASB include, but are not limited to:

- A disclosure only standard.
- An interim standard to grandfather previous GAAP accounting practices with some limited improvements.
- A medium term project focused on the effects of rate-regulation.
- A comprehensive project on intangible assets.

Note that on July 26, 2011, the IASB issued Agenda Consultation 2011 to gather public views on the strategic direction of its work plan and on the priority of individual projects and areas of financial reporting over the next three years. Appendix C of the agenda consultation includes rate-regulated activities in the list of "projects previously added to the agenda but deferred and new project suggestions." Comments on the agenda consultation were due November 30, 2011.

Canadian Activities

Public entities in Canada are required to adopt IFRSs for the first time for annual periods beginning on or after January 1, 2011. The AcSB provided for a one-year deferral of IFRS adoption for entities that have activities subject to cost-based regulation and that currently recognize regulatory assets and liabilities under Canadian GAAP (under requirements similar to the ASC 980 model). In May 2011, the CSA considered granting exemptive relief applications that would allow entities with rate-regulated activities that are not SEC issuers to file U.S. GAAP financial statements until years commencing on or after January 1, 2015. Shortly thereafter, some provincial securities regulators in Canada began accepting these applications and granting the requested relief, effectively delaying adoption of IFRSs for Canadian utilities with "activities subject to rate regulation" for an additional three years past the one-year deferral granted by the AcSB.

Canadian regulated energy companies have generally been pursuing one of two approaches, with most having already taken advantage of the one-year deferral granted by the AcSB, which expired January 1, 2012:

- Adopting U.S. GAAP as an alternative allowed by Canadian securities regulators.
- Proceeding with 2011 IFRS adoption and analyzing regulatory assets and liabilities within the IFRS framework.

Canadian regulated entities that have opted to list their securities in the United States and adopt U.S. GAAP will be subject to the cost and effort of compliance with Section 404 of the Sarbanes-Oxley Act.

U.S. Industry Efforts to Date

Working individually and through industry trade associations such as the EEI and the AGA, regulated U.S. energy companies remain active in discussing the merits of retention of an accounting standard for rate-regulated activities. EEI and AGA member companies have held numerous discussions and educational sessions with the IASB, FASB, and SEC since publication of the IASB's ED to ensure that the nature of U.S. rate regulation and resulting economic effects are well understood.

The EEI and AGA also commented on the SEC's May 26, 2011, staff paper that presents a possible framework for incorporating IFRSs into the U.S. financial reporting system (see Section 3 of this publication for more information). The industry generally supported adoption of an approach that allows for retention of local or industry-specific accounting guidance (in the absence of international standards) when appropriate to reflect the economic realities of the local environment; protect investors; maintain fair, orderly, and efficient capital markets; and facilitate capital formation in the United States. The EEI's response also included a whitepaper further detailing the nature of cost-based regulation within the U.S., applicability of ASC 980 to the U.S. regulatory environment, consistency of ASC 980 with the U.S. conceptual accounting framework, and consistency of the U.S. conceptual framework with the international accounting framework. Finally, the FERC also participated in the SEC's July 2011 regulatory roundtable to discuss the staff paper and the impact of IFRS adoption on the industry, highlighting the need for an accounting model under IFRSs that is equivalent to ASC 980.

Next Steps

Regulated energy companies should continue to monitor the SEC's developments as it progresses in its work plan on the consideration of incorporating IFRSs into the U.S. financial reporting system. Further, note that both the EEI and AGA responded to the IASB's request for comment on its next three-year project agenda to encourage a joint approach between the FASB and IASB in developing an international accounting standard on rate-regulated activities.

Section 8
FERC Update

Introduction

In previous editions of the Energy & Resources Update, we described the increasing importance of regulatory compliance in the E&R industry and the P&U sector in particular.

In 2011, the FERC continued efforts to clarify its regulation and enforcement activities, and in November the FERC's Office of Enforcement ("FERC Enforcement") issued its *2011 Report on Enforcement*.

According to the report, the FERC seeks to balance (1) its obligation to keep nonpublic investigation matters confidential and (2) its new effort to inform the public of the activities of the staff of FERC Enforcement. The 2011 report provides information about priorities and activities, and many subject to FERC jurisdiction felt that it successfully increased transparency about FERC Enforcement.

The report notes that FERC Enforcement upheld the previously established priorities of FY2010 and FY2011 for FY2012:

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

FERC Enforcement selected the 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.

In April 2011, the FERC issued a $30 million fine on a former Amaranth trader. This civil penalty was, according to the FERC, the first fully litigated proceeding involving its enhanced enforcement authority under Section 4A of the National Gas Act.

In the last year of reported data (FY2011), the FERC approved nine settlement agreements as compared with six in FY2010 and 22 in FY2009. The number of open access violation settlements and reliability standards violations remained unchanged at three and two, respectively. These settlements resulted in payments totaling roughly $3 million in civil penalties and disgorgement of over $2.7 million plus interest. Enforcement also processed 270 Notices of Penalty filed by the NERC, in which regional entities proposed $12 million in penalties. In FY2010, FERC settlements totaled $31.4 million in total civil penalties, including one for $25 million, and disgorgement of less than $0.3 million plus interest.

The 107 self-reports filed in FY2011 represented a 93 percent increase from the previous year. There were 37 self-reports of Tariff/OATT violations in FY2011, up from 32 in FY2010. In both years, this was the most common type of violation self-reported. Failure to file was the second most common self-reported violation, with 22 cases in FY2011 compared with 7 cases in FY2010. The third most common self-reported violation was the open access violation, with 20 cases in FY2011 and 13 cases in FY2010.

FERC Enforcement has three divisions: Investigations, Audit, and Market Oversight. Each is discussed below.

Investigations

The FERC investigations staff opened 12 investigations in FY2011, down from 15 in FY2010. Five investigations involved more than one type of violation:

- Five addressed RTO/ISO tariff violations.
- Eight involved market manipulation.

- Two related to Commission-issued hydropower licenses.
- One involved Standards of Conduct.
- One involved the FERC's authority under the Interstate Commerce Act.

The FERC and NERC staffs have improved their cooperation in investigations of recent blackouts. The FERC investigations staff is currently conducting a joint inquiry with the NERC into potential violations of reliability standards connected to the September 8, 2011, power outages in parts of Southern California, Arizona, and northern Baja California, Mexico. A separate joint inquiry between the FERC and NERC staffs, launched in February 2011 in response to widespread electricity outages and gas curtailments in Texas, New Mexico, and Arizona, concluded in August 2011. The concluding report outlined 26 recommendations to operators.

Audits

In FY2011, the Division of Audits (DA) within FERC Enforcement completed 72 audit activities:

- Fifty-six audits of public utilities, natural gas pipelines, and storage companies (financial and nonfinancial).
- Sixteen 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 DA staff's oversight of audits performed by regional entities influenced FERC guidance to the NERC on the appropriate application of audit techniques and the interpretation of standards.

In FY2010, the FERC undertook its first multi-objective probe of a pipeline's compliance with selected reporting and accounting requirements in Order No. 581. The staff identified a dozen "noncompliance" findings and reporting errors in the Index of Customers (in compliance with NAESB standards) and filed a nonconforming contract with a total of 23 audit staff recommendations. All audit staff recommendations were approved by the FERC. In FY2011, the FERC continued such multi-objective probes in the gas pipeline sector, evaluating two pipeline operators for compliance with NAESB standards, nonconforming contract requirements, FERC Form No. 2 Filing requirements, and select reporting and accounting requirements in Order No. 581. The FERC staff compiled seven findings for one pipeline operator and ten findings for the other, primarily related to accounting and reporting errors.

In November 2011, the FERC DA staff began discussions with the SEC staff to potentially incorporate IFRSs into the financial reporting system of publicly traded U.S. companies. IFRSs would replace the current set of accounting regulations based on U.S. GAAP. In July 2011, the FERC DA chief accountant endorsed a proposal for a gradual incorporation of IFRSs into U.S. GAAP over a defined timeframe rather than all at once. The SEC, which has the ultimate authority over financial reporting standards, has not yet adopted a plan to incorporate IFRSs.

In February 2011, the FERC adopted a new policy on Accounting Release No. 5, *Capitalization of Allowance for Funds Used During Construction* (AFUDC). The old policy barred natural gas pipelines from AFUDC capitalization until after the filing of an application by the pipeline to the FERC for a certificate of public convenience and necessity. The new policy allows pipeline companies to capitalize AFUDC once they have "incurred capital expenses for the project and activities necessary to get the project ready are progressing."

Market Oversight

The Division of Market Oversight administers and ensures compliance with the FERC's filing requirements, reviewing submissions for:

- Nine annual report series.
- Seven quarterly report series.

It also observes and reports on energy markets relevant to FERC jurisdictional responsibilities to identify anomalies that may require FERC attention.

In FY2010, the FERC revoked the market-based rate authorization of six sellers "for failure to timely file their EQRs." In FY2011, the FERC did not revoke any market-based rate authorizations.

Other Developments

Though the FERC has undertaken many other projects in 2011, it has not completed some of them. For instance, 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 there is no new Dodd-Frank MoU in place at this time. The lack of a new agreement creates regulatory uncertainty regarding the organized markets of RTOs and ISOs. FTRs and CRRs (congestion hedging devices for electric power transactions) could be subject to regulations by both agencies. The RTOs and ISOs appear open to cooperation with the CFTC at this time.

Also in 2011, the 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 it appears unlikely to move forward.

In pipeline safety matters, the fatal San Bruno accident in September 2010 has led to greater scrutiny of the area. The Pipeline and Hazardous Materials Safety Administration in the Department of Transportation, and not the FERC, has regulatory responsibility for pipeline safety. The National Transportation Safety Board found, among other problems, inadequate record keeping and physical testing, especially for old pipeline segments. FERC decisions about rate treatment for new safety measures could affect pipeline profitability and reactions to new requirements.

During 2011, the FERC also deliberated on demand-side resources, incentives for additional electric transmission (on and off shore), capacity market issues, regulatory treatment of electricity storage, and other means of providing ancillary services. The FERC explored ideas about these topics, but did not finalize policies.

Regulatory uncertainty has increased for some aspects of the FERC's jurisdiction, but the need for improved document management, records retention, and compliance governance remains clear. Industry leaders are working to enhance compliance programs and to adopt strategies that can provide optionality for the regulatory changes likely to happen in the foreseeable future.

Section 9
Income Tax Update

Introduction

This section summarizes FASB, FERC, and IRS pronouncements related to accounting for income taxes as well as federal and state income tax developments affecting the financial and regulatory reporting of income taxes. The discussion of IFRSs in Section 3 describes the impact on accounting for income taxes in relation to the conversion from U.S. GAAP to IFRSs. The accounting for treasury grants, ITCs, and PTCs is discussed in Section 10.

Health Care Legislation Eliminates Tax Deduction Related to Medicare Part D Subsidy

The revenue-raising provisions of the comprehensive health care legislation enacted in March 2010 included a tax law change 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 pre-subsidy amount of the obligation, and a deferred tax liability was not required for the subsidy receivable.

As a result of the tax law change, the tax deduction is eliminated 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 will not be eliminated until 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, scheduling the estimated amount of retiree prescription drug costs to be funded by the Medicare subsidy before 2013 is necessary for an entity to calculate the deferred tax adjustment recorded in the period of enactment. This estimate should be revisited periodically before the prospective effective date of the tax law change. 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, including in situations in which 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 — Deferred Investment Tax Credit (Formula Rates)

During 2010, the IRS issued a pair of nearly identical PLRs (201022007 and 201022008) related to the amortization of ADITC under Option 2. Under Option 2, ADITC may not reduce rate base, but the related amortization may reduce the tax provision no more rapidly than ratably over the regulatory lives of the assets. Ratably is defined as the period used in the computation of the taxpayer's regulated depreciation expense. Regulations provide that this depreciation expense must be determined on the basis of the period the assets are used by the taxpayer, without reduction for salvage value or other items. Note that Option 1 taxpayers may not reduce regulatory tax expense for ITC amortization but may reduce rate base by ADITC as long as the rate base reduction is restored no less rapidly than ratably over the regulatory lives of the assets.

The PLRs were issued in response to electric transmission providers that set prices by using a formula-rates approach and had made a proper election to amortize deferred ITC under Option 2. The taxpayers began using a rate template that had been used by other transmission providers. The template was developed so that transmission providers could use it whether they had elected Option 1 or Option 2. In one instance, the taxpayer's regulatory personnel were not familiar with the normalization requirements and did not realize that the two fields in the template were alternatives. The taxpayer inadvertently populated both fields, reducing the rate base and cost of service. Rates were ultimately approved without detection of the template population error by the customers involved in rate negotiations or the commission. At a later date, while considering ITC associated with a potential investment in solar generating assets, the taxpayer noticed its error in the prior rate filings. The taxpayer corrected its submission, and rates were increased shortly thereafter.

In the PLRs, the IRS exercised its discretion not to disallow or recapture ITC because the errors were inadvertent and the commissions neither specifically addressed these matters in the rate cases nor insisted on the erroneous rate treatment. The IRS indicated that its analysis would not apply to rate orders finalized after the dates of the rulings.

Normalization — Deferred Investment Tax Credit (Depreciation Studies)

The IRS issued 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.

Section 10
Renewable Energy

American Recovery and Reinvestment Act of 2009

Introduction

In an effort to create jobs and promote economic growth during the credit crisis, President Obama signed into law the American Recovery and Reinvestment Act of 2009 (the ARRA or the "Act") in February 2009. The ARRA outlines new federal income tax credits, government grants, and other economic incentives.

Section 1603 of the ARRA contains a number of provisions that extend or modify existing renewable energy tax incentives. The ARRA 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., 2011 wind production at 2.2 cents) multiplied by kWh generated during each of the first 10 years of operation.

The energy credit under IRC Section 48 is an ITC available for certain renewable energy facilities placed in service through specified dates (e.g., before December 31, 2012, for wind; December 31, 2013, for other PTC-eligible property; and December 31, 2016, for solar). 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 ARRA provides for an irrevocable election under IRC Section 48(a)(5) to claim ITC instead of 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 ITC in lieu of 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 ITC in lieu of PTC, and the historical ITC normalization requirements for regulated entities apply to such property.

Section 1603 of the Act allows the Treasury secretary to provide a grant in lieu of ITC (a "Section 1603 grant") for renewable generation property, including public utility property. In December 2010, the Tax Relief, Unemployment Insurance Reauthorization and Job Creation Act of 2010 (the "2010 Act") extended Section 1603 of the Act for one year to continue to allow the Treasury secretary to provide a Section 1603 grant provided construction commenced by December 31, 2011, and is placed in service before the ITC placed-in-service requirement that otherwise applies to such property (e.g., by December 31, 2012, for wind generation facilities or December 31, 2016, for solar generation facilities). If construction commenced after December 31, 2011, the property will not be eligible for Section 1603 grants but will still be eligible for ITC if placed in service before the applicable ITC expiration date. A key difference between ITC 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 ITC on the basis of tax liability or tentative minimum tax. Section 1603 grants are similar to ITC 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 (i.e., more restrictive than the ITC rules).

In general, initial Section 1603 grant applications must be submitted before October 1, 2012 (also extended for one year under the 2010 Act), even though the property may be placed in service later. Both initial and final applications for qualified properties with an eligible cost basis of $500,000 or more must be accompanied by some form of an independent accountant's certification. Section 1603 grants are to be paid to applicants within 60 days of the later of the placed-in-service date of the plant or the submission of the application. In July 2009, the Treasury published guidance, "Payments for Specified Energy Property in Lieu of Tax Credits Under the American Recovery and Reinvestment Act of 2009" (the "program guidance") on Section 1603, and it made online application forms available in August 2009.

Updated Program Guidance and Frequently Asked Questions

The Treasury issued updated program guidance and FAQs in March and June 2010, respectively, to clarify certain provisions of the program guidance. The program guidance and FAQs were further updated in April 2011 for the one-year extension under the 2010 Act. The FAQs are aimed at clarifying eligibility requirements for properties placed in service after December 31, 2011, as a result of meeting the beginning-of-construction criterion (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 be 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.” Treasury acknowledges that physical work of a significant nature can consist of either on-site construction or the execution of a binding contract for the production of equipment with a third-party contractor as long as the contract terms do not “limit damages in the event of a breach to less than 5% of the total contract price.” An entity would consider only costs directly associated with the power-producing assets when evaluating whether an applicant has met the physical work of a significant nature requirement. Costs associated with certain transmission assets or support, such as maintenance facilities, roadways, fencing, and site preparation (e.g., clearing and leveling) do not qualify under the physical work of a significant nature criterion. Also, applicants relying on the binding contract provision to satisfy the physical work of a significant nature requirement must demonstrate that the binding contract is enforceable **and** that the assets under contract are distinguishable from other assets in production, or held in inventory, by the counterparty before December 31, 2011.

- A cost may satisfy the economic performance requirements of IRC Section 461(h) (see Treas. Regs Section 1.461-1(a)(1) and (2)). However, if construction is not substantially continuous, then the performance of the terms in the binding contracts is not ongoing in nature from December 31, 2011, through the placed-in-service date, and the project may be considered ineligible. 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) will be considered in determining 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 the application for the 5 percent safe harbor is made, 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 having incurred insufficient costs to meet the safe harbor before 2011. If cost overruns void an applicant’s safe harbor, 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. Bifurcation must be based on 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 3½ months from the date of payment (supplier's payment to subcontractor) is considered to be provided by the payment date.

- Applicants seeking eligibility to receive Section 1603 grants under the "physical work of a significant nature" or the 5 percent safe harbor provision of the ARRA for properties with placed-in-service dates after December 31, 2011, must file an initial application with Treasury before October 1, 2012, to demonstrate that "physical work of a significant nature" has commenced, or that costs paid or incurred before December 31, 2011, constitute at least 5 percent of the total estimated eligible project costs. Applicants seeking eligibility under the 5 percent safe harbor provision for projects with an estimated eligible cost basis of $1 million or more must also include a certification from an independent accountant. The Treasury will accept either an Agreed-Upon Procedures report prepared by an independent accountant in accordance with AT Section 201, "Agreed-Upon Procedure Engagements," of the AICPA, 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 AT Section 101, "Attest Engagements" (Statements on Standards for Attestation Engagements 10, as amended) of the AICPA.

The program guidance and FAQs and instructions to the Agreed-Upon Procedures are available on the Treasury Department's Web site.

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 credit carry forwards to determine whether a valuation allowance is necessary.

Accounting for Grant-Eligible ITC and Section 1603 Grants

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

There is a view that Section 1603 grants would be elected in lieu of ITC when such election is available because generally it would be economically advantageous to make such election. However, in certain circumstances there may be economic disadvantages in electing the Section 1603 grants in lieu of ITC. For example, Section 1603 grants could be subject to state income taxation in some states under existing state tax law or amendments enacted in response to the ARRA, whereas ITC and other federal tax credits would not be taxable. If ITC is claimed 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 ITC, the initial ITC accounting should be converted to grant accounting when the ITC is recaptured and converted to a Section 1603 grant.

When ITC eligible for Section 1603 grants and the Section 1603 grants are accounted for as grants, the related balances should be 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 (note that there is no specific U.S. GAAP guidance on accounting for government grants). The benefit should be recognized over the book life of the property and should not be recorded as a reduction of income tax expense, but it would generally be recorded as a reduction to depreciation and amortization.

Day 1 Deferred Tax Entries

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

- *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 should not result in immediate income statement recognition." In addition, as illustrated in ASC 740-10-55-171 through 55-182, the simultaneous-equations method should be used to calculate the reduction to the book basis and the related deferred tax asset. This method is considered preferable in the current circumstances.

- *Method 2* — Recognize the offset to the deferred tax asset as a reduction of income tax expense. This method would be based on a conclusion that the simultaneous-equations method does not apply to grant-eligible ITC 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 also 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 this method is chosen, entities should consider recognition of the impact of the income tax expense reduction in their estimated annual effective tax rates for interim financial statements, in accordance with ASC 270-10 and ASC 740-270. 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. For rate-regulated entities, both the ITC and Section 1603 grant were subject to the ITC normalization requirements under the ARRA as enacted. However, the National Defense Authorization Act for Fiscal Year 2012, enacted on December 31, 2011, amended Section 1603 of the ARRA to retroactively repeal the normalization requirement for Section 1603 grants. Regulated entities are still required to normalize ITC claimed on renewable energy facilities. Depending on the normalization election made, the regulated entities must assure that the unamortized ITC is not used to reduce rate base (Method 2 entities) or that the reduced book depreciation from the grant is not reflected as a reduction in cost of service (Method 1 entities). Further, restoration of the rate base reduction for Option 1 entities and amortization through cost of service for Option 2 entities must be in accordance with the applicable normalization rules. The application of the normalization requirements to ITC but not to Section 1603 may affect the economic analysis for rate-regulated entities determining whether ITC claimed on renewable energy facilities must be accounted for under the grant accounting rules.

Grant Eligible ITC Claimed on QPEs

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

Structuring Project Arrangements and the Resulting Accounting and Tax Implications

The use of renewable energy tax benefits 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 wind generation, 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 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.

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. In the early years of a wind project, renewable energy businesses often do not generate sufficient taxable income to take advantage of the tax benefits. Consequently, the business would have to carry over unused tax credits and evaluate whether the credits comply with ASC 740-10-30-2.

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

Investors in structures are typically entities with available cash and high tax liabilities. Before the recent credit crisis, these investors were typically investment banks, 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 pay a large sum of 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 and Types of Traditional Structures

Structures contain certain features that allow them 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 wind project. Under this arrangement, the investor purchases an interest for cash and is allocated a majority of the tax benefits (e.g., PTCs, MACRS 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 the investor's partnership interest. Under IRS approved rules, 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 renewable tax benefits to offset its tax liability.

Structures typically contain the following features[20] to ensure favorable tax treatment:

- 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 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.

One variable of structures is the timing of the cash receipts from an investor. In some arrangements, the investor makes a large, up-front cash payment upon formation of the partnership. The amount of cash is meant to capture the expected tax benefits the investor will receive throughout the life of the structure. Current economic conditions, and the emphasis placed on liquidity, have prompted investors to look for other ways to consummate structures without making such large, up-front cash payments.

Accounting and Reporting Considerations for Traditional Structures

As noted above, renewable energy businesses often establish a partnership and sell a portion of the interest to the investor. Entities should consider various approaches in accounting for the sale of partnership interest.

One method is to follow ASC 360-20 and account for the arrangement as a sale of real estate. 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.

[20] As summarized from the safe harbor guidance in IRS Revenue Procedure 2007-65. Although they are explicitly applicable to wind partnerships with production tax credits, the features are also often copied in structures for other credits, such as, solar and biomass.

If the entity concludes that the sale of the partnership interest is within the scope of ASC 360-20, it must then determine how to account for the sale. 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 arrangement's structure prevents profit recognition by the full accrual method, renewable energy businesses must account for the sale of the partnership interest under another method described in ASC 360-20-40-28 through 40-64. In selecting such method (e.g., deposit, financing, leasing, profit-sharing), the businesses must consider the specific facts and circumstances. However, when applying the methods to account for the sale of partnership interests, renewable energy businesses should consider the effects on the balance sheet, the income statement, and the cash flow statement to ensure that the accounting and disclosures are appropriate and consistent.

Another method might be to account for the arrangement as a sale of noncontrolling interests under ASC 810-10. ASC 810-10-20 defines a noncontrolling interest as the "portion of equity (net assets) in a subsidiary not attributable, directly or indirectly, to a parent." Accordingly, the sale of a partnership interest may be considered to be within the scope of ASC 810-10 because the renewable energy business essentially sells part of its equity interest in the wind partnership project to the investor. ASC 810-10-45-15 through 45-24 discuss noncontrolling interests and provide guidance on how to account for the sale of a noncontrolling interest. If an entity accounts for the sale of a partnership interest under ASC 810-10, it should consider the effects on the balance sheet, income statement, and cash flow statement to ensure that the accounting and disclosures are appropriate and consistent.

The accounting and reporting considerations discussed above are from the perspective of renewable energy businesses. However, both renewable energy businesses and investors need to evaluate structures under ASC 810 to determine which party is required to consolidate them.

Last but not least, 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.

Tax Considerations

The beneficial tax treatment for structures is governed by IRS Revenue Procedure ("Rev. Proc.") 2007-65. In October 2007, the IRS provided a safe harbor for partnership arrangements that identifies the economic terms that must be present in structures. 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 tax benefits.

The safe harbor provisions are outlined above in Features and Types of Traditional Structures and must be met to ensure that the IRS will not challenge the arrangements. Rev. Proc. 2007-65 only applies to partnerships in wind projects.

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. Certain investors are subject to regulatory requirements to demonstrate an ability to exit certain types of investment (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 equity or liability-like. The guidance in ASC 480 might prove 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 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 IFRSs

One difference between U.S. GAAP and IFRSs 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 IFRSs. 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 cash to be distributed to the members of the partnership. In other words, 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. However, because none of the members of the partnership has the ability or the option to determine whether, and if so, when cash should be distributed (i.e., cash distributions are required once cash is available), a similar feature in a traditional structure is likely to result in a liability classification of the investor's partnership interest under IAS 32.

U.S. GAAP and IFRSs also differ in their treatment of tax credits in traditional structures, such as PTCs. ASC 740-10 governs the accounting of tax credits under U.S. GAAP, while IAS 12 excludes the accounting of tax credits. As a result, most entities have accounted for tax credits on the basis of their nature and substance under IFRSs.

While there are significant differences in the accounting for traditional structures under U.S. GAAP and IFRSs, entities should consider all relevant facts and circumstances in determining the appropriate accounting under each framework.

Appendixes

Appendix A — Abbreviations

Abbreviation	Description
ABS	asset-backed security
ACI	activated carbon injection
AcSB	Canadian Accounting Standards Board
ADITC	accumulated deferred investment tax credits
AFUDC	allowance for funds used during construction
AGA	American Gas Association
AICPA	American Institute of Certified Public Accountants
ARO	asset retirement obligation
ARRA	American Recovery and Reinvestment Act of 2009
ASC	FASB Accounting Standards Codification
ASU	FASB Accounting Standards Update
bcfd	billion cubic feet per day
CAIR	Clean Air Interstate Rule
CAQ	Center for Audit Quality (affiliated with the AICPA)
C&DIs	SEC Compliance and Disclosure Interpretations
CD&A	compensation discussion and analysis
CFDG	SEC's Corporation Finance Disclosure Guidance
CFTC	Commodity Futures Trading Commission
COD	cash on delivery
CRR	congestion revenue rights
CSA	Canadian Securities Administrators
CSAPR	Cross-State Air Pollution Rule
DA	FERC's Division of Audits
DOE	U.S. Department of Energy
DOJ	U.S. Department of Justice
ED	exposure draft
EDGAR	SEC's Electronic Data Gathering, Analysis, and Retrieval System
EEI	Edison Electric Institute
EITF	Emerging Issues Task Force
E&R	energy and resources
EPA	Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas
ESP	electrostatic precipitators
FA&RS	Deloitte's Financial Accounting & Reporting Services
FAQs	frequently asked questions
FASB	Financial Accounting Standards Board

Abbreviation	Description
FERC	Federal Energy Regulatory Commission
FF	fabric filter
FIFO	first-in first-out
FRM	SEC's Division of Corporation Finance Financial Reporting Manual
FTR	financial transmission rights
FV-NI	fair value through net income
FV-OCI	fair value through other comprehensive income
GAAP	generally accepted accounting principles
IAEA	International Atomic Energy Agency
IAS	International Accounting Standards
IASB	International Accounting Standards Board
IBR	incremental borrowing rate
ICFR	internal control over financial reporting
IFRIC	International Financial Reporting Interpretations Committee
IFRS	International Financial Reporting Standard
IPE	investment property entity
IPO	initial public offering
IRC	Internal Revenue Code
IRS	Internal Revenue Service
ISO	Independent System Operator
ITC	investment tax credit
kWh	kilowatt hour
LIFO	last-in first-out
LLC	limited liability company
MACRS	modified accelerated cost recovery system
MACT	maximum achievable control technology
MATS	Mercury and Air Toxics Standards
MD&A	Management's Discussion and Analysis
MoU	Memorandum of Understanding
MWh	milliwatt hour
NAESB	North American Energy Standards Board
NERC	North American Electric Reliability Corporation
NDT	nuclear decommissioning trust fund
NOX	nitrous oxide
NPNS	normal purchase normal sale
NRC	Nuclear Regulatory Commission
NWPA	Nuclear Waste Policy Act of 1982
NYMEX	New York Mercantile Exchange

Abbreviation	Description
OATT	Open Access Transmission Tariff
OCI	other comprehensive income
OPEB	other postemployment benefits
OTC	over the counter
OTTI	other than temporary impairment
P&L	profit and loss
P&U	power and utilities
PCAOB	Public Company Accounting Oversight Board
PGA	purchased gas adjustment
PJM	Pennsylvania, Jersey, Maryland Power Tool
PLR	IRS private letter ruling
PPA	power purchase agreement
PP&E	property, plant, and equipment
PRB	Powder River Basin
PTC	production tax credit
REC	renewable energy certificate
Rev. Proc.	IRS Revenue Procedure
RRA	rate-regulated activities
RTO	Regional Transmission Organization
SAB	SEC Staff Accounting Bulletin
SCR	selective catalytic reduction
SEC	Securities and Exchange Commission
SIC	Standing Interpretations Committee
SO_2	sulfur dioxide
SOX	sulfur oxide
TA&I Committee	FASB's Technical Application and Implementation Activities Committee
TCF	trillion cubic feet
VIE	variable interest entity
WKSI	well-known seasoned issuer
XBRL	eXtensible Business Reporting Language

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

IASB Exposure Draft, *Rate-regulated Activities*

SEC Literature

- Exemptive Order No. 34-64678, *Temporary Exemptions and Other Temporary Relief, Together with Information on Compliance Dates for New Provisions of the Securities Exchange Act of 1934 Applicable to Security-Based Swaps*
- Final Rules, Interim Final Rules, Proposed Rules, and Interpretive Releases:
    - Final Rule No. 33-9136, *Facilitating Shareholder Director Nominations*
    - Final Rule Nos. 33-9142 and 34-62914, *Internal Control Over Financial Reporting in Exchange Act Periodic Reports of Non-Accelerated Filers*
    - 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*
- Final Rule No. 33-9286, *Mine Safety Disclosure*
- Final Rule No. 34-64545, *Implementation of the Whistleblower Provisions of Section 21F of the Securities Exchange Act of 1934*
- 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. 33-8982, *Roadmap for the Potential Use of Financial Statements Prepared in Accordance With International Financial Reporting Standards by U.S. Issuers*
- 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. 34-63547, *Conflict Minerals*
- 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. 34-64352, *Removal of Certain References to Credit Ratings Under the Securities Exchange Act of 1934*
- 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:

- Form 8-K, "Current Reports": Item 4.01, "Changes in Registrant's Certifying Accountant"
- Form 10-K, "General Form of Annual Report"

• FRM:

- Topic 1, "Registrant's Financial Statements"
- Topic 2, "Other Financial Statements Required"

- Topic 4, “Independent Accountants’ Involvement”
- Topic 6, “Foreign Private Issuers & Foreign Businesses”

- Regulation C, “Registration”:
  - Rule 430B, “Prospectus in a Registration Statement After Effective Date”
  - Rule 433, “Conditions to Permissible Post-Filing Free Writing Prospectuses”
- Regulation FD, “Fair Disclosure”
- Regulation S-K:
  - Item 304, “Changes in and Disagreements With Accountants on Accounting and Financial Disclosure”
  - Item 401, “Directors, Executive Officers, Promoters and Control Persons”
  - Item 402, “Executive Compensation”
    - Item 402(b), “Executive Compensation: Compensation Discussion and Analysis”
    - Item 402(t), “Executive Compensation: Golden Parachute Compensation”
  - Item 601, “Exhibits”
- Regulation S-T:
  - Rule 405, “Interactive Data File Submissions and Postings”
  - Item 406T, “Temporary Rule Related to Interactive Data Files”
- Regulation S-X:
  - Rule 3-09, “Separate Financial Statements of Subsidiaries Not Consolidated and 50 Percent or Less Owned Persons”
  - Rule 3-10, “Financial Statements of Guarantors and Issuers of Guaranteed Securities Registered or Being Registered”
  - Rule 3-16, “Financial Statements of Affiliates Whose Securities Collateralize an Issue Registered or Being Registered”
- SAB Topic 10.E, “Classification of Charges for Abandonments and Disallowances”
- Staff Paper: *Work Plan for the Consideration of Incorporating International Financial Reporting Standards Into the Financial Reporting System for U.S. Issuers — Exploring a Possible Method of Incorporation* (May 26, 2011)

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Acknowledgments

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

Mickey Appel
Theresa Asarito
James Barker
Jodi Beining
Will Bible
Mark Bolton
Derek Bradfield
Lynne Campbell
Jeff Carr
Scott Cerutti
Kirk Crews
Mark Crowley
Bo Davis
Zach Deakins
Natalie Dickter
Joe DiLeo
Geri Driscoll
George Fackler
Jason Gambone
Bill Graf
Bill Hederman
David Horn
Brad Humpal
Marc Hunter
Elisabeth Indriani
Paul Josenhans
Tom Keefe
Tom Kilkenny
Steve Koesters
Tim Kolber
Patrick Larson
Eric Lukas
Derek Malmberg
Kristin Mascis
Stephen McKinney
Wendy Meredith
Michael Mueller
Brian Murrell
Adam Nicholson
Jason Nye
Katherine Ostrowski
Jeanine Pagliaro
Matt Parker
Ken Pressler
Nichole Quinn
Meredith Richard
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Tim Wilhelmy
Dave Yankee
Beth Young
Jan Umbaugh
Amy Zimmerman

Appendix D — Other Resources and Upcoming Events

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Events

March 27, 2012

Utility Industry Book/Tax Differences Training — Houston, TX

For more information or to schedule this seminar at your company, please contact USEnergyTaxSeminars@deloitte.com.

March 28, 2012

Accounting for Income Taxes: Rate-Regulated Utilities — Houston, TX

For more information or to schedule this seminar at your company, please contact USEnergyTaxSeminars@deloitte.com.

May 21–22, 2012

Deloitte Energy Conference — Washington, DC

For more information on the 2012 conference or to obtain a synopsis of the 2011 Deloitte Energy Conference, please contact: EnergyConference@deloitte.com.

Other Seminars

Alternative Energy Seminar — Fall, 2012 (Location TBD)

For more information please contact: AlternativeEnergy@deloitte.com.

Deloitte Energy Accounting, Financial Reporting and Tax Update — November 28, 2012 (Chicago, IL)

For more information please contact: USEnergyFallSeminars@deloitte.com.

Deloitte Energy Transacting Accounting — November 29, 2012 (Chicago, IL)

For more information please contact: USEnergyFallSeminars@deloitte.com.