Energy & Resources 2010 Accounting, Financial Reporting, and Tax Update

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Foreword

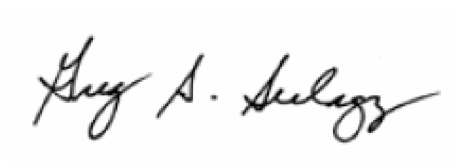
November 2010

As our industry continues to evolve as a result of changing markets, new legislation, and emerging businesses and technologies, finance practitioners are confronted with new challenges associated with the related tax, accounting, and reporting implications. In an effort to assist you with top of mind matters you may face in the coming year, we are pleased to present Deloitte's ninth annual *Accounting, Financial Reporting, and Tax Update*. The publication discusses accounting, tax, and regulatory matters, including SEC, FASB, IFRS, and tax updates for 2010, and focuses on specialized industry accounting matters frequently seen by rate-regulated entities. New to our annual update is a section on accounting and reporting matters specific to renewable energy.

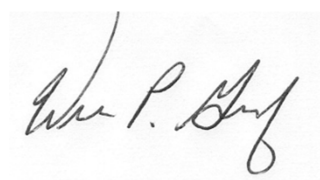
To address potential challenges in accounting and reporting of revenue, leases, and a host of other topics as a result of FASB exposure drafts issued this year, we have included a section about the Board's proposals and have highlighted nuances that could directly affect our industry.

This year's update covers developments that took place through the beginning of the fourth quarter. 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, and watch for our *Heads Up* newsletter, to be issued in mid-December, covering highlights from the 2010 AICPA National Conference on Current SEC and PCAOB Developments.

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



Greg S. Seelagy
Managing Partner, Energy & Resources
Deloitte & Touche LLP



William P. Graf
Power & Utilities Professional Practice Director
Deloitte & Touche LLP

Section 1
Industry Developments

The power and utilities (P&U) sector continued to navigate its way through actual and potential changes during 2010. Outlined below are changes not addressed in the rest of the publication.

Regulatory Compliance

Regulatory compliance has continued to gain prominence in the industry as a top area of focus for many energy companies. Ongoing enforcement actions by FERC and NERC, the recent passage of the Dodd-Frank Wall Street Reform and Consumer Protection Act, and the expectations that regulatory audits of market and operating practices will continue rising in the future have raised the bar for energy companies to look closely at the adequacy of their compliance efforts. The compliance risk issues that have continued to be top of mind for management are (1) concerns about the operational practices of business units charged with maintaining the reliability of the bulk power system, (2) the adequacy of documentation to help represent the adequacy of compliance practices within the company, and (3) the capabilities of owned or acquirable IT systems to sustainably support the compliance program. It is no longer sufficient for companies to treat compliance as a "check the box" exercise. Companies are now expected to prove it. Management teams' heightened awareness is due in large part to the financial and reputational impact that comes from nonperformance or weaknesses on the compliance front. In many ways, the regulatory expectations have motivated companies to reconsider their cultures of compliance by looking closely at their governance structures, the approaches to compliance risk management, their performance incentive structures, corporate and individual-level goals, senior management messaging about the commitment to compliance, the metrics that are used to gauge compliance performance, the adequacy of compliance training, and the quality of policy and procedure documentation.

The size of the auditing staffs at FERC, NERC, and the U.S. Commodities Futures Trading Commission has increased dramatically over the past two years to accommodate the greater level of auditing activity that is expected by the leadership at all of these regulatory bodies. This increased auditing activity is being promoted in an effort to further stimulate the industry to strengthen its compliance programs, not necessarily to impose more enforcement actions. With this increased auditing activity, however, has come a heightened awareness of what companies are doing well and where they are struggling in connection with compliance. Regulatory auditors are also getting sharper in their understanding of the substance of compliance practices and in their ability to more readily identify gaps and deficiencies in programs. Accordingly, the energy industry is expected to continue investing in the build out and management of their compliance programs to demonstrate a more proactive stance to managing their obligations. Reliability, the prevention of market manipulation, and the promotion of competitive markets that are nondiscriminatory will remain at the forefront of compliance efforts of both regulatory agencies and the companies that they regulate.

Enterprise Risk

The energy and resources industry is facing a number of new and reoccurring challenges, such as a slow economic recovery, reduced energy consumption, decreased commodity prices, increased regulatory activities and requirements (NERC, FERC, energy efficiency resource standards, renewable portfolio standards, etc.), pressure to reduce costs, unsatisfactory rate case results, and aged infrastructure failure, just to name a few.

In response to these challenges, companies are seeking innovative ways to manage their many existing and emerging risks. Interest in and support of enterprise risk management (ERM) programs continue to grow among executives. Organizations are leveraging and expanding their ERM programs to establish an integrated framework to help evaluate, prioritize, and proactively monitor their risks.

In addition, a number of companies are integrating their ERM initiatives with strategic planning programs. This integration enables companies to perform a more efficient and effective prioritization of their investments, capital programs, and maintenance projects. Because the realignment of corporate strategies has placed a greater emphasis on core businesses, aged infrastructures, weather and environmental concerns, and increased regulatory attention, certain ERM programs have already begun dedicating more time and resources to operational risks this year.

Another emerging trend is the integration of ERM and emergency management (EM) programs. Management teams are seeking a more complete and transparent correlation between risks and the underlying consequences. This integration allows entities to apply a risk-based approach in designing and scheduling EM drills and exercises as well as in managing scarce resources. Furthermore, the fusion of ERM and EM data provides the foundation for ongoing assessment and monitoring of a company's readiness/preparedness on the basis of the results and feedback from drills and exercises that simulate actual emergency events.

As a result, this is a great time to be a part of the industry. Events and activities within the next few years may transform and call for a reassessment of existing business models. The nuclear renaissance; the evolution of biomass, solar, and wind technologies; a decrease in commodity prices; an aging workforce; increased customer focus on conservation; the modernization of the electrical grid; and stringent regulatory requirements may have a tremendous impact on reshaping the future of the sector.

Construction Risk Management

The *Wall Street Journal* recently published an eight-page report on power investing in which it described the complexities of today's power industry and the myriad power generation options available to P&U companies, including natural gas, solar photovoltaic, solar thermal, coal wind, geothermal, natural gas (combined cycle), and nuclear. Today, P&U companies are faced with difficult investment decisions affected by fuel costs, environmental concerns and legislation, operating costs, and capital investment and construction risk. While the downturn in the global economy has weakened the demand for additional energy resources, many P&U companies are making significant investments in new power generation facilities or refurbishing existing facilities to prepare for the future. In some cases, the magnitude of their investment is so great it may materially affect their financial performance. For example, Standard & Poor's has estimated that the average cost for a new nuclear plant is above $7.5 billion, and the time required to plan, design, and construct such a plant is measured in years.

Not only are the capital investments significant, but there may also be significant cost and financial implications resulting from the associated impact of unforeseen construction risks. Because of their scale and complexity, these large capital projects present numerous risks ranging from typical cost overruns, schedule delays, and safety and quality concerns to the complex risks inherent in new designs and unproven technology, among others. Some recent large capital power construction projects have experienced over a 50 percent increase construction related costs.

For these reasons, many P&U companies have increased their awareness of and focus on construction risk management, implementing strict oversight processes, and advanced risk management techniques. The traditional risk management process (i.e., identify, evaluate, respond, and monitor) along with risk management tools, including risk registers, risk response plans, and advanced probabilistic analyses, are helping companies gain a better understanding of critical construction risks so companies may proactively address and mitigate them. However, a stand-alone risk management approach produces effective results. The successful implementation of construction risk management requires integration with other key processes, including cost management, schedule management, change management, and contingency allocation. Given the significant increase in capital investments, P&U companies are taking steps in the right direction to advance the maturity of their risk management capabilities; however, effective construction risk management requires an accelerated learning curve and a cultural shift such that employees buy into the principles of construction risk management as a core project management process.

Environmental, Health, and Safety Management

Damages to regional economies, local businesses, and natural resources can carry a heavy price-tag. The costs go beyond the ultimate assessment of liabilities and include increased spending related to preparing for and responding to legal and regulatory investigations as well as the reputational impact that can result from a significant environmental disaster. In a year when life along the gulf coast has changed forever, various stakeholders, including legislators, regulatory agencies, emergency responders, and the public, have increasingly challenged the industry to ensure that appropriate safety measures are employed to prevent environmental and other disasters.

The 2010 oil spill in the Gulf of Mexico brought an onslaught of criticism to the energy and resources industry. The spill stemmed from a sea-floor oil gusher that resulted from the April 2010 Deepwater Horizon drilling rig explosion that killed 11 platform workers and continued to dump millions of barrels of oil into the Gulf for several weeks. Reactions to the Deepwater Horizon oil spill ranged from blame and outrage at the damage caused by the spill to calls for greater accountability on the part of the U.S. government and energy companies, including new legislation dealing with preventative security and cleanup improvements.

After the oil spill in the gulf, a rupture in a Michigan pipeline released an estimated 819,000 gallons into a Lake Michigan tributary. Heavy rains caused the river to overtop existing dams and carried oil 30 miles downstream on the Kalamazoo River.

A natural gas pipeline explosion in San Bruno, California, has increased scrutiny of pipeline safety standards and pipeline inspections. The National Transportation Safety Board, the federal agency responsible for investigating natural gas pipeline incidents, has reported that it could be up to 18 months before a report is issued determining the cause. In the meantime, a growing awareness of pipeline safety has emerged and regulatory pressure on utilities to expand inspections and upgrade or replace aging pipelines will most likely increase.

While the full extent of the fallout from these incidents remains to be seen, it is likely that federal, state, and local agencies will reexamine their oversight of stakeholders in the energy and resources industry to ensure proper environmental, health, and safety management.

Permanent Demand Destruction

According to the Energy Information Administration's *Annual Energy Outlook 2010* ("AEO 2010"), the 2009 level of energy consumption per person was the lowest it has been since 1968. In light of the economic environment during the past two years, it is no surprise that demand for regulated services was down in 2009. P&U companies have been looking at the impact of the recession, and more specifically, the reasons why utilities experienced a loss of demand. Most companies attributed a significant portion of the drop to "involuntary efficiency," whereby customers were conserving and saving because they felt the pinch when they received their bills. Others considered "voluntary efficiency" a primary driver for the decrease in demand. This type of efficiency is a result of energy conservation programs as well as technological advances in the next generation of equipment and appliances that require less energy consumption to operate.

As the economy continues to recover, only the demand related to involuntary efficiency is likely to return; the demand tied to voluntary efficiency will most likely be permanently lost. Consequently, companies are becoming increasingly concerned about how much demand will be regained. This concern is compounded by anticipated future losses in demand as a result of the smart grid stimulus funds directed at energy efficiency and ongoing technological advances. As noted in the AEO 2010 reference case, energy use per capita is projected to increase slightly in the next few years as the economy continues to rebound but is expected to begin "declining in 2013 as higher efficiency standards for vehicles and lighting begin to take effect. [Reference omitted] From 2013 to 2035, energy use per capita declines by 0.3 percent per year on average."

The electric sector has been a growth business for as long as anyone can remember, and most P&U companies have long operated under the assumption that such growth would continue. Accordingly, a period of declining or negative growth would require companies to challenge their corporate strategies.

Section 2
SEC Update

This section summarizes recent accounting and reporting guidance from the SEC and related guidance affecting SEC registrants.

Oil and Gas Reporting Updates

On December 29, 2008, the SEC approved revisions to its oil and gas reporting requirements to reflect the significant changes that have occurred in the industry over the past 25 years. The final rules allow for more comprehensive disclosures of off-balance-sheet information to help investors understand the value of their investments in oil and gas companies.

See last year's Energy and Resources update for more detailed information about these approved revisions to oil and gas reporting requirements. The following discussion outlines changes since last year's update.

SEC Releases SAB 113

On October 30, 2009, the SEC's Office of the Chief Accountant issued SAB 113. The SAB updates the guidance on how the SEC staff interprets accounting rules related to the oil and gas industry and revises SAB Topic 12 to conform to SEC Rule 33–8995 on modernization of oil and gas reporting. The principal revisions include (1) changing the price entities use in determining quantities of oil and gas reserves, (2) eliminating the option for entities to use post-quarter-end prices to evaluate write-offs of excess capitalized costs under the full-cost method of accounting, (3) removing the exclusion of unconventional oil and gas extraction methods as oil and gas producing activities, and (4) removing certain questions and interpretative guidance that are no longer necessary.

FASB Updates Oil and Gas Reserve Estimation and Disclosure Requirements

On January 6, 2010, the FASB issued ASU 2010-03, which aligned the current reserve estimation and disclosure requirements of ASC 932 with the requirements in SEC Rule 33–8995. In addition, the ASU expanded the disclosures required for equity method investments.

ASU 2010-03 is effective for entities with annual reporting periods ending on or after December 31, 2009, except for entities that become subject to the disclosure requirements of ASC 932 solely as a result of the ASU's amendment to the definition of significant oil- and gas-producing activities. Those entities may adopt the ASU's guidance for annual periods beginning on or after December 31, 2009. Early adoption is not permitted.

SEC Staff Issues "Oil and Gas Reporting Modernization — A Small Entity Compliance Guide"

In January 2010, the SEC staff published a compliance guide for small entities (as defined in Section 212 of the Small Business Regulatory Enforcement Fairness Act of 1996, as amended). The guide summarizes and explains the revisions released by the SEC to its oil and gas reporting disclosure requirements that previously were dispersed in Regulation S-K and Regulation S-X as well as in Industry Guide 2. Topics covered in the guide include early compliance, changes to oil and gas definitions in Rule 4-10 of Regulation S-X, consolidation of disclosure requirements in Subpart 1200 of Regulation S-K, and other significant items such as MD&A guidance, ceiling test limitation for capitalized costs under the full cost method, and transitional accounting guidance for changes that result from applying the amendments.

Proxy, Risk, Compensation, and Corporate Governance Guidance Updates

SEC Observations and Expectations About Executive Compensation Disclosures

In a speech at the November 2009 Fourth Annual Proxy Disclosure Conference in San Francisco, Shelley Parratt, deputy director in the SEC's Division of Corporation Finance, discussed the SEC's observations on the 2009 executive compensation disclosures and what to expect from the 2010 comment process regarding executive compensation. The 2009 observations highlighted the following two areas on which companies should focus their attention: (1) analysis of how and why entities made their compensation decision and (2) performance targets.

The 2009 observations were described as publicly discussed themes, and it was noted that the SEC expects entities and their advisers to understand the rules and apply them thoroughly. It was further stated that for 2010, any company that waits to receive staff comments to comply with the disclosure requirements should be prepared to **amend** its filings if it does not materially comply with the rules.

SEC Approves Enhanced Disclosure About Risk, Compensation, and Corporate Governance

On December 16, 2009, the SEC approved Rule 33-9089, which was designed to improve disclosure about compensation and corporate governance. Among other improvements, the new disclosure requirements enhance the information provided in annual reports and proxy and information statements to better enable shareholders to evaluate the leadership of public companies. During the past few years, investors have increasingly focused on corporate accountability and have expressed the desire for additional information that would enhance their ability to make informed voting and investment decisions. The rule requires disclosures in proxy and information statements about:

- The relationship of a "company's compensation policies and practices [to] risk management."
- The background and "qualifications of directors and nominees."
- "[L]egal actions involving a company's executive officers, directors, and nominees."
- "[C]onsideration of diversity in the process by which candidates for director are considered for nomination."
- "[B]oard leadership structure and the board's role in the oversight of risk."
- Stock and option awards granted to company executives and directors.
- "[P]otential conflicts of interests of compensation consultants."

The rule became effective on February 28, 2010.

SEC Issues New Interpretations on Proxy Disclosure Enhancements

To address various implementation and transitional questions as a result of the amendments in SEC Rule 33-9089, in December 2009 and January, February, and March 2010, the SEC also issued various Regulation S-K C&DIs on executive compensation disclosures specifically related to, among others, the following areas in Regulation S-K:

- Item 401, "Directors, Executive Officers, Promoters, and Control Persons."
- Item 401(e), Required disclosure regarding director business experience.
- Item 402(a), "Executive Compensation; General."
- Item 402(c), "Executive Compensation; Summary Compensation Table."
- Item 402(s), "Executive Compensation; Narrative Disclosure of the Registrant's Compensation Policies and Practices as They Relate to the Registrant's Risk Management."
- Item 407, "Corporate Governance."
- Requirements to include Item 402 disclosure on executive compensation in a registration statement before it can be declared effective.
- Reporting certain equity awards in the executive compensation tables required by Regulation S-K.

The SEC also updated its Exchange Act Form 8-K C&DIs and added question 121A.01, which provides guidance on calculating the four-business-day filing period for Item 5.07 of Form 8-K related to the submission of matters to a vote of security holders.

Technical Corrections to Proxy Disclosure Enhancements

On February 23, 2010, the SEC issued Release 33-9089A, which makes technical corrections to the disclosure requirements in Rule 33-9089. The technical corrections are also effective February 28, 2010. The changes included the following:

- Rule 33-9089 required that that for shareholder meetings held on or after February 28, 2010, registrants must report all shareholder voting results in Item 5.07 of Form 8-K rather than in Item 4, "Submission of Matters to a Vote of Security Holders," and that the other Items would move up numerically (i.e., in Form 10-K, Item 5 in Part II would have become Item 4). However, Release 33-9089A amended Forms 10-K and 10-Q by removing and reserving Item 4 so that the Items in Forms 10-Q and 10-K will retain their current numbering (i.e., Form 10-K, Item 5 of Part II will remain Item 5; Management's Discussion and Analysis of Financial Condition and Results of Operations will remain Item 7; and so forth). This was done to prevent confusion regarding references to the Item numbers in existing professional literature.
- Release 33-9089A made three changes to Form 8-K, including the addition of an instruction, which corresponds to an instruction contained in Forms 10-Q and 10-K, that allows certain wholly owned subsidiaries to omit the disclosure of shareholder voting results.

SEC Staff Issues "Proxy Disclosure Enhancements — A Small Entity Compliance Guide"

The SEC staff published a compliance guide for small entities (as defined under Section 212 of the Small Business Regulatory Enforcement Fairness Act of 1996, as amended) that summarizes and explains the requirements of the amendments to proxy and informational statement disclosures. Topics covered in the guide include new director and nominee disclosure, expanded disclosure about legal proceedings involving executive officers, directors, and nominees for director, new disclosure of how diversity is considered in the director nomination process, new disclosure about board leadership structure and the board's role in risk oversight, revised disclosure in the summary compensation table, new disclosure about potential conflicts of interests of compensation consultants, and faster reporting of shareholder voting results.

Effects of the Dodd-Frank Wall Street Reform and Consumer Protection Act on Executive Compensation and Corporate Governance

The enacted legislation includes a variety of executive compensation and corporate governance provisions. For example, it requires public companies to allow shareholders to vote on the compensation of named executive officers and to approve any compensation "agreements or understandings" paid to these officers in connection with "an acquisition, merger, consolidation, or proposed sale or other disposition of all or substantially all the assets of an issuer," unless such agreements or understandings have been previously subject to a shareholder vote. These are commonly referred to as "say-on-pay" and "say on golden parachutes" provisions.

The legislation also directed the SEC to establish rules requiring that entities, in the event of an accounting restatement attributable to material noncompliance with financial reporting requirements, develop policies mandating the recovery (or "clawback") of "excess" incentive compensation paid to executive officers under incentive plans regardless of whether the executive officer was involved in the misconduct that led to the restatement.

In addition, under the legislation, the SEC:

- Must issue rules directing national securities exchanges and associations to require the independence of all members of a listed entity's compensation committee.
- Must issue rules requiring entities to disclose whether employees and directors are allowed to hedge the value of any of the company's equity securities they own.
- May issue requirements that, if met, would permit shareholders to nominate directors to include in an entity's proxy materials (otherwise known as "proxy access").

Climate-Change Disclosures

SEC Approves Interpretive Guidance on "Climate-Change" Disclosures

At its January 27, 2010, open meeting, the SEC voted 3 to 2 to approve an interpretive release on providing "climate-change" disclosures. The interpretive guidance will not create new disclosure requirements; rather, it will clarify "certain existing disclosure rules that may require a company to disclose the impact that business or legal developments related to climate change may have on its business."

The release addresses four climate-change-related topics that registrants should consider when assessing what information to provide under existing SEC disclosure requirements:

- The impact of existing and potential litigation or regulation.
- The effect on the business of international accords and treaties related to climate change and governing greenhouse gas emissions.
- The actual and potential indirect consequences of climate-change-related regulations or business trends (the release includes examples of indirect consequences).
- The actual and potential impacts of the physical effects of climate change on the business.

The interpretive release also highlights the SEC's existing rules that may require disclosure of material climate-change matters, such as the following Items of Regulation S-K:

- Item 101, "Description of Business."
- Item 103, "Legal Proceedings."
- Item 303, "Management's Discussion and Analysis of Financial Condition and Results of Operations."
- Item 503, "Prospectus Summary, Risk Factors, and Ratio of Earnings to Fixed Charges."

In addition to the disclosure requirements of Regulation S-K and Regulation S-X, Securities Act Rule 408, and Exchange Act Rule 12b-20 require a registrant to disclose "such further material information, if any, as may be necessary to make the required statements, in light of the circumstances under which they are made, not misleading."

The SEC's Investor Advisory Committee indicated it will consider climate-change disclosures in its role as an adviser to the SEC. Disclosures on climate change matters are also expected to be the subject of a public roundtable planned by the Commission. On the basis of insights gained from the Investor Advisory Committee and the roundtable, the SEC plans to determine whether additional guidance or rulemaking on climate-change disclosures is necessary.

Core Disclosure Project and Use of Non-GAAP Financial Measures

2009 AICPA National Conference on Current SEC and PCAOB Developments

At the 2009 AICPA National Conference on Current SEC and PCAOB Developments (the "AICPA Conference"), representatives from the Commission, particularly those in the Division of Corporation Finance, emphasized the importance of (1) their core disclosure project and (2) embracing simplification and consistency in communications with investors in the upcoming reporting season. The SEC's core disclosure project will comprise a comprehensive review of the current disclosure requirements, with goals to modernize disclosures and eliminate redundancy. The representatives indicated that the focus should be on obtaining the right disclosure, not more disclosure, noting that it imposed a huge burden on investors to wade through expansive disclosure to find what's important.

In keeping with the SEC staff's focus on enhancing disclosures for the benefit of investors, it was also noted that the staff was conducting a review of the current interpretations on non-GAAP financial measures. The goal of the staff's review was to ensure that the interpretations are not read in a manner that "causes companies to keep key information out of their filings, which they are otherwise using to tell investors their story [through communications such as earnings calls and press releases] and which they believe is the most meaningful indicator of how they are doing." The staff noted that there was an inconsistency between (1) the focus of information on company Web sites, earnings releases, and presentations to analysts and (2) disclosures in their filings. The staff also noted that registrants may be omitting non-GAAP financial measures from their filings because of concerns about future SEC staff comments and indicated that it plans to revise the guidance before year-end so that calendar-year-end companies could consider it in preparing their annual filings.

SEC Issues Updated C&DIs on Non-GAAP Financial Measures

On January 11 and 15, 2010, the SEC's Division of Corporation Finance issued new C&DIs on the use of non-GAAP financial measures. The new guidance gives registrants more flexibility to disclose non-GAAP measures in filings with the SEC. The C&DIs replace the interpretative guidance in the SEC staff's "Frequently Asked Questions Regarding the Use of Non-GAAP Measures" (the "FAQs"), which was issued in June 2003, but the rules on non-GAAP financial measures (Regulation G and Item 10(e) of Regulation S-K) were not amended. The C&DIs include some new and revised interpretations and exclude certain transition issues that had been covered in the FAQs. The SEC staff has also updated the FRM section on non-GAAP financial measures.

In line with the SEC staff's remarks at the 2009 AICPA Conference, many of the changes reflected in the C&DIs were the result of a recent SEC staff review of its interpretations of non-GAAP financial measures. While registrants frequently included non-GAAP financial measures in press releases, many had been reluctant to include these same measures in filed documents because of some of the restrictions in the now rescinded FAQs. As a result, the staff made some key changes. For example, it revised the guidance on nonrecurring, infrequent, or unusual items in FAQs 8 and 9 and replaced it with C&DI 102.03.

C&DI 102.03 states the following:

> **Question:** Item 10(e) of Regulation S-K prohibits adjusting a non-GAAP financial performance measure to eliminate or smooth items identified as non-recurring, infrequent or unusual, when the nature of the charge or gain is such that it is reasonably likely to recur within two years or there was a similar charge or gain within the prior two years. Is this prohibition based on the description of the charge or gain, or is it based on the nature of the charge or gain?
>
> **Answer:** The prohibition is based on the description of the charge or gain that is being adjusted. It would not be appropriate to state that a charge or gain is non-recurring, infrequent or unusual unless it meets the specified criteria. The fact that a registrant cannot describe a charge or gain as non-recurring, infrequent or unusual, however, does not mean that the registrant cannot adjust for that charge or gain. Registrants can make adjustments they believe are appropriate, subject to Regulation G and the other requirements of Item 10(e) of Regulation S-K.

The following example illustrates application of the guidance in C&DI 102.03. Registrant A incurs an impairment charge in 2009 that it believes is an appropriate adjustment to a non-GAAP financial performance measure. Management believes that it is reasonably likely that this impairment charge will recur within two years. Management may make the adjustment to the non-GAAP financial performance measure for the impairment charge (subject to Regulation G and the other requirements in Item 10(e)), but it cannot describe the charge as nonrecurring, infrequent, or unusual because it does not meet the specified criteria.

Note that C&DI 102.03 also removes other disclosure requirements that were in FAQ 8, such as the economic substance behind management's decision to use such a measure.

Other noteworthy items include the addition of four C&DIs on topics that had not been addressed in the FAQs. The following are highlights of two of the new C&DIs:

- C&DI 102.04 clarifies that a registrant is not prohibited from "disclosing a non-GAAP financial measure that is not used by management in managing its business."
- C&DI 102.11 clarifies that "a registrant [may] present an adjustment 'net of tax' when reconciling a non-GAAP performance measure to the most directly comparable GAAP measure" provided that it makes certain disclosures.

As noted above, the rules on non-GAAP financial measures (Regulation G and Item 10(e)) were not amended; accordingly, registrants should continue to provide the disclosures required by Item 10(e).

Dodd-Frank Wall Street Reform and Consumer Protection Act

Financial Reporting Implications of the Dodd-Frank Wall Street Reform and Consumer Protection Act

The Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Act" or "Dodd-Frank Act") was signed into law on July 21, 2010. The Act aims to (1) promote U.S. financial stability by "improving accountability and transparency in the financial system," (2) put an end to the notion of "too big to fail," (3) "protect the American taxpayer by ending bailouts," and (4) "protect consumers from abusive financial services practices." To achieve these broad objectives, the Act includes many provisions whose magnitude will not be fully appreciated until regulators have implemented them by adopting new rules and regulations. The legislation requires regulatory agencies (including in many instances the SEC) to create numerous new rules, conduct various new studies, and issue several new periodic reports.

While a primary focus of the Act is on financial institutions, some of its provisions affect registrants more broadly. The following summarizes certain notable aspects of the Act that might have financial reporting implications:

- Permanent exemption from Section 404(b) of the Sarbanes-Oxley Act of 2002 (see below).
- Enhancements to the asset-backed securitization process.
- Greater oversight of credit rating agencies (see below).
- A new systematic risk regulator.
- Changes to SEC authority and operations.
- A variety of executive compensation and corporate governance provisions (see the Proxy, Risk, Compensation, and Corporate Governance Guidance Updates section above for more information).
- Regulation of OTC derivatives.

The Act calls for the SEC to undertake a significant amount of rulemaking and special studies, and regulators are expected to issue several such rules and studies over the coming months. One example is SEC Rule 33-9142, issued on September 15, 2010, which exempts nonaccelerated filers from Sarbanes-Oxley Section 404(b). The exemption is effective immediately and was issued in accordance with new Section 404(c) of the Sarbanes-Oxley Act, enacted as part of the Act.

For additional information, see Deloitte's August 12, 2010, *Head's Up* on the Act.

SEC Issues C&DIs Related to Use of Credit Ratings

The passage of the Act eliminated the exemption precluding a registrant from needing to name a credit rating agency as an expert and obtain its consent when information about credit ratings was included in a registration statement offering asset-backed securities. Therefore, upon enactment, an issuer that included a credit rating in a registration statement would have been subject to the requirement to obtain a consent from the rating agency.

However, asset-backed issuers had difficulty obtaining credit-rating-agency consents to comply with the Act and thus issuing securities. As a result, on July 22, 2010, the SEC staff issued a "no action" letter allowing asset-backed issuers to omit, until January 24, 2011, credit ratings from registration statements filed with the SEC.

In addition, during July 2010, the SEC's Division of Corporation Finance issued new C&DIs on a registrant's use of credit ratings for issuers. The new C&DIs provide interpretive guidance on when a registrant would be required to name a credit agency as an expert and obtain its consent in conjunction with the use of credit rating information in a registration statement.

For example, the C&DIs point out that "some issuers note their ratings in the context of a risk factor discussion regarding the risk of failure to maintain a certain rating and the potential impact a change in credit rating would have on the registrant." In that case, and in disclosing other "issuer disclosure-related ratings information" (e.g., changes to a credit rating, the liquidity of the registrant, the cost of funds for a registrant, or the terms of agreements that refer to credit ratings), the registrant would not be required to obtain a consent from the credit rating agency.

The following C&DI sections were added or updated:

- Section 198, Rule 401, "Requirements as to Proper Form."
- Section 233, Rule 436, "Consents Required in Special Cases."

In Section 255, Rule 501 — Definitions and Terms Used in Regulation D, Question 255.13 was withdrawn.

Shareholder Approval of Executive Compensation and Golden Parachute Compensation

On October 18, 2010, the SEC issued for comment a proposed rule on "say-on-pay" and "say on golden parachute" provisions under Section 951 of the Act. The rule would require companies to conduct separate shareholder advisory votes to approve the compensation of executives and to determine how often such advisory votes would occur. In addition, the rule would require 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. Comments were due by November 18, 2010.

Other SEC Guidance

CAQ Publishes Alert on Statement 167 Practice Issues

On April 9, 2010, the CAQ published Alert 2010-20, which outlines the SEC staff's views on certain Statement 167 (codified as ASC 810-10) practice issues. The topics discussed in the alert include filing registration statements after adoption of Statement 167; applying the transition provisions of Statement 167; pro forma requirements; and considerations under Rule 3-05, Rule 3-14, and Form 8-K regarding the adoption of Statement 167.

CAQ Publishes Alert on ICFR Requirements for Entities Newly Consolidated Under Statement 167

On April 19, 2010, the CAQ published Alert 2010-21, which outlines the SEC staff's views on ICFR requirements for an entity newly consolidated under Statement 167 (codified as ASC 810-10). The alert also discusses the applicability of Questions 1 and 3 of the SEC staff's frequently asked questions, "Management's Report on ICFR," after an entity's adoption of Statement 167.

SEC Issues Proposed Rule and Interpretive Release to Enhance Short-Term Borrowing Disclosures

On September 17, 2010, the SEC issued a proposed rule on short-term borrowings disclosure, and a companion interpretive release. The SEC's objective in proposing the rule is to improve transparency of registrants' short-term borrowings by creating a new section within Liquidity and Capital Resources that would contain tabular information about a registrant's short-term borrowings and narrative disclosures, and analysis of short-term borrowings, within MD&A. In addition, the rule would increase existing disclosures for financial companies and add a new disclosure requirement on short-term borrowings that would apply to all other public entities.

The interpretive release would provide guidance on the current requirements within MD&A about liquidity and capital resources disclosures.

Comments on the proposed rule are due by November 29, 2010. The guidance in the interpretative release was effective upon its publication in the *Federal Register*.

For additional information, see Deloitte's September 24, 2010, *Heads Up* on the proposed rule and interpretive release.

SEC Issues Proposed Rules on ABS

On April 7, 2010, the SEC issued for public comment a proposed rule on asset-backed securities (ABS). The proposal makes significant revisions to SEC Regulation AB (which governs ABS offerings) and other rules regarding the offering process, disclosure, and reporting for ABS. According to Chairman Mary Schapiro, the proposed rules would "fundamentally revise the regulatory regime for asset-backed securities."

Some of the provisions of the proposed rule include:

- Revisions to the "filing deadlines for ABS offerings to provide investors with more time" to make investment decisions.
- Elimination of "current credit ratings references in shelf eligibility criteria" and establishment of new shelf eligibility criteria for ABS.
- Requirement that "prospectuses for public offerings of [ABS] and ongoing [periodic] reports contain specified asset-level information about each of the assets in the pool . . . in a tagged data format using eXtensible Markup Language," except for some limited exceptions.
- "[N]ew information requirements for the safe harbors for exempt offerings and resales of [ABS]."

In October 2010, the SEC issued two additional proposed rules, Release 33-9148 and Release 33-9150, on ABS offerings required under Sections 943 and 945 of the Act, respectively. In Release 33-9148, the SEC proposes to (1) require entities that securitize ABS "to disclose fulfilled and unfulfilled repurchase requests across all transactions" and (2) "require nationally recognized statistical ratings organizations to include certain information regarding warranties and enforcement methods available to investors" of ABS offerings when credit ratings accompany the offering.

In Release 33-9150, the SEC proposes to require (1) issuers of ABS "to perform a review of the assets underlying the ABS" and "to disclose the nature of [their] review of the assets and the findings" and (2) issuers or underwriters of ABS to "disclose the third-party's findings and conclusions," including certain disclosures about third-party due diligence providers, when a third party is engaged to perform the review of underlying assets on the issuer's behalf.

The comment period for both proposals ended on November 15, 2010.

Highlights of CAQ SEC Regulations Committee Meetings With SEC Staff

The 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 the following meetings were released during the last year:

September 2009 Meeting

Highlights included:

- Current financial reporting matters:
  - Disclosures related to goodwill and goodwill impairment and non-GAAP financial measures.
  - Staff filing review and comment process.
- Implementation and interpretation of recent SEC releases:
  - XBRL — The SEC staff provided a summary of observations related to XBRL exhibits submitted by the first transition group of registrants.
- New or pending accounting standards and pronouncements:
  - Subsequent events (ASC 855).
- Current practice issues:
  - Updating requirement when an acquired business of "major significance" has been included in the registrant's audited financial statements for at least nine months.
  - Rule 3-14 financial statement requirements.
  - Variable interest entity reconsideration events.

April 2010 Meeting

Highlights included:

- Current financial reporting matters
  - Year-end reporting challenges for 2009 and matters discussed at the AICPA Conference.

- Staff filing review and comment process on the use of preclearance letters for IPOs.
    - Effects of the new health care legislation and disclosures in interim financial statements of newly adopted accounting standards.
- Implementation and interpretation of recent SEC releases
    - IFRSs — Commission statement in support of convergence and global accounting standards.
    - ICFR — Section 404(b).
    - Commission guidance on disclosure related to climate change.
- New or pending accounting standards and pronouncements:
    - Subsequent events (ASC 855).
    - ICFR reporting considerations and the initial consolidation of a variable interest entity.
- SEC staff and other initiatives
    - Updates to the FRM, C&DIs on non-GAAP measures, and the "Dear CFO" letter on repurchase agreements.
- Current practice issues
    - Calculating book value per share after adopting ASC 810.
    - Applicability of disclosure requirements of Item 3(f) of Form S-4 when the target is a reporting company that is significant at or below the 20 percent level.
    - General partner balance sheet in oil and gas limited partnership registration statement.
    - XBRL transition provisions.

June 2010 Meeting

Highlights included:

- Current financial reporting matters:
    - Effect of current events on disclosures.
    - Cheap stock.
    - Contingency disclosures.
    - Domestic companies with a majority of operations outside the United States.
- Implementation and interpretation of Recent SEC releases:
    - Section 404(b) for non-accelerated filers.
    - XBRL.

- SEC staff and other initiatives:
    - o Updates to the FRM and C&DIs on non-GAAP financial measures and Regulation S-K.
    - o A possible delay in the SEC's planned core disclosure project.
- Current practice issues
    - o Summarized financial information of equity investees.
    - o PCAOB registration for auditors of equity method investees.
    - o Impact on Article 11 pro forma income statement of changes in the fair value of contingent consideration related to a business combination.
    - o Pro forma income information for a business combination — computation and presentation in MD&A.

September 2010 Meeting

Highlights included:

- Current financial reporting matters:
    - o Implications of the Dodd-Frank Act.
    - o Loss contingency disclosures.
    - o Non-GAAP financial measures.
    - o Article 11 pro forma financial information for an acquired foreign business.
    - o Venezuela.
- IFRS work plan and XBRL.
- SEC staff and other initiatives:
    - o Updates to the FRM and C&DIs on consents from securities ratings agencies.
- Current practice issues:
    - o Financial statements of "lower tier" companies.
    - o Applicability of the disclosure requirements of Item 3(f) of Form S-4 when the target is a reporting company that is significant at or below the 20 percent level.

Since the meetings, and as noted throughout this section, the SEC staff has taken action on a number of these issues, including revising the FRM (see below), issuing C&DI and CAQ alerts, and making several announcements.

Updates to the FRM

The FRM, released in December 2008 by the SEC's Division of Corporation Finance, superseded the Division of Corporation Finance's *Accounting Disclosure Rules and Practices: An Overview* (also known as the *SEC Staff Training Manual*). The FRM provides helpful insight into how the SEC staff interprets and applies SEC rules and regulations.

During December 2009 and March and July 2010, the SEC staff revised the FRM. Revisions included new information and updates to previously released versions. Noteworthy changes include:

- Updates to Topic 6, *Foreign Private Issuers and Foreign Businesses*, and Topic 8, *Non-GAAP Measures of Financial Performance, Liquidity and Net Worth*.
- Changes related to PCAOB deregistration.
- Updates to references as a result of the *FASB Accounting Standards Codification*.
- The addition of Section 9500, *Critical Accounting Estimates — Goodwill Impairment*.
- Clarification in the staff's guidance on whether limited partnership registrants must include the balance sheet of a general partner in certain filings.
- Expanded interpretive guidance on calculating significance for business acquisitions involving successors to predecessor businesses, calculating significance for dispositions, and treatment of transaction costs in pro forma financial statements.

Users should be sure to refer to the most current version of the FRM.

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.

Below is a list of frequent SEC comment letter topics for the oil and gas and the P&U sectors. For additional information related to these topics and to see other SEC comment letter topics, refer to Deloitte's *SEC Comment Letters on Domestic Registrants — A Closer Look*.

- 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.

Section 3
International Financial Reporting Standards

IFRSs are on the minds of many at P&U sector companies as we continue to monitor the ongoing international debate, the continued efforts of the SEC to conduct its work plan (see below) activities leading up to a decision about whether to mandate IFRSs for U.S. companies, and the convergence efforts of the IASB and FASB (the "boards").

SEC Update

In November 2008, the SEC issued its proposed IFRS Roadmap ("Roadmap") outlining milestones that, if achieved, could lead to mandatory transition to IFRSs, potentially as early as December 2014. In exposing the Roadmap for comment, the SEC sought input on a number of areas, including the use of IFRSs by U.S. issuers, the SEC's overall approach and considerations, proposed technical amendments to the SEC's rules and regulations, and the standard-setting process under IFRSs. The Roadmap also presented an opportunity for the SEC to decide, on the basis of progress measured against a set of milestones, on potential mandatory adoption of IFRSs in 2011.

Over 200 comment letters on the Roadmap were submitted to the SEC from a broad range of interested parties, including investors, issuers, regulators, standard setters, and representatives from academia and from the accounting and legal professions as well as other fields. The comments generally indicated support for the goal of a single set of high-quality globally accepted accounting standards, although views differed about the best approach going forward and were split between continuing current convergence efforts and going forward with a "big bang" wholesale adoption of IFRSs. Respondents also raised other concerns about the structural and operational issues involved in making the transition to IFRSs and about areas similar to those the SEC itself had identified as milestone considerations, such as the maturity and completeness of IFRSs, the independence of the global standard setter, the time frame needed for constituents to adequately prepare, and the overall costs of transition.

After considering the comments and insights it received about the Roadmap, the SEC (after much anticipation) unanimously approved at its open meeting on February 24, 2010, a public statement expressing the SEC's strong commitment to the development of a single set of high-quality globally accepted accounting standards. The SEC noted that as the activities of investors, companies, and markets become increasingly global, use of a single set of high-quality global standards will facilitate cross-border capital formation and help give investors the comparable financial information they need to make informed decisions about investment opportunities around the world. The Commissioners also affirmed that IFRSs are "best positioned" to be that set of standards for the U.S. market and outlined the SEC's next steps to determine whether to incorporate IFRSs into the financial reporting system for U.S. issuers. The statement also emphasized the importance of the boards' convergence efforts (discussed below).

In recognition of the other structural, operational, and transitional issues raised in the comment letters, the statement directed the SEC staff to execute a "work plan" to provide the SEC with appropriate information to make a well-informed decision about the use of IFRSs. After completing the work plan's activities, and in recognition of the status of the ongoing convergence projects, the SEC will reconsider whether to incorporate IFRSs into the U.S. financial reporting system. The statement indicates that the SEC will make this determination in 2011, in line with the timeline in the Roadmap. The statement notes that if in 2011 the SEC votes to incorporate IFRSs into the financial reporting system for U.S. issuers, sufficient transition time would be allowed, with U.S. issuers reporting under such a system no earlier than 2015.

While the SEC did not provide definitive dates for the U.S. adoption of IFRSs, the February 2010 statement marked another step toward the use of IFRSs, and the work plan itself demonstrates the SEC's level of commitment to moving forward with IFRSs for U.S. issuers.

A few developments that took place after the SEC's February 2010 open meeting are also worth noting. On May 18, 2010, in her presentation to the annual conference of the CFA Institute, SEC Chairman Mary Schapiro countered several "myths" about the SEC and IFRSs and further reaffirmed the SEC's commitment to developing a "single set of high-quality, globally-accepted accounting standards which will benefit U.S. investors and investors around the world."

Chairman Shapiro responded to the myth that the "SEC's commitment to global accounting standards is not as strong as it should be" by stating:

> Let's put this one to rest, right away. And, I can do that by citing the official text of our Commission Statement in Support of Convergence and Global Accounting Standards. In February we clearly stated: "The Commission continues to believe that a single set of high-quality globally accepted accounting standards will benefit U.S. investors and that this goal is consistent with our mission of protecting investors, maintaining fair, orderly, and efficient markets, and facilitating capital formation."

She also responded to the myth that the "U.S. may be committed, but it's dragging its feet regarding adoption of IFRS" by noting:

> This too is wrong. To be clear, while I strongly believe in our commitment to high quality accounting standards, I believe just as strongly that this commitment is only the beginning of the discussion, not the end. The convergence process is critical to the incorporation of IFRS into the U.S. market. . . . While redoubling efforts to achieve the goal of convergence in a timely manner is important, a convergence effort that fails to take into account the due processes of the standard setting bodies will not serve investors well in the long run. . . . We are committed to convergence. But we are committed, above all, to a convergence exercise that yields high-quality improvements to accounting standards. And the fact is, we are moving forward. We are executing on a comprehensive work plan, dedicating significant resources to it and providing periodic progress reports on it.

In addition, in August 2010, the SEC released two Requests for Comment on a number of topics related to its ongoing work plan activities, in which it asked for views on the following topics:

Investor and logistics perspectives (Release No. 33-9133):

- Investors' current knowledge of IFRSs and preparedness for incorporation of IFRSs.
- Investors' education processes on changes in accounting standards and timeliness of such education.
- Extent of, logistics for, and estimated time necessary to undertake any necessary changes.

Impacts on other arrangements and requirements (Release No. 33-9134):

- Contractual arrangements (e.g., financial covenants, lease contracts, employee compensation, earn-out provisions).
- Corporate governance — stock exchange listing requirements.
- Statutory distribution restrictions and other legal standards tied to financial reporting standards.

On October 29, 2010, the SEC staff issued its first public progress report on the staff's efforts and observations to date under the work plan.

The Modified Convergence Strategy

Convergence remains a key goal of the boards, as reaffirmed by a number of public statements over the past year. The boards' November 2009 Joint Statement reaffirmed the boards' commitment to improve both IFRSs and U.S. GAAP and to converge these two accounting frameworks. The boards also committed to monthly joint meetings and agreed to publish quarterly updates on progress toward convergence. Their Joint Statement also reaffirmed the boards' Memorandum of Understanding (MoU), originally issued in 2006 and updated in 2008, and set an aggressive timetable for completing the MoU projects by June 2011.

In February 2010, the Trustees of the Financial Accounting Foundation (FAF), the FASB's oversight body, issued a statement acknowledging "the SEC's leadership regarding its consideration of global accounting standards, including its continued support for the goal of a single set of high quality globally accepted accounting standards" and noting that the FAF and the FASB "support the SEC's view that a single set of high-quality globally accepted accounting standards will benefit U.S. investors."

In June 2010, the boards announced a modified strategy for the convergence of IFRSs and U.S. GAAP. The modified plan was in response to a period of unprecedented standard-setting activity that would have resulted in the issuance of a significant number of proposals for comment in a very short period. The aggressive schedule prompted concerns by constituents about their ability to provide meaningful input on these proposals given both their number and complexity. Constituents also voiced concerns about ultimately implementing such a large number of new standards in a short period. Accordingly, the boards modified their convergence strategy to:

- Revise the MoU to give higher priority to projects that would result in significant improvements to current IFRSs and U.S. GAAP and in achieving convergence.
- Commit the boards to no more than four significant or complex EDs outstanding for comment in any one quarter, to allow for full stakeholder participation in due process.
- Issue a separate document requesting constituent input on the proposed effective date and transition methods for the projects covered under the modified convergence agenda.

The joint projects on financial instruments, revenue recognition, leases, offsetting, and fair value measurements were given priority, and the timelines were extended for (1) the projects on derecognition and financial instruments with characteristics of equity and (2) the main project on financial statement presentation.

SEC Chairman Schapiro issued a statement on the modified convergence strategy in which she outlined her support for the boards' view that increased time to allow stakeholders the ability to contribute quality feedback would be time well invested. In her statement, Ms. Schapiro noted that she did believe that the change in the boards' strategy would affect the SEC's 2011 date for determining whether to incorporate IFRSs into the U.S. capital markets for domestic issuers.

Therefore companies should continue to think about the potential effect of IFRSs, including potential differences between IFRSs and U.S. GAAP that may remain even after convergence. As U.S. practitioners know, the guidance in U.S. GAAP is often rules based, while that under IFRSs is generally more principles based. This may prove to be an interesting challenge as U.S. accounting and finance professionals reconsider the role of judgment rather than rely on guidance that is often highly prescriptive. Professional judgment will become more important by necessity, and practitioners will need to fully consider and document the facts and circumstances they relied on in reaching an accounting conclusion.

IFRSs also 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.

The comment period on the ED ended on November 20, 2009. The IASB received 155 comment letters with diverse views, both supporting and opposed to the proposed RRA standard.

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 IASB 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 IASB 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 IASB 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 IASB 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 IASB could not continue doing further analysis on the matter indefinitely and suggested that the IASB 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.

PP&E

Asset Componentization

IAS 16 requires entities to identify the significant components of an asset and then depreciate those components separately from the larger asset if they have differing patterns of benefits. This components approach means that different depreciation periods will be used for different components of a fixed asset. For example, a power plant may consist of a number of separate components with different useful lives (e.g., turbine rotor, turbine blades, boiler, electronic equipment) so that its total book value would be allocated to these separate components. These individual components would then be depreciated over their respective useful lives. Significant parts of an asset with similar useful lives and patterns of consumption may be grouped together as long as an entity can separately identify components for potential impairment or retirement purposes.

Entities that currently recognize plant assets as one overall item depreciated over a single 20- or 30-year useful life may find componentization to be a challenging process, especially if the PP&E ledger under 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:

- Group deprecation methods that are commonly used by P&U sector companies will not be permitted, so all gains and losses on retirements must be recognized in earnings.

- Assets related to planned major maintenance activities need to be identified as separate components if they meet the asset recognition requirements in IAS 16. For example, entities would need to identify the costs of estimated major maintenance or overhaul that is scheduled to be performed every five years that would typically be expensed under U.S. GAAP as a separate component upon acquisition of an asset and depreciate such costs separately rather than depreciate the entire cost of the asset over the longer useful life of the asset. When the major maintenance is performed, that component would be retired and the major maintenance cost incurred would be capitalized as a new component.

Revaluation Option

IFRSs allow entities to choose to account for PP&E under either the historical cost model (in a manner similar to the required model under U.S. GAAP) or a revaluation model. Although the revaluation model is not widely used under IFRSs, if it is elected, entities would remeasure PP&E at fair value and record changes in value directly to equity (to the extent that a net revaluation surplus remains) on a recurring basis. An entity's accounting policy must be consistent for all assets within a particular asset class. When the revalued asset is disposed of, the revaluation surplus in equity remains in equity and is not reclassified to profit or loss. However, under this model, depreciation is recorded on the revalued amount, typically resulting in a higher depreciable basis and higher depreciation expense.

Costs Eligible for Capitalization

Under IFRSs, costs that are directly attributable to bringing the asset to working condition for its intended use may be capitalized. Directly attributable costs include certain directly related employee costs, site preparation costs, delivery costs, installation costs, and professional fees. Directly attributable costs do not include administrative and other general overhead costs, which may have historically been capitalized under regulatory accounting under 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

The ED on RRAs (discussed above) proposed an additional amendment to IFRS 1 to permit regulated entities not to restate PP&E at initial adoption for amounts that would qualify for recognition as regulatory assets and allow a first-time adopter to use the carrying amount of such items as of the date of transition to IFRSs as deemed cost. At its February 2010 meeting, the IASB deliberated the summary comment letter analysis of the RRA project and the comments received on the ED on RRAs. Given the revised timing of the RRA project, the Board tentatively decided to finalize this issue and include it in the omnibus *Improvements to IFRS*, which was subsequently issued in May 2010. This exemption allows a company to report the deemed cost of the asset as if it acquired an asset with the same remaining service potential for that amount as of the date of transition to IFRSs. As with IFRS 1, there will be no accumulated depreciation or amortization reported for the asset concerned. The IASB staff further clarified that the use of this exemption does not depend on the nature of the differences between previous GAAP and IFRSs but on the fact that the asset was subject to rate regulation and that the carrying amount was determined in accordance with previous GAAP.

Asset Impairments

There are two major differences between U.S. GAAP and IFRSs on impairment:

- When assessing for impairment under U.S. GAAP, entities apply a "two-step approach." First, the carrying amount of the asset is compared with the sum of the undiscounted expected future cash flows to be generated from the asset. Second, when the carrying amount is higher, the asset is written down to its fair value. Under IFRSs, the carrying amount is compared with the asset's "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 cost to sell), and if the carrying amount is higher, the asset is written down to the recoverable amount. The ultimate effect is that impairment may be recorded earlier under IFRSs.

- Under U.S. GAAP, reversals of previous impairments are not generally permitted, although one exception is for utility companies with previously disallowed costs that are subsequently allowed by a regulator. Under IFRSs, when the indicator that led to the impairment loss no longer exists or has decreased, the previously recognized impairment charge is reversed up to the new recoverable amount. (Goodwill impairment is an exception; even under IFRSs, goodwill impairment may not be reversed.) Under IFRSs, entities will have to track asset impairments, even after the initial write-down, to determine whether the impairment should be reversed. If a change has occurred, the asset impairment may be reversed; however, the asset should not be revalued to an amount greater than the carrying amount would have been if no impairment loss had been recognized (i.e., the otherwise net carrying amount after regular depreciation expense is deducted). This will require tracking the unimpaired depreciated cost of the asset to determine the cap on the amount of any future restoration.

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

Income Taxes

A conversion to IFRSs will affect income tax accounting as a result of (1) the differences between IAS 12 and ASC 740 and (2) other pretax differences (e.g., changes to inventory or revenue recognition). Although the IASB is amending IAS 12, the FASB has indefinitely postponed its convergence efforts on income taxes. An ED on income taxes was issued on March 31, 2009. The ED (1) contained proposals for an IFRS to replace the current guidance under IAS 12 and (2) attempted to clarify aspects of IAS 12 and reduce income tax accounting differences that currently exist between IFRSs and U.S. GAAP. However, because the comments received on it were highly critical, the IASB has elected not to move forward with the ED. The IASB has indicated it will proceed with a limited-scope project to provide guidance on seven issues. Further, the IASB will consider a more comprehensive project on income taxes over a longer timeline.

The new limited-scope project on income taxes is expected to result in a new ED in the first half of 2011. The IASB has indicated that the limited-scope project will address the following areas:

- Uncertain tax positions.
- Introduction of an initial step to consider whether the recovery of an asset or the settlement of a liability will affect taxable profit.
- Recognition of a deferred tax asset in full and an offsetting valuation allowance to the extent necessary.
- Guidance on assessing the need for a valuation allowance.
- Guidance on substantive enactment.
- Allocation of current and deferred taxes within a group that files a consolidated tax return.

Also, one additional limited-scope project item on deferred tax accounting on property revaluation has been separated from the other six limited-scope project items and is the subject of a separate ED. The ED's purpose is to "provide an exception to the principle that the measurement of deferred tax liabilities and deferred tax assets should reflect the tax consequences that would follow from the manner in which the entity expects to recover or settle the carrying amount of its assets and liabilities." The ED also states that "in specified circumstances, the measurement of deferred [taxes] should reflect a rebuttable presumption that the carrying amount of the underlying asset will be recovered entirely by sale." The exception would apply to deferred taxes related to investment property measured under the fair value model in IAS 40 and property, plant, and equipment or intangibles that are revalued under IAS 16 or IAS 38.

Neither the limited scope project on income taxes nor the ED regarding RRAs addresses issues pertaining to the regulatory treatment of income tax accounting such as flowthrough accounting. These matters are addressed in U.S. GAAP on a coordinated basis in ASC 980-740.

In addition to the differences with respect to accounting for income taxes, there are many ways in which the tax function is affected outside the tax provision. Other affected areas include tax accounting methods and cash tax implications, 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.

- *Tax accounting methods* — The many pretax differences between U.S. GAAP and IFRSs are likely to result in additional book-tax differences that will need to be considered for estimated tax payments, tax return preparation, and calculation of deferred tax provisions and deferred tax assets/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 for tax purposes. If the IFRS methods are permissible and desirable for tax purposes, entities need to (1) assess whether it is necessary to obtain advance consent from the National Office of the IRS for the change in tax method of accounting and (2) determine how the cumulative effect of the change is taken into account for tax purposes. The new IFRS methods of accounting may result in a mandatory change in tax method of accounting (e.g., resulting from the LIFO conformity requirement) or may affect the timing of the recognition of an item for tax purposes (e.g., certain revenue recognition methods). Methods of accounting for which the tax method of accounting has historically followed the book method but for which a book-tax difference will exist because of conversion to IFRSs will result in incremental recordkeeping requirements and a decision about whether the tax function or another part of the entity should maintain the historical calculations needed for tax reporting purposes.

- *Tax department operations* — The many changes to the existing chart of accounts of the company may affect the tax compliance process as well as the tax provision. Entities will need to evaluate any changes to pretax accounting and systems to determine whether they affect any bridged tax systems or data requirements that the tax department may have. 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 P&U sector companies that have multinational operations, a change to IFRSs for local country statutory reporting could affect the tax liabilities owed in a jurisdictions. For example, some jurisdictions impose thin capitalization limits that limit the amount of interest expense that is deductible by an entity. Those limits are often based on debt-to-equity ratios. Change to pretax accounting is likely to affect the balance sheet and therefore affect debt-to-equity ratios and the ability to deduct interest. Other examples of areas that may be affected by a change to IFRSs on local country statutory books are transfer pricing and distributable reserves.

Derivative Instruments

The guidance under IFRSs and U.S. GAAP on accounting for financial instruments is conceptually similar; however, the requirements in some areas differ. Also, there are significant differences in detailed application. 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. Under U.S. GAAP, there are also a significant number of interpretive issues specific to energy transacting that are not specifically addressed under IFRSs, so there may be different interpretations about whether contracts qualify as derivatives.

Finally, under U.S. GAAP there are certain exemptions for legacy contracts that were executed before a particular date (such as exemptions on legacy-embedded derivatives). Since IFRS adoption is on a fully retrospective basis, P&U sector companies may have long-term arrangements that have to be reconsidered for possible embedded derivative terms.

The IASB is in the process of simplifying the accounting for financial instruments through a replacement of the current guidance under IAS 39. In November 2008, the IASB added the comprehensive financial instruments project to its agenda, which consists of three main phases:

- Phase 1: classification and measurement.
- Phase 2: impairment methodology.
- Phase 3: hedge accounting.

As part of Phase 3, the IASB has conducted a comprehensive review of the current hedge accounting requirements. The IASB has tentatively decided to replace fair value hedge accounting with an approach that presents the cumulative gain or loss on the hedged item attributable to the hedged risk as a separate line item in the balance sheet. That line item is presented within assets (or liabilities) for those reporting periods for which the hedged item is an asset (or liability). The fair value changes of the hedging instrument and the hedged item attributable to the hedged risk are taken to OCI, and any ineffectiveness is transferred immediately to profit or loss.

Among other tentative decisions, the IASB has agreed to:

- Replace the current quantitative requirements and arbitrary bright lines for measuring hedge effectiveness (e.g., 80 percent to 125 percent effectiveness) with a qualitative assessment on the basis of the objective of the effectiveness assessment that is to ensure that the hedging relationship results in an unbiased or neutral hedge (e.g., is not intentionally designed to over or under hedge) while also having a second qualification that the hedging relationship achieves more than accidental offsetting.
- Allow financial instruments managed on a contractual cash flow basis, derivatives, components of nominal amounts (i.e., proportions), and one-sided risks generally to qualify as eligible hedged items (subject to any limitations to hedge accounting that the IASB may decide as this phase of the project progresses).
- Not provide specific eligibility criteria for groups that are gross positions of hedged items of the same nature, but that have different risk characteristics, if all items affect profit or loss in the same reporting period (but rather require that when such a group of items is hedged collectively, the eligibility criteria that apply to individual items be equally applied to the group of items as a whole).
- Allow net positions consisting of a closed group of existing, nonfinancial hedged items, with different risk characteristics, that affect profit or loss in different reporting periods (e.g., a group of partially offsetting foreign currency firm commitments that settle over five periods with a forward currency forward contract used to hedge the net risk) to be eligible for hedge accounting.
- Allow a contractually specified risk component to be eligible for designation as the hedged item in a hedging relationship for hedge accounting purposes, irrespective of whether it is the component of a financial or a nonfinancial item.

- Not prohibit or require the use of certain effectiveness measurement techniques (e.g., allow for the use of percentage-based models as well as more sophisticated regression based techniques); however, changes in the method for assessing effectiveness are required if there are unexpected sources of ineffectiveness or if a rebalancing of the hedging relationship results in the previously used method no longer being capable of capturing the sources of ineffectiveness.
- Permit part of an existing item to be identified and designated as a portion (or layer) of the entire item or certain groups of items when (1) the portion is identified and documented at the inception of the hedge, (2) the designation is consistent with the risk management strategy, and (3) the fair value of any prepayment or termination option is not affected by the hedged risk.
- Prohibit equity investments designated as fair value through OCI under IFRS 9 as eligible hedged items because the changes in fair value held in OCI are never reclassified to profit and loss.

The IASB is currently undertaking an extensive outreach program with users and preparers (in particular corporate entities) to obtain input on the development of an ED on hedge accounting. The IASB plans to publish the ED, which would propose new guidance for hedge accounting, later in 2010 and a final standard by the end of the second quarter of 2011.

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

Asset Retirement Obligations

Both IFRSs and U.S. GAAP provide for the recognition of costs of dismantling and restoring a site as a liability (e.g., a "provision" under IFRSs), with an offsetting amount included in the capitalized cost of the related asset. While both accounting frameworks provide for a present value approach in measuring the liability obligation, the mechanics of each approach differs. For example, IFRSs allow an entity to incorporate provision estimates based on internally generated costs, whereas under U.S. GAAP third-party external costs must be used in the provision estimate.

Further, under U.S. GAAP, the entity's credit-adjusted risk-free rate of interest is used to discount the liability, whereas IFRSs require a rate reflecting current market conditions and risks specific to the liability. The selection of the appropriate rate to use in each case requires careful consideration. Under both accounting frameworks, after initial recognition of the ARO, the provision is reviewed as of each balance sheet date and adjusted to reflect current best estimates, which may include adjustments to the discount rate used to measure the provision. However, under IFRSs, entities use the current discount rate to remeasure the entire obligation. Under U.S. GAAP, entities only use the current discount rate to remeasure the incremental increase in the obligation; to measure the previous portion of the obligation, they use the discount rate in use at the time that portion was recorded.

IFRIC 1 specifies the accounting for changes to AROs as a result of a change in the timing or amount of cash flows and changes in discount rates (reevaluated annually under IFRSs). The accounting for these changes is significantly different depending on whether entities use the cost model or revaluation model for the related asset.

Leases

There are several key differences between IFRSs and U.S. GAAP in the area of lease accounting:

- Although the lease classification criteria are similar, IFRSs do not have the bright lines and specific criteria found under U.S. GAAP lease standards. Rather, IFRSs focus on the transfer of risks and rewards for lease classification, with only limited indicators and examples provided. Consequently, different classifications as either operating or capital/finance leases under different GAAP may be possible. In addition, the nomenclature of leases under IFRSs and U.S. GAAP differs: IFRSs have only operating and finance leases (the IFRS term for capital leases), whereas under U.S. GAAP there are operating, capital, sales-type, direct financing, and leveraged leases.

- In leases of land and buildings, IFRSs require that the land and building elements of a lease be considered separately, for purposes of lease classification, unless the land element is immaterial. However, in addition to the significance of the land element, under U.S. GAAP the land and building elements are considered as a single unit unless certain specific criteria are met. Many European companies found the application of the guidance in IFRSs on this aspect to be a particularly time-consuming process in their conversions to IFRSs, often requiring expert advice from valuation specialists to assist with these allocations.

On August 17, 2010, the boards issued an ED, *Leases*, which creates a new accounting model for both lessees and lessors and eliminates the distinction between operating and capital/finance leases, essentially requiring companies to recognize a lease asset or lease obligation on the balance sheet for all existing lease arrangements (with no grandfathering of existing arrangements). If finalized, the proposed ED would converge the FASB's and IASB's accounting for lease contracts in most significant areas (a few differences would still remain, mostly related to differences between other existing standards). The transition requirements would also be likely to require adjustment of comparative periods. Comments on the proposed ED are due by December 15, 2010, and the boards expect to issue a final standard in June 2011.

See Section 7 for additional details on convergence activities related to lease accounting.

Inventory

The cost of inventory generally includes direct expenditures of getting inventories ready for sale, including overhead and other costs attributable to the purchase or production of inventory. IAS 2 specifically requires use of either the FIFO method or the weighted-average cost method. 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 recognized 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, LIFO taxpayers will need to revert to a non-LIFO tax method of accounting for tax purposes upon adoption of IFRSs for financial reporting 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 over four years (in the case of changes that increase taxable income). When setting PGA rates, LIFO 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.

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, under IFRSs, IAS 28.27 requires that a venturer 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 upon mandating IFRSs for all U.S. issuers.

Entities generally must apply IFRSs retrospectively, recognizing all assets and liabilities in accordance with IFRSs, and derecognizing any assets and liabilities that qualified under legacy GAAP rules but do not qualify for recognition under IFRSs (with some limited exceptions noted under IFRS 1, some of which are explained below). Any differences resulting from the change in accounting policies from U.S. GAAP to IFRSs upon the initial adoption date of IFRSs are recorded directly through retained earnings. Key adoption differences or optional exemptions specific to P&U sector companies include the following:

- Fair value and other estimates as of the date of transition need to be consistent with estimates made on the same date under U.S. GAAP (after adjustment to reflect any difference in accounting policies) unless there is objective evidence that those estimates were in error.
- PP&E that previously did not require impairment loss recognition if the undiscounted cash flows exceeded carrying value may require write-down as of the date of transition if recoverable value is less than carrying value. The recoverable value of regulated PP&E will generally equal its carrying value.
- 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 on that date. IFRS 1 was also amended in 2010 to include an additional optional exemption that would permit 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 Regulatory Assets and Liabilities above for further details).
- Acquisitions and business combinations before the date of transition do not require retrospective application of IFRSs related to the assets and liabilities acquired.
- On the date of transition to IFRSs, an entity may apply the transitional provisions in IFRIC 4, which allow entities to base their determination of whether an arrangement existing on the date of transition to IFRSs contains a lease on facts and circumstances existing as of that date.

Section 4
Industry Accounting Hot Topics

Pension and Postretirement Benefits Other Than Pension Costs

Regulatory Treatment

ASC 715 has many regulatory implications. Amounts otherwise charged or credited to AOCI could or should be recorded as a regulatory asset or liability if a utility has historically recovered and currently recovers its pension expense under ASC 715-30 or its OPEB expense under ASC 715-60 in rates (the determination should be made on a plan-by-plan basis) and there is no negative evidence that the existing regulatory treatment will change.

Given the above, a P&U sector company may not need a specific regulatory order to record the regulatory asset or liability. The reasoning is that if the P&U sector company is currently recovering ASC 715 expense in rates, the AOCI amounts ultimately will be amortized to ASC 715 expense in subsequent years and thus recovered/refunded in future rates. However, if it is probable that the P&U sector company will have a curtailment/settlement as described in ASC 715-30-35 and that the related costs typically would not be recoverable in rates, a regulatory asset should not be recorded without a specific regulatory order.

If ASC 715-30 expense is on "pay-as-you-go" or some other non-ASC 715-30 method for rate purposes, but the P&U sector company has previously established support for a regulatory asset or liability, that previous support would most likely be sufficient for the P&U sector company to continue regulatory asset or liability treatment for pension AOCI amounts. If the entity does not recover ASC 715-30 expense in rates and cannot currently record a regulatory asset/liability for the difference in expense, it would need a specific regulatory order or change in rate treatment to now record regulatory assets/liabilities for the pension AOCI amounts.

As noted in the OPEB discussion below, under ASC 980-715, a regulatory asset related to ASC 715-60 costs should not be recorded if the P&U sector company's regulator continues to follow pay-as-you-go ratemaking treatment. ASC 980-715 applies only to the accounting for regulatory assets related to ASC 715-60 costs.

Accounting for OPEB Costs by Rate-Regulated Enterprises

In accordance with ASC 980-715, a regulatory asset related to ASC 715-60 costs should not be recorded in a rate-regulated enterprise's financial statements if the regulator continues to limit inclusion of OPEB costs in rates to a pay-as-you-go basis. It has been noted that the application of ASC 980-10 for financial reporting purposes requires that a rate-regulated utility's rates be designed to recover the specific utility's costs of providing the regulated service or product and that the utility's cost of providing a regulated service or product includes ASC 715-60 costs.

Further, in accordance with ASC 980-715-25-5, a regulatory asset for financial reporting purposes should be recorded for the difference between ASC 715-60 costs and OPEB costs included in rates if the utility determines that it is probable that future revenue in an amount at least equal to the deferred cost (regulatory asset) will be recovered in rates and all of the following conditions are met:

- The utility's regulator has issued a rate order, including a policy statement or a generic order applicable to utilities within the regulator's jurisdiction, that allows the deferral of ASC 715-60 costs and for the subsequent inclusion of those deferred costs in rates.
- Annual ASC 715-60 costs should be included in rates within approximately five years of the adoption of ASC 715-60. Because ASC 715-60 generally had to be adopted in 1993, the period for additional deferrals of such costs has ended.

- The combined deferral and recovery period approved by the regulator should not exceed approximately 20 years from the date of adoption of ASC 715-60. Recovery periods should end in or before 2012.

- If a regulator approves a total deferral and recovery period of more than 20 years, a regulatory asset should not be recognized for any costs not recovered by the end of the approximate 20-year period.

- The percentage increase in rates scheduled under the regulatory recovery plan for each future year should be no greater than the percentage increase in rates scheduled under the plan for each immediately preceding year (no "backloading" like in phase-in plans under ASC 980-340-25-3(d)).

In accordance with ASC 980-715-50, a utility should disclose in its financial statements:

- A "description of the regulatory treatment of [OPEB] costs."

- The "status of any pending regulatory action."

- The "amount of any [ASC] 715-60 costs deferred as a regulatory asset at the balance sheet date."

- The "period over which the deferred amounts are expected to be recovered in rates."

Defined Benefit Pension and Other Postretirement Plans

ASC 715 requires all companies that sponsor a defined benefit postretirement plan to fully recognize, as an asset or liability, the overfunded or underfunded status of that plan in their balance sheet. The funded status is measured as the difference between the fair value of the plan's assets and its benefit obligation (i.e., the projected benefit obligation for pension plans and the accumulated postretirement benefit obligation for other postretirement benefit plans).

In addition, ASC 715 also requires an entity to measure its plan assets and benefit obligations as of its year-end balance sheet date. ASC 715-30-35-62 and ASC 715-60-35-121 provide two exceptions to the measurement date provision. Those two exceptions, and the way in which the measurement date is affected, are as follows:

- When a subsidiary is the plan sponsor and has a different fiscal period from that of the parent that consolidates it, the parent should measure the subsidiary's postretirement benefit plan assets and benefit obligations as of the same date used to consolidate the subsidiary.

- When the plan is sponsored by an equity method investee and the financial statements of the equity method investee are not available timely for the investor to apply the equity method currently, the investor should measure the investee's plan assets and benefit obligations as of the same date of the investee's financial statements used to apply the equity method.

Consolidated Plans

Many utilities have consolidated pension and OPEB plans that cover employees of the parent company and several consolidated subsidiaries. These consolidated plans are often, but not always, accounted for as multiemployer plans in which pension or OPEB expense and contributions may be allocated to each subsidiary but the plan assets and obligations are not specifically attributed to any specific subsidiary. In those instances, it is appropriate for the consolidated financial statements to reflect a regulatory asset or liability for the estimated portion of the additional amounts recognized under ASC 715 in the consolidated financial statements without "pushing down" those amounts to the regulated subsidiary because the subsidiary has no separate right to any estimated allocated plan assets and no separate obligation for an estimated allocation of the consolidated plan obligation.

If the plan assets and obligations are specifically attributed to any specific subsidiaries, those subsidiaries should follow multiple-employer plan accounting in accordance with ASC 715. Accordingly, the allocated portion of the net plan assets or obligation would be reflected on the subsidiary's balance sheet as well as any related regulatory asset or balance sheet. ASC 715 multiple-employer plan disclosures would also be required in the subsidiary's financial statements.

Several utilities have recently received SEC staff comments regarding pension and postretirement plan disclosures challenging whether the utility participates in a multiemployer or a multiple-employer pension or postretirement benefit plan. Utilities should ensure that their accounting treatment and disclosures are accurate for their multiemployer or multiple-employer pension or postretirement benefit plans at both the parent and each subsidiary for which they make such disclosures. The determination of whether a company has a multiemployer plan or a multiple-employer plan often requires coordination between the accounting, legal, and human resources departments.

Recent Updates to Matters Related to Multiemployer and Multiple-Employer Plan Participation

On September 1, 2010, the FASB issued a proposed ASU, *Disclosure About an Employer's Participation in a Multiemployer Plan*. The purpose of the proposed ASU is to improve transparency by amending ASC 715-80 to significantly increase the level of quantitative and qualitative disclosures an employer would be required to make about its participation in multiemployer plans, including the effect on its cash flows. For more information about the proposed ASU, see Section 7.

Medicare Part D Regulatory Accounting Considerations

The Patient Protection and Affordable Care Act and the related Health Care and Education Reconciliation Act (the "Health Care Acts") were enacted in March 2010. While the Health Care Acts contain many provisions with accounting implications, one eliminates the deductibility of employer health care costs that are covered by federal subsidy payments. The Health Care Acts do not interrupt the federal reimbursement of the costs for coverage of retiree prescription drug expenses that are equivalent to Medicare Part D. In accordance with ASC 715-60, the estimated future costs of such coverage are reflected in the employer's liability for OPEB, and the estimated future subsidy payments are reflected as a reduction of the OPEB liability.

Under current law, the employer's OPEB costs for the equivalent Medicare Part D coverage are fully deductible for federal income tax purposes, and the subsidy payments are not included in federal taxable income. The Health Care Acts amend tax rules so that the portion of employer health care costs that are reimbursed by the federal subsidy will no longer (effective for years beginning after December 31, 2012) be deductible by the employer for federal income tax purposes.

In accordance with ASC 715-20, companies were required to recognize their full OPEB obligations in their balance sheets, with the offsetting amount recognized in AOCI. Many regulators previously, or at the time ASC 715-20 was effective, adopted rate treatment to support the probable recovery of the OPEB charge to AOCI (generally net of the tax benefit) and as a result would have established regulatory assets and liabilities associated with the recording of the OPEB obligations. To the extent that the currently nontaxable subsidy has been recognized as a reduction of OPEB expense, this tax benefit would generally have already been recognized as a reduction of income tax expense through the establishment of a related deferred tax asset.

In accordance with ASC 740, as a result of the disallowance of the future Medicare Part D Subsidy benefit under the Health Care Acts, a charge would generally be recognized in income tax expense related to continuing operations. Regulated utilities that recorded a regulatory asset for OPEB costs and a related regulatory liability for the related tax effects would record the reduction of the deferred tax asset as a reduction of the related regulatory liability for income taxes.

Regulated utilities that previously recorded this tax benefit in income tax expense would be faced with writing off the deferred tax asset and recording a tax charge in income tax expense unless they can establish that recovery of the tax charge caused by the Health Care Acts through rates is probable. In this instance, the best evidence to establish the probable recovery would generally be specific regulator guidance or recovery of similar one-time tax charges (e.g., when there have been increases in income tax rates or similar instances that caused increases in deferred income tax liabilities or decreases in deferred income tax assets).

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 ASC 805 and ASC 810 (as codified). This guidance substantially elevated the role played by fair value and dramatically changes the way companies account for business combinations and noncontrolling interests. In addition, the FASB issued ASC 820 (as codified), which provided new guidance on fair value measurements, 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 820-10-35 states that the highest and best use should be determined on the basis of potential uses that are physically possible, legally permissible, and financially feasible as of the measurement date. (Note that in June 2010, the FASB issued a proposed ASU that, among other things, clarifies the application of the highest and best use concept.) In addition, ASC 820 acknowledges that the use of an asset may be limited by restrictions to which it is subject and by agreements that restrict the asset and transfer with it upon sale (e.g., easements).

In evaluating the highest and best use of 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:
    - o Regulatory approval is required before the sale or disposition of utility assets.

- o The gain on the sale of regulated assets is required to be shared with the regulated customers.
- o 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 fair value of regulated assets in a business combination is generally viewed to be acceptable because in most instances regulation attaches to the assets (or regulation of the entity is so pervasive it effectively extends to each of the individual assets). Generally, the acquiring entity will only be allowed to recover depreciation of the original cost and earn a regulated rate of return on that property.

In certain cases, 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

Accelerated Capital Recovery

In the past, utilities and their regulators have taken various actions related to depreciation and capital recovery in the interest of accelerating the recovery of certain generation assets that may have been at risk of becoming stranded or as an alternative to adjusting rates downward if a utility was otherwise over-earning its allowed return. Such actions have included the following:

- The recording of additional depreciation provisions ratably over a number of years (e.g., $30 million per year for five years) or only under certain circumstances (e.g., if revenues exceed a certain amount or if operating earnings exceed authorized earnings levels).
- Transfers of existing depreciation reserves from one functional property classification to another (e.g., from transmission or distribution property to nuclear generation property). These reserve transfers were generally prohibited by the SEC for U.S. GAAP reporting.
- Transfer of current-period depreciation expense from one functional property classification to another (e.g., from transmission or distribution property to nuclear generation property). In this situation, total depreciation expense for the period typically remained the same. However, an additional provision was recorded in one functional classification while the depreciation provision in another functional classification was reduced by a corresponding amount. Such depreciation expense transfers were generally only permitted by the SEC for U.S. GAAP reporting as long as net depreciation expense for any class of assets was not less than zero.

Accelerated depreciation, or additional depreciation, was more prevalent in the 1990s as a means to reduce the risk of stranded costs related to nuclear and other plant assets as a result of the movement toward deregulation in the industry. The concern that assets are under-depreciated, as was the case in the 1990's, has now shifted to concern that assets are "over-depreciated," or have excess depreciation reserves. Therefore, some utilities are now trying to unwind the credit associated with these excess reserves.

"Mirror Depreciation"

If a utility has recorded accelerated or additional depreciation (as discussed above), 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 of this regulatory liability, there are no restrictions on the reversal of the excess reserves under U.S. GAAP as long as the reversal matches rate treatment.

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 so that negative cost of removal amortization could be permitted as long as the reversal matches 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 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 may conflict with the guidance in ASC 980-340 because negative depreciation is not a ratemaking method that has been routinely used by any regulator before 1982.

Accounting for Renewable Energy Certificates

The development of carbon markets worldwide has created a host of challenges for companies — and of these challenges, accounting 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, purchase contracts with third-party owners of renewable energy facilities, or 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. The discussion below focuses on 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. In many instances, 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. Contracts such as these should be evaluated under ASC 840 to determine whether they contain a lease.[1]

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) provides 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.

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

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.[2] 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.

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 nor equal to the current 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, determining whether the underlying assets 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 must be continually evaluated over their lives, REC contracts that did not previously qualify as a derivative may later meet the definition. Therefore, consideration should be given to "conditional" normal purchase/normal sale designation to understand 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, which is generally deemed 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 emissions trading schemes project to address emissions accounting, which may also include accounting for other tradable rights, such as RECs. However, both boards began discussing the project in 2007 and final guidance is not expected before 2011. 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

[2] 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.

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.

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, publication, "Carbon Accounting Challenges: Are You Ready?" available on Deloitte.com.

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

Accounting Value

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), an entity may have to allocate the purchase price to determine the appropriate cost basis. In such situations, consideration should be given to the relative fair values of the deliverables in the contract.

For RECs from internal renewable generation sources, multiple accounting models may be used to determine the carrying value. Three such models are described below.[3]

[3] The accounting value models described in this section are applicable to RECs accounted for as "inventory." ASC 350-30 notes that the "costs of internally developing, maintaining, or restoring intangible assets . . . shall be recognized as an expense when incurred." Therefore, capitalization of internally generated RECs is not typically supportable under current accounting guidance.

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 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.

Byproduct Allocation

In some circumstances, RECs may be considered a byproduct 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 byproduct. Under the byproduct method, the byproduct 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 byproduct 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 byproduct allocation methods that entities may find useful in evaluating the alternatives; this guidance can be found in 330-10-30 (Q&A 06) in Deloitte's *FASB Accounting Standards Codification Manual*.[4] Irrespective of the accounting method used to determine the original accounting basis, entities should apply the appropriate ongoing accounting and impairment models to their REC asset types. For example, REC assets should generally be expensed as they are used or sold to third parties and subject to "lower of cost 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

[4] 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.

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 the impact of shortfalls and discuss the accounting for penalties with their auditors.

Section 5
Energy Contracts, Derivative Instruments, and Hedging Activities Update

Introduction

With certain exceptions, 2010 energy prices were relatively stable compared with the volatility witnessed during the peaks of 2008 and the valleys of 2009. Early in 2010, the prospect of an economic recovery resulted in an upturn in commodity prices. However, the continued stagnant recovery through the summer and fall caused prices to drop back toward the levels experienced at the beginning of 2010. The price of natural gas saw a further drop because of a decrease in demand due to economic constraints and an increase in supply due to the continuing development of shale production.

Regulatory oversight in the energy markets has also increased. In July 2010, the Dodd-Frank Wall Street Reform and Consumer Protection Act was signed into law. The legislation regulates most derivative transactions formerly deregulated by the Commodity Futures Modernization Act of 2000. Energy entities are potentially affected primarily by the requirement to (1) clear derivatives through regulated central clearing organizations and (2) conduct mandatory trading through either regulated exchanges or swap execution facilities (subject to certain key exceptions). However, much is still unknown because many key details of the new regulations have been left to regulators to determine.

Accounting for derivatives has been the subject of recently proposed rulemaking changes, although to what degree and when these changes will occur are currently uncertain. This section summarizes current trends in the energy industry, accounting guidance currently in place, and potential future changes in the industry.

Hedge Accounting

The application of hedge accounting has remained an area of challenge and concern for industry participants throughout the P&U sector, including producers, wholesale marketing organizations, utilities, and end users. Hedge accounting has also been an area of continued focus by the SEC and regulators. There are inherent complexities associated with the application of hedge accounting to commodity activities, especially in times of depressed pricing. Commodity prices may significantly affect an entity's ability to reliably predict forecasted transactions in hedge accounting relationships.

Focus on Probability Assessment Remains Critical

One of the challenges of cash flow hedge accounting under ASC 815 is an entity's ability to demonstrate that the occurrence of a forecasted transaction that the entity intends to hedge is probable. This becomes even more challenging when the forecasted transaction is either defined as a noncontractual commitment or represents production from higher cost facilities. For example, hedging electricity output from traditional peaking facilities, which can easily be ramped up or down during periods of volatile commodity prices, presents significant challenges because many entities tend to cut the higher cost production more often when market prices are low.

As questions are raised about the probability of the forecasted transaction(s) occurring, it is important for entities to consider the guidance in ASC 815-30-40, which states:

> If it is probable that the hedged forecasted transaction will not occur either by the end of the originally specified time period or within the additional two-month period of time . . . that derivative instrument gain or loss reported in accumulated other comprehensive income shall be reclassified into earnings immediately.

Although a single instance of failing to support an assertion that the occurrence of a forecasted transaction is probable may not call into question the entity's ability to accurately forecast, a pattern of determining that the forecasted transaction will not occur may call into question the entity's use of hedge accounting for similar transactions in the future.

Some Entities Avoid Hedge Accounting

Hedge accounting offers entities immediate benefit by allowing them to exclude from current earnings any changes in the fair value of the derivatives they use to hedge their exposure to certain risks, such as commodity price fluctuations. Under a qualifying cash flow hedge relationship, for example, much of the change in fair value of the derivatives are deferred in AOCI and then taken into earnings over time as the hedged forecasted transaction affects earnings. Earning volatility is thus minimized from one period to the next. However, after evaluating the pros and cons of applying hedge accounting, some entities have, despite the benefits, considered a move away from the use of hedge accounting and instead focused on enhancing disclosures of their economic hedge program within MD&A and earnings reports. The most common complaints about hedge accounting include those about the compliance costs associated with the onerous documentation and testing requirements under the current accounting literature. Entities are also likely to be fearful of the accounting risk associated with applying hedge accounting because in prior years some entities have been forced into painful and costly restatements after a misapplication of hedge accounting.

When choosing not to pursue hedge accounting, some entities prepare enhanced disclosures as a means of calling attention to the asymmetry in their financial results (e.g., the physical asset is accounted for on a historical cost basis and the derivative instruments used to mitigate the price risk associated with those assets are recorded at fair value), and some even remove the impact of their derivative activity from GAAP earnings, as a non-GAAP adjustment, when communicating financial results. Note that entities should consider the SEC guidance on non-GAAP financial measures before determining the use of such measures.

Commodity Derivative Disclosures

Because of the increased interest in an entity's use of derivative instruments, both the SEC and FASB require specific disclosure of derivative activity, and the guidance in ASC 815-10-65-1 was adopted by most entities in 2009. The guidance provided for enhanced transparency about an entity's use of derivative instruments, including the nature of their use, the accounting model for derivative instruments, and increased disclosure of their impact on the financial statements.

Some common issues in the energy industry related to derivative disclosure requirements in ASC 815-10-50-1 through 50-4 are discussed below.

Disclosure Requirement	Implementation Considerations
Volume disclosures (ASC 815-10-50-1B)	Practice is diverse regarding both the level of disaggregation (by commodity, by activity, or no disaggregation) and whether the volumes should be shown gross or net. Gross volume disclosure includes the sum of all short and long positions on an absolute value basis or separate disclosure of short and long positions. Net volume disclosures include the net open position after offsetting long and short positions (some entities disclose this information on a delivery-month basis whereby short and long positions are netted by delivery month and then the sum of the absolute monthly position is presented; others offset the entire position throughout delivery months). There is no prescribed approach; however, entities should disclose whether the amounts are presented on a gross or net basis.

Disclosure Requirement	Implementation Considerations
Balance sheet table (ASC 815-10-50-4B)	Practice is diverse in the calculation of derivative assets and liabilities disclosed in the balance sheet table. Entities appear to use two primary approaches: • Amounts in the balance sheet table represent gross assets and liabilities and are mapped according to where on the balance sheet they are presented, after the impact of netting under ASC 815-10-45 is taken into account. • Amounts in the balance sheet table represent gross assets and liabilities classified into current and noncurrent categories; a "reconciling" column is included on the impact of netting under ASC 815-10-45 to reconcile to the balance sheet (reconciling column includes both fair value and collateral netting).
Derivatives designated as hedges — effective portion recorded in OCI and amount reclassified from OCI to earnings (ASC 815-10-50-4C)	Calculation of OCI and amounts reclassified into earnings should include intraperiod changes in market prices and intraquarter transactions. Some entities use the beginning of the period balance to determine amounts reclassified from OCI into earnings; however, this amount should be based on actual realized gains and losses. This method results in the improper exclusion of changes in prices that occur within the period associated with settled transactions and also excludes hedges that were executed and settled within the period. As a practical expedient, the settlement values may be estimated on the basis of the fair value of contracts as of the end of the month before settlement if intramonth changes in prices are deemed insignificant.
Derivatives not designated as hedges — realized gains and losses (ASC 815-10-50-4C)	Calculation of realized gains and losses on physical and financial contracts should be performed in the same manner. Physical contracts settle at the notional value (contract price multiplied by the notional volume); however, the cash settlement value of physical contracts does not represent realized gains or losses related to such contracts. Realized value for physical contracts, like financially settled contracts, should be calculated on the basis of the difference between the fixed and floating prices over the notional volume. As a practical expedient, the settlement values may be estimated on the basis of the fair value of contracts as of the end of the month before settlement if intramonth changes in prices are deemed insignificant.
Derivatives not designated as hedges — regulatory deferral (ASC 815-10-50-4C)	Practice is diverse in the determination of unrealized and realized gains and losses that are deferred in regulatory assets or regulatory liabilities. Some entities present unrealized and realized gains and losses that are deferred in regulatory assets or liabilities as a separate line in the income statement table; others disclose such amounts as a footnote to the income statement table; still others present such amounts in a separate table. Most entities present only unrealized gains and losses that were deferred into regulatory assets or liabilities; however, some also disclose the release of realized gains and losses from regulatory assets and liabilities into earnings. There is no prescribed or preferred approach that entities should consider, as long as the portion of unrealized and realized gains and losses that is deferred into regulatory assets and liabilities is clearly and adequately disclosed.

Disclosure Requirement	Implementation Considerations
Credit-risk-related contingent features — net liability calculation in determining additional collateral requirements if credit contingent features are triggered (ASC 815-10-50-4H)	Practice is diverse on whether the net liability amount used in the determination of additional collateral requirements, if credit contingent features are triggered, should include only derivatives in a net liability position on the balance sheet or include all transactions executed under a master netting agreement regardless of whether the contracts meet the definition of a derivative (e.g., they include transactions for which the NPNS scope exception has been elected). Some entities include only those contracts that are accounted for as derivatives on the balance sheet. Others include all contracts (whether accounted for as a derivative or not) that are subject to a master netting arrangement. On the basis of discussions with the FASB staff, either approach is acceptable, and entities should provide adequate disclosure about which method they are employing.
Credit-risk-related contingent features — Identification of features related to credit (ASC 815-10-50-4H)	Identification of credit-risk-related contingent features is difficult, and there are complexities associated with whether some contingent features are truly related to credit risk. For example, when does an event of default qualify as a credit contingent feature, if ever? A detailed discussion of various types of credit-risk-related contingent features and examples follows this table. In addition, most entities do not have a robust inventory of credit-risk-related features in their portfolio of contracts; many entities therefore had to adopt new processes and controls to ensure that the appropriate level of contract detail was captured in their systems.

Features That Are Considered Credit-Risk-Related Contingent Features

Upon implementing the guidance in ASC 815-10-65-1, entities were also required to disclose the potential risk associated with certain credit-contingent features within contractual arrangements. An entity should consider the following guidelines, developed on the basis of discussions with the FASB staff, when assessing whether individual features represent credit-risk-related contingent features that must be disclosed under ASC 815-10-50-4H.

- *Disclosure is not limited to features that trigger cash payments* — Although ASC 815-10-50-4H generally focuses on liquidity exposure, it encompasses any feature that would require the use of an entity's "assets."

- *The feature could reside in a contract or governing arrangement (e.g., MNA)* — Many derivatives are executed under standard legal arrangements (e.g., ISDAs) that establish key terms and conditions and often provide for netting among the counterparties in certain situations. In such cases, the "master" arrangement typically serves as an umbrella governing each executed derivative and it is therefore necessary to look to the master arrangement for contingent features.

- *The feature must be objective* — More specifically, the feature must cite one or more specific contingent events and describe what the specific payment terms would be if the contingent event were to occur. For example, a feature requiring an entity to post a certain dollar amount or percent of contract value with the counterparty if the entity's credit rating drops below investment grade would be considered an objective feature. Material adverse-change clauses may or may not be objective. "General adequate assurance" clauses, which give each party in an arrangement the right to seek additional collateral as it deems necessary (but not on the basis of a specified credit event) are not considered objective, although entities are encouraged to provide supplemental disclosure about the existence of these types of provisions.

- *The feature should relate directly to credit events or measures of creditworthiness* — Collateral requirements based solely on market indices (e.g., interest rates, commodity prices) or based solely on the fair value of a derivative or a portfolio would generally not be considered credit-risk-related contingent features because they are not driven by discrete credit events. Likewise, although many operational events affect credit, contingencies driven by operations generally are not considered credit-risk-related contingent features. Accordingly, events such as a decline in revenues or a loss of a major customer would not be considered credit-risk-related contingent features that must be disclosed under ASC 815-10-50-4H. However, contingencies based on an entity's failure to maintain specified liquidity ratios (e.g., current ratio or quick ratio) or financial leverage ratios (e.g., debt ratio or debt-to-equity ratio) would generally be considered credit-risk-related contingent features.

- *Default provisions do not constitute credit-risk-related contingent features* — Default provisions are triggered by an entity's failure to perform under a particular contract. Contingent features, on the other hand, generally relate to factors or events external to the contract (e.g., a decline in a credit rating or a failure to maintain a minimum current ratio) and require incremental performance (e.g., posting of collateral) by one party or the other. Although some default events are ostensibly credit-driven, it is not necessary to identify credit-specific default provisions (e.g., payment delinquency or deficiency) and treat those events as credit-risk-related contingent features.

- *Cross-default provisions require special consideration* — In contrast to the default provisions discussed above, cross-default provisions relate to factors external to an entity's performance under the contract in question; accordingly, an entity must carefully consider the terms and conditions of such provisions to determine whether they are within the scope of ASC 815-10-50-4H. In some circumstances, a cross-default provision may constitute a credit-risk-related contingent feature (e.g., when a failure to make a required interest or principal payment on a debt instrument triggers a collateral call or early settlement of a derivative liability). In this case, the failure to make a required interest or principal payment could be viewed as a credit event. In contrast, a cross-default provision based on a failure to deliver goods under a commodity sales contract could be due to factors other than credit.

- *Bankruptcy and liquidation events do not constitute credit-risk-related contingent features* — If payment is required only upon bankruptcy or final liquidation of the entity, those features would not be considered credit-risk-related contingent features that must be disclosed under ASC 815-10-50-4H.

Multiple-Element Arrangements and the P&U Sector

The nature of the physical electricity markets, transmission systems, and distribution networks is such that the production and delivery of energy involves multiple products or services in addition to just the delivery of "physical" energy. Those products may include capacity credits, various ancillary services, emissions allowances, and renewable energy credits. Although the electricity component is typically the most predominant product in the contract, entities frequently execute contracts that combine energy with one or more of these additional products or services. The accounting for the bundled contracts is complex and may require an entity to consider whether the various elements in a 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 being delivered, or (3) a nonderivative or executory contract that contains multiple products or services being delivered.

A contract that contains multiple elements requires careful analysis and should include consideration of the literature on derivatives, lease accounting, and revenue recognition:

- *Derivative 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 reached in the first step, there may be additional complexities in the determination of the appropriate fair value to assign to the identified derivative instruments. For example, to the extent that it is determined the contract meets the definition of a derivative in its entirety, 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 contract is more akin to a host contract with an embedded derivative, then the embedded derivative guidance in ASC 815 should be followed, which may result in the entity's only valuing the embedded derivative or potentially valuing the entire contract to the extent that the embedded derivative cannot be separated from the host contract.

- *Lease accounting* — The lease accounting literature related to multiple-element type arrangements can also present difficulty. A primary issue in the assessment of a contract under the leasing literature is the identification of what the output of the referenced facility is in the context of identifying when a lease is present 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. Also, a multiple element contract that may have been executed at a bundled price can present problems in the determination of how to allocate the price to the lease and nonlease elements, if present. Finally, a contract that is determined to contain a lease may contain other elements that require further accounting analysis (e.g., the existence of a derivative or a variable interest).

- *Executory contract* — For contracts that are neither derivatives nor leases, multiple-element arrangements also present difficulty in the determination of the proper revenue recognition for the contract. To the extent that the contract contains multiple delivery obligations occurring in different periods, it is important for entities to consider whether the seller's obligations have been fulfilled for each of the elements in the determination of 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 as well as the guidance in pre-codified EITF 00-21, EITF 08-1, and EITF 91-6.

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

Future Changes

ERCOT Move to Nodal Pricing

In September 2003, as part of Project 26376, the Public Utility Commission of Texas ordered ERCOT to develop a nodal wholesale market design. This transition from a current zonal pricing market to a nodal pricing market is expected to occur in December 2010. The expected benefits of the transition are to improve the transparency of pricing to encourage additional generation and transmission investment, increase dispatch efficiency, and improve the assignment of congestion costs.

Historically, ERCOT prices were based upon the respective price at each of the four ERCOT zones. Prospectively, pricing will be based on locational marginal pricing at hundreds of individual nodal points. Thus, instead of power settlements being based on four broad pricing indices, power settlements will be based on hundreds of individual nodal indices. As a result, congestion will no longer be between zones, but will be between nodes. In anticipation of this, ERCOT will issue and auction CRRs. CRRs are financial instruments designed to be an economic hedge against congestion costs and are expected to be similar to FTR in PJM or MISO.

Hedge Accounting

Given the uncertainty of timing, pricing and how the nodal market will develop after the transition has occurred, determining the forward market price at individual nodal locations may prove to be difficult. On the basis of experience gained in other markets that moved from a zonal price to a nodal price, we anticipate one or more "trading hubs" will develop (i.e., PJM-West within PJM) against which most derivative contracts are expected to settle; however, the risks that an entity is attempting to hedge are typically at specific nodes. This change will affect hedge accounting in several ways:

- *Dedesignation/Redesignation* — Depending upon how the original hedge relationship was documented, the hedge relationship may not exist under the new market structure. This would cause the original hedge relationship to be dedesignated and a new hedge relationship designated on the basis of the pricing exposure under the new market structure. Most entities will want to redesignate existing transactions, which will have a fair value other than zero on the date of designation. The impact of a starting fair value other than zero will need to be considered in the assessment and measurement of the hedge relationship.

- *Ineffectiveness* — If the hedge relationship does continue to exist under the new market structure, the mismatch in basis created from the nodal structure will create ineffectiveness in a hedging relationship that may not have existed before the move to a nodal pricing model.

- *Assessment* — This move will also affect how entities assess the effectiveness of their hedges. ASC 815-20-25-75 requires that to qualify for hedge accounting, the hedging relationship, both at inception of the hedge and on an ongoing basis, be highly effective in offsetting changes in fair value or changes in cash flows attributable to the risk being hedged. This requirement is typically met by the use of either a regression analysis or some sort of ratio comparison.

  A regression analysis may require either historical settled pricing information or forward pricing estimates for not only the derivative instrument but also the hedged location. Similarly, a ratio comparison will require a forward pricing estimate for both the derivative instrument and the risk being hedged. Because the transition to nodal pricing has not yet occurred, there is no historical pricing information available for entities to use to determine the expected relationship between a zone or hub and a nodal price. In addition there is very little if any transacting in the market for the many different nodes that will exist upon transition to a nodal market and therefore forward price data does not exist either. Consequently, entities are finding it challenging to develop quantitative evidence to support the assertion that a hedge is expected to be highly effective. Entities should carefully consider what inputs and modeling assumptions should be evaluated when making this assessment. For additional information about the impact of this market change on hedge accounting assessments, please contact your Deloitte team.

Congestion Revenue Rights

A congestion revenue right is a financial instrument defined by a megawatt amount, settlement point of injection, and settlement point of withdrawal. Conceptually, a CRR owner gets paid or pays the LMP difference between the CRR injection and withdrawal settlement points for each CRR megawatt owned. In other markets, similar type instruments have been determined to meet the definition of a derivative and thus have been required to be recorded at fair value with the offset affecting the income statement (or deferred as a rate regulated asset or liability as applicable). Entities should be aware of the financial nature of CRRs and their potential impact on the financial statements.

Financial Reform Bill Impact

The Dodd-Frank Wall Street Reform and Consumer Protection Act became law on July 21, 2010. As a response to the financial crisis, it seeks to increase accountability and transparency in financial markets. Much of this legislation is aimed at Wall Street. New "OTC derivative regulation by the CFTC" will affect energy entities.

A broad energy industry coalition was active in lobbying Congress to include energy entities in the commercial end-user exemption. The degree to which energy transactions are included in this end-user exemption and the overall impact of this new legislation most likely will not be known until the CFTC completes its drafting of regulations, a process that could take 12 months or more.

Of key importance to entities will be how the CFTC defines an end-user and hedging activities. Congress has provided guidance on how it hopes regulators will interpret the legislation. A June 30 letter by Sens. Christopher Dodd, D-Conn., and Blanche Lincoln, D-Ark., sought to clarify the rationale for exempting gas and electric utilities looking to hedge from the clearing, margin, and capital requirements of the bill. The letter stated, in part:

> For example, the major swap participant and swap dealer definitions are not intended to include an electric or gas utility that purchases commodities that are used either as a source of fuel to produce electricity or to supply gas to retail customers and that uses swaps to hedge or manage the commercial risk associated by its business.

CFTC Chairman Gary Gensler has also gone on record with his stance on the end-user exemption, stating, "While it is clear that the bill will include exemptions for commercial end-users of derivatives, that exemption should be narrow and well-defined."

There is significant ambiguity about which entities will qualify as commercial end-users because energy marketing and trading organizations often participate in a variety of asset-backed transacting activities to optimize the value of their portfolios. Once regulations are established, entities will need to determine which activities they are confident will qualify as bona fide hedges if they do not want to risk their end-user status. At this key juncture in the rulemaking process, entities should seek opportunities to confirm the CFTC's understanding of their business activities so that regulations can be properly crafted. Potential opportunities include:

- Participating in relevant rulemaking with the CFTC.

- Consider the strategic and tactical implications of potential rule changes to managing commodity price risk.
- Assess the capabilities of supporting infrastructure to manage upcoming regulatory requirements.

Potential outcomes of the upcoming regulations may include:

- Tighter cash flows as a result of requirement that current OTC derivatives be cleared through regulated exchanges.
- Uncertain dynamics in market liquidity as a result of additional transaction costs and standardization of products.
- Additional transparency resulting in tighter bid-ask spreads.
- Expanded internal and external compliance oversight and reporting requirements.
- Potential for migration of liquidity to international markets subject to less regulation.

Section 6
Fair Value Measurements

Introduction

Although most entities adopted the provisions of ASC 820 for calendar year 2008, the continued volatility and depressed commodity pricing in the marketplace during 2010 kept fair value accounting and disclosures at the forefront of the accounting landscape. This was particularly true for fair value measurements for transactions in markets in which the volume and level of activity have significantly decreased. The discussion below addresses future accounting guidance affecting the requirements ASC 820 and of potential valuation concerns affecting the energy industry.

Recently Issued Guidance

In January 2010, the FASB issued ASU 2010-06, which amends ASC 820. Certain provisions of ASU 2010-06 were effective for interim and annual periods beginning after December 15, 2009; thus, for calendar-year-end entities subject to quarterly reporting requirements, the provisions were effective for the interim period ending March 31, 2010. Accordingly, certain implementation questions about ASU 2010-06 have arisen, as discussed below.

Transfers Between Levels — New Requirements for Timing of Transfer Recognition

Before the effective date of ASU 2010-06, ASC 820 only required disclosures about transfers into and out of Level 3 for recurring fair value measurements as part of the Level 3 reconciliation of beginning and ending balances. The ASU 2010-06 amendments expand these disclosure requirements to include all three levels of the fair value hierarchy. Specifically, a reporting entity is now required to disclose separately the amounts of, and reasons for, significant transfers (1) between Level 1 and Level 2 of the fair value hierarchy and (2) into and out of Level 3 of the fair value hierarchy for the reconciliation of Level 3 measurements. In addition, an entity must disclose and follow a consistent policy for determining **when** transfers between levels are recognized. According to ASC 820-10-50-2:

> A reporting entity shall disclose and consistently follow its policy for determining when transfers between levels are recognized. The policy about the timing of recognizing transfers **shall be the same** for transfers into the levels as that for transfers out of the levels. Examples of policies . . . are as follows:
>
> 1. The actual date of the event or change in circumstances that caused the transfer
> 2. The beginning of the reporting period
> 3. The ending of the reporting period [Emphasis added]

Further, a reporting entity that changes its policy for the timing of transfers into and out of Level 3 as a result of ASU 2010-06 should follow the ASU's transition provision that requires prospective application in the period of initial adoption.

Level of Disaggregation of Derivative Contracts for Fair Value Measurement Disclosures — ASC 815 Contract Type May Differ From Class

ASU 2010-06 amended ASC 820 concerning the required level of disaggregation for derivative contracts. The ASU states:

> The reporting entity shall determine appropriate classes of assets and liabilities on the basis of guidance in the following paragraph. . . . A reporting entity shall determine the appropriate classes for those disclosures on the basis of the nature and risks of the assets and liabilities and their classification in the fair value hierarchy (that is, Levels 1, 2, and 3). In determining the appropriate classes for fair value

> measurement disclosures, the reporting entity shall consider the level of disaggregated information required for specific assets and liabilities under other Topics. For example, under Topic 815, disclosures about derivative instruments are presented separately by type of contract such as interest rate contracts, foreign exchange contracts, equity contracts, commodity contracts, and credit contracts.

Consequently, implementation issues have arisen concerning how the term "class," as discussed in ASU 2010-06, compares with the term "type of contract" used for the ASC 815 tabular disclosures.

In supporting its judgments about the determination of class for its derivative contracts, an entity should consider the type of derivative contracts it holds. However, class is based on the nature and risks of the derivatives and their classification in the hierarchy and is often at a greater level of disaggregation than the reporting entity's line items in the statement of financial position. Therefore, in determining the nature and risks of its derivative contracts, an entity should consider the following factors: the valuation techniques and inputs used to determine fair value, the classification in the fair value hierarchy, and the level of disaggregation in the statement of financial position. An entity may also consider the level of disaggregation it uses for other ASC 815 disclosures (e.g., qualitative and volume), which may vary from the level of disaggregation it uses for the ASC 815 tabular disclosures.

Disclosures About Fair Value Measurement Inputs and Valuation Techniques — Quantitative Information About Inputs

ASU 2010-06 requires a reporting entity to provide disclosures about the valuation techniques and inputs used to measure fair value for both recurring and nonrecurring fair value measurements in Level 2 or Level 3 of the fair value hierarchy and for each class of assets and liabilities. It states:

> For fair value measurements using significant other observable inputs (Level 2) and significant unobservable inputs (Level 3), a description of the valuation technique (or multiple valuation techniques) used, such as the market approach, income approach, or the cost approach, and the inputs used in determining the fair values of each class of assets or liabilities. . . . Examples of disclosures that the reporting entity may present to comply with the input disclosure . . . include the following:
>
> a. Quantitative information about the inputs, for example, for certain debt securities or derivatives, information such as, but not limited to, prepayment rates, rates of estimated credit losses, interest rates (for example, LIBOR swap rate) or discount rates, and volatilities.

From the above guidance and informal feedback received from the FASB staff, one can conclude that an entity is not required to disclose quantitative information about inputs. However, in many instances, an entity may conclude that such information is appropriate. This determination will be based on the entity's evaluation of what types of input disclosures enable financial statement users to assess the entity's valuation techniques and inputs. In preparing its disclosures about inputs, an entity should follow the above-cited guidance. The discussion of inputs is expected to vary by class of assets or liabilities, level in the fair value hierarchy, and the valuation technique(s) used. Likewise, there should be some degree of consistency between the items discussed in the narrative about inputs and valuation techniques and the class determination. For example, disclosure about inputs specific to a certain commodity type (e.g., average tenor and geographic concentration for natural gas positions) may suggest that the commodity type should represent a class of its own.

Future Changes

ERCOT Moving to Nodal Pricing

As discussed in Section 5, ERCOT is transitioning to a nodal pricing structure in December 2010. In addition to the potential hedge accounting implications discussed in Section 5, this transformation will also affect the fair value measurements of certain derivative contracts:

- *Wholesale market pricing activity* — On the basis of other nodal markets, it is expected that OTC physical contracts primarily will be priced at major trading locations, which are expected to be near high usage or generation areas. However, the identification of these locations within the market is still unknown, and determining an appropriate forward price may therefore be difficult.

- *Resource pricing versus load pricing* — The prices received by generators are expected to be based on specific nodes, while the pricing for end-users is expected to be based on zonal pricing. Thus, in addition to developing a forward price for each location, entities must be aware of the expected pricing of the individual derivative contract because the type of contract will affect the appropriate price estimate to use.

- *CRR valuations* — CRR auctions are expected to occur monthly and annually. The amount of market participation of these auctions and the resulting liquidity of individual CRRs is still unknown. In addition, not all CRRs may be traded in every auction. Entities should understand the impact of market liquidity and an entity's valuation method to determine the required fair value hierarchy disclosure classification. Preparers are also reminded that while auction results may indicate fair value on the auction date, it is necessary to consider other factors in assessing fair value, particularly when the auction results are stale relative to the reporting date.

- *Structured contract valuation* — Because of the business model changes noted in Section 5, the valuation of structured contracts that contain risks other than just the price of power will need to be reassessed. For example, entities will need to understand how the pricing for congestion, capacity, and ancillary services will be affected by this change. In addition, many of the pricing points specified in structured contracts currently have no observable price quotes in the market, which may affect the categorization of the contract in the fair value hierarchy required for disclosure purposes because of the significance of Level 3 inputs that may exist. The level in the fair value hierarchy within which the fair value measurement in its entirety falls is based on the lowest level input that is significant to the overall measurement.

Proposed Fair Value Measurement and Disclosure Update

On June 29, 2010, the FASB issued a proposed ASU, *Amendments for Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs*. The proposed ASU is the result of a joint project between the FASB and IASB (the "boards") to develop a single, converged fair value framework. Notable provisions of the proposed ASU include the following:

- *Highest-and-best-use concepts* — The proposed ASU amends the guidance on the highest-and-best-use and valuation-premise concepts by clarifying that they only apply to measuring the fair value of nonfinancial assets. The boards concluded that financial assets and liabilities "do not have alternative uses." Under the proposal, the highest and best use of a nonfinancial asset "is determined from the perspective of market participants, even if the reporting entity intends a different use. However, a reporting entity's current use of an asset is presumed to be its highest and best use unless market or other factors suggest that a different use by market participants would maximize the value of the asset." In determining the highest and best use, an entity must still contemplate whether the use of the asset is physically possible, legally permissible, and financially feasible.

- *Instruments managed within a portfolio* — The proposed ASU provides an exception to fair value measurement when a reporting entity holds a group of financial assets and financial liabilities that have offsetting positions in market risks or counterparty credit risk that are managed on the basis of its net exposure to either of those risks. That is, when an entity has a portfolio in which the market risks (e.g., interest rate risk, currency risk, other price risks) being offset are substantially the same, "the reporting entity shall apply the price within the bid-ask spread that is most representative of fair value in the circumstances to the reporting entity's net exposure to those market risks." In addition, when there is a legally enforceable right to offset one or more financial assets and financial liabilities with a counterparty (e.g., master netting agreement), "the reporting entity shall include the effect of the reporting entity's net exposure to the credit risk of that counterparty in the fair value measurement." The proposed ASU further indicates:

> If the reporting entity has a net short position (that is, the reporting entity owes the counter-party), the reporting entity shall apply such an adjustment on the basis of its own credit risk. If the reporting entity has a net long position (that is, the counterparty owes the reporting entity), the reporting entity shall apply an adjustment on the basis of the counterparty's credit risk.

The proposal outlines the following criteria an entity must meet to use the exception:

- 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 (e.g., the reporting entity's board of directors or chief executive officer).
- Manages the net exposure to a particular market risk (or risks) or to the credit risk of a particular counterparty in a consistent manner from period to period.
- Is required to or has elected to measure the financial assets and financial liabilities at fair value in the statement of financial position as of each reporting date.

The ASU's proposed amendments are intended to reduce the current diversity in how entities interpret the fair value measurement guidance on financial instruments managed on a portfolio basis. The FASB indicated that the change in guidance is meant to reflect current practice and that it believes the "proposed amendments would not change how financial assets and financial liabilities that are managed on the basis of a reporting entity's net risk exposure are measured in practice." However, the FASB acknowledged that current practice could be affected for entities that tend to apply the in-use valuation premise more broadly (e.g., for financial assets that do not have offsetting positions in market risks or counterparty credit risk). For these entities, a different fair value measurement conclusion may result when the proposed amendments are applied.

- *Sensitivity disclosures* —The proposed ASU requires entities to disclose information about measurement uncertainty in the form of a sensitivity analysis for recurring fair value measurements categorized in Level 3 of the fair value hierarchy unless another Codification topic specifies that such disclosure is not required (e.g., investments in unquoted equity instruments are not included in the scope of the disclosure requirement under the accounting for financial instruments project). Specifically, the amendment to ASC 820-10-50-2(f) states that an entity would disclose the following:

> A measurement uncertainty analysis for fair value measurements categorized within Level 3 of the fair value hierarchy. If changing one or more of the unobservable inputs used in a fair value measurement to a different amount that could have reasonably been used in the circumstances would have resulted in a significantly higher or lower fair value measurement, a reporting entity shall disclose the effect of using those different amounts and how it calculated that effect. When preparing a measurement uncertainty analysis, a reporting entity shall not take into account unobservable inputs that are associated with remote scenarios. A reporting entity shall take into account the effect of correlation between unobservable inputs if that correlation is relevant when estimating the effect on the fair value measurement of using those different amounts. For that purpose, significance shall be judged with respect to earnings (or changes in net assets) and total assets or total liabilities, or, when changes in fair value are recognized in other comprehensive income, with respect to total equity.

The boards decided to require sensitivity disclosure in response to comments received from IFRS financial statement users and from comments received in response to the ED that led to ASU 2010-06. IFRSs users indicated to the boards that the "measurement uncertainty analysis disclosure required by IFRS 7 provides useful information that helps them assess the subjectivity of a reporting entity's fair value measurements categorized within Level 3 of the fair value hierarchy." However, users also thought the IFRS 7 requirements could be enhanced to include the effect of correlation between unobservable inputs because such information would help them "to assess the extent to which using a different unobservable input can affect a fair value measurement." The boards agreed that an uncertainty analysis would be more meaningful if, when relevant, the correlation between unobservable inputs is taken into account.

For entities that do not currently provide the sensitivity analysis or have it readily available, preparing the proposed disclosures may prove challenging. Entities may need to consider (1) upgrading their information technology systems and existing valuation models to comply with the proposed disclosure requirements and (2) the effect of those disclosure requirements on their internal controls over financial reporting. For financial instruments that an entity may be required to measure at fair value as a result of the proposed amendments to other Codification topics, the entity would need to assess whether its internal personnel are sufficiently well versed in fair value measurements to comply with the additional fair value requirements.

Section 7
Accounting Standards Codification Update

Variable Interest Entities

Statement 167 (ASU 2009-17), codified in ASC 810, was effective for most entities[1] for all interim and annual reporting periods beginning after November 15, 2009. Accordingly, this standard became effective for calendar-year reporting entities on January 1, 2010, and many public companies reported the impact of adopting this standard in their first quarter 2010 Form 10-Qs.

The guidance in ASU 2009-17 significantly changed the consolidation model previously followed under Interpretation 46(R) and required companies to carefully reconsider previous conclusions about the consolidation of VIEs, including conclusions about (1) whether an entity is a VIE, (2) whether the company is the primary beneficiary of the VIE, and (3) the nature and extent of disclosures related to involvements with VIEs.

The guidance in ASU 2009-17 significantly changed the approach for determining the primary beneficiary of a VIE. Under the previous consolidation model, each holder of a VI was often required to perform a quantitative analysis to determine which VI holder in a VIE absorbs a majority of the VIE's expected losses or receives a majority of its residual returns and was therefore considered the primary beneficiary. Note that only a holder of a VI can consolidate a VIE, so in the application of the consolidation guidance, the first step is the determination of whether an interest in an entity is a VI. Generally speaking, the determination of a VI under the new guidance is consistent with such determination under the old guidance. See Deloitte's October 20, 2010, *Heads Up* on Statement 167 for considerations in the determination of whether an entity is a VIE.

Under ASU 2009-17, the evaluation of whether a VI holder is the primary beneficiary of a VIE is based on a qualitative assessment. A VI holder must determine qualitatively whether it has (1) the power to direct the activities of the VIE that most significantly affect the VIE's economic performance and (2) the obligation to absorb losses of the VIE or the right to receive benefits from the VIE that could potentially be significant to the VIE. If a VI holder has both of these characteristics, it is considered to be the primary beneficiary and must consolidate the VIE. If the VI holder determines it has only one, or neither, of these characteristics, it is not considered to be the primary beneficiary and would not consolidate the VIE.

In the performance of the qualitative analysis of the role of power in the primary beneficiary analysis under ASU 2009-17, the risks and rewards considered under the previous model remain relevant, but have become secondary to the control over activities that drive the VIE's variability. In making the primary beneficiary determination, VI holders must determine and evaluate those activities that most significantly affect the VIE's economic performance.

Economic performance is a broad concept that extends well beyond those activities that have a direct impact on the net income of the VIE. Instead, the consideration of economic performance should be based on the activities that affect the risks in the VIE that are created and passed along to the VI holders. Too narrow a focus on economic performance can lead to incorrect conclusions about the consolidation of a VIE. After identifying the risks that are expected to have the most significant impact on the VIE's

[1] In February 2010, the FASB issued ASU 2010-10, which amended certain provisions of the VIE model in ASC 810-10. The ASU deferred the effective date of Statement 167 for a reporting entity's interest in certain entities and certain money market mutual funds. The ASU also deferred the application of Statement 167 for a reporting entity's interest in an entity (1) that has all the attributes of an investment company or (2) for which it is industry practice to apply measurement principles for financial reporting purposes that are consistent with those followed by investment companies. The deferral did not apply in situations in which a reporting entity has the explicit or implicit obligation to fund losses of an entity that could potentially be significant to the entity. The deferral also did not apply to interests in securitization entities, asset-backed financing entities, or entities formerly considered QSPEs. In addition, the deferral applied to a reporting entity's interest in an entity that is required to comply with or operate in accordance with requirements similar to those in Rule 2a-7 of the Investment Company Act of 1940 for registered money market funds. These entities were subject to the deferral even if the money market fund manager has an explicit or implicit obligation to fund losses of the entity.

performance, the VI holder needs to carefully consider the decision-making activities related to those risks. In the case of a single-plant generation facility, these decisions and related activities may include, for example, decisions about when to operate the facility; how to operate the facility; purchases of fuel, materials and supplies; selling excess output; maintenance; hiring and firing of employees; and the disposition of the plant at the end of its useful life.

When assessing control or the "power to direct," the VI holder should consider the remaining life of the VIE or the remaining term of the company's involvement with the VIE (including end-of-term options). For example, in the case of a single-plant entity currently in operation, the assessment of the power to direct the activities that are most significant to a VIE's economic performance involves consideration of the power during the remaining life of the involvement with the VIE.[2] As discussed below, ASU 2009-17 requires a continual assessment of the VIE's primary beneficiary; consideration of the remaining useful life is therefore important because the rights may change or the VI holder's power relative to other VI holders' power may change over time. Such changes could lead to different conclusions about consolidation of the VIE.

ASU 2009-17 also requires, prospectively upon adoption, separate presentation on the face of the balance sheet for (1) assets of a VIE that can only be used to settle obligations of the VIE and (2) liabilities of the consolidated VIE for which creditors do not have recourse to the general credit of the primary beneficiary. Companies with a variable interest in a VIE must disclose any circumstances that require the entity to provide future support to the VIE and any significant judgments and assumptions they used in the primary beneficiary analysis. Furthermore, ASU 2009-17 requires (1) description of any changes in conclusions regarding consolidation of the VIE and any changes to commitments to future funding of VIEs and (2) additional disclosures for companies with variable interests in a VIE and for companies that are the primary beneficiary of a VIE.

Implementation Challenges

As companies implemented the guidance in ASU 2009-17, many discovered that the process was more than just an accounting exercise. Such companies initially struggled with the qualitative analysis and wanted to apply thresholds or bright lines to their consolidation analysis and conclusions. Nowhere was this more evident than in the debates that ensued over the terms "significant" and "more than insignificant" as those terms are used in ASC 810. As practice and guidance developed, companies began focusing more on the qualitative aspects of the economic involvements rather than solely on the quantitative measures that were historically commonly used to determine significance. In fact, ASC 810-10-25-38A states, in part, that a quantitative approach "is not required and shall not be the sole determinant" in assessing which party is the primary beneficiary.

For certain involvements, such as certain securitization agreements, the consolidation analysis was relatively straightforward. For others, such as operating partnerships or joint ventures, the consolidation analysis was contingent upon the specific design and operations of the VIE. In these cases, the identification of the activities most significant to the VIE was inherently more difficult. The consolidation analysis has been particularly challenging for arrangements in which one party is exposed to significant risks and rewards of a VIE yet on the surface does not appear to have the power to direct the most significant activities of the VIE. The FASB added guidance in ASU 2009-17 requiring the exercise of

[2] Before becoming operational, companies performing the primary beneficiary analysis should consider whether the power to direct the VIE's most significant activities changes as entities move through discrete phases, such as development and construction. In these scenarios, the relative certainty of successfully completing each stage will most likely be relevant to the analysis. Refer to Q&A 4 in Deloitte's October 20, 2010, *Heads Up* for more information on assessing VIEs that go through discrete operational stages or phases of development.

additional skepticism when the relative economic interest of the parties to an arrangement is inconsistent with the stated power of each party involved with the VIE. Furthermore, the SEC has publicly commented that it will scrutinize the accounting for such arrangements, particularly when a transaction lacks economic substance, appears to be motivated by a desire to deconsolidate, or both.

Once companies identified a VIE that needed to be consolidated, their attention soon turned to operational and financial reporting aspects of consolidating VIEs for the first time. Depending on the type of entity being consolidated and its involvement and interests held, the consolidation process may have taken just a few days or upwards of one year. Some companies were able to prepare VIE consolidations by using spreadsheet tools, while others were required to make significant changes to systems and reporting tools.

A significant challenge companies faced was access to the VIE's financial information. In some cases, it was a matter of receiving financial information for the VIE timely. In these cases, some companies reported VIEs on a lag (e.g., used a VIE's February information for the March quarter-end consolidation). In other cases, financial information was not available to the VI holder because the trustee, or other party, was not willing to share such information related to the VIE. In these cases, companies may have developed models on the basis of known financial data and estimates for certain unknown financial data. Companies faced with this scenario often found that the creation of U.S. GAAP financial statements for a VIE was challenging and required significant effort.

Public companies required to consolidate a VIE also faced internal control challenges under the Sarbanes-Oxley Act of 2002 to the extent that financial information processing was outside the control of the company. On April 19, 2010, the CAQ released Alert #2010-21, which addressed views the SEC staff shared with the CAQ SEC Regulations Committee regarding entities consolidated under the guidance of ASU 2009-17. In short, the SEC staff stated that VIEs consolidated upon adoption of ASU 2009-17 should be covered by management's report on internal control over financial reporting. Because ASU 2009-17's guidance focuses on control, registrants would not be able to exclude consolidated VIEs from the scope of their internal control assessments given that the primary beneficiary most likely has the right or authority to assess internal control at the VIE. Some companies were able to rely on SAS 70 reports. Others had to expand the scope of their internal control assessment and developed processes to gain sufficient comfort over the financial information being consolidated in the registrant's financial statements.

In addition to these challenges, ASU 2009-17 also presented certain financial reporting challenges. Because of the difficulty entities had applying the guidance to historical involvements, the FASB did not require retrospective application. Although retrospective application was allowed, most companies in the industry applied ASU 2009-17 prospectively. This resulted in significant comparability issues between 2009 and 2010 financial statements depending on the company and the nature and significance of VIEs being consolidated. The consolidation of VIEs also created, in certain situations, other issues such as debt compliance breeches or regulatory issues.

Because ASU 2009-17 requires separate presentation of consolidated assets that can only be used to settle obligations of the consolidated VIE and consolidated liabilities for which creditors or beneficial interest holders do not have recourse against the general credit of the beneficiary, companies used a variety of approaches to separate presentation, including parenthetical display, individual line items, and mini-balance-sheet presentations (i.e., a separate balance sheet of just consolidated VIEs meeting the separate presentation requirements).

Companies with significant involvements in VIEs found that the initial adoption was very time consuming. However, given that ASU 2009-17 requires continual reconsideration of the conclusion regarding which VI holder is the primary beneficiary, the application of ASU 2009-17 is ongoing.[3] Accordingly, conclusions about consolidation may change as a result of changes in the activities or operations of the VIE. This is much different from the previous consolidation model, which required reconsideration only in certain limited situations.

Note also that after implementation, many companies have evaluated whether the processes they put in place for the initial adoption continue to be sustainable and offer adequate control over financial reporting or whether longer term solutions are warranted and should be designed and implemented.

For additional insight on and interpretations related to the challenges of applying ASU 2009-17, see Deloitte's Consolidation of Variable Interest Entities — A Roadmap to Applying the Variable Interest Entity Consolidation Model.

Industry and Other Considerations

In the energy and resources industry, Deloitte has seen involvements with sale-leaseback trusts, accounts receivable factoring special-purpose entities, rail car leases, capital leases, and other involvements consolidated for the first time in 2010 as a result of ASU 2009-17. In many of these situations, the consolidation conclusion was challenging because of the difficulty assessing the economics of the VIE as well as obtaining financial information related to the underlying entities or trusts established to hold the assets as well as the related debt. Certain industry-specific and other considerations related to the new consolidation model are discussed below. Although the items discussed below do not represent a comprehensive discussion of all industry-specific considerations, a discussion of these considerations with an entity's audit team is encouraged if they apply to the entity's organization.

Power Purchase Agreements and Tolling Arrangements

PPAs and tolling arrangements can be particularly challenging in the VI assessment. Relevant considerations include the nature of the pricing (fixed, market, cost-reimbursement, etc.), features involving the underlying plant (puts, calls, residual value guarantees) and the accounting designation of the contract (lease, derivative, other). Comparability is somewhat hindered because the VI analysis for identical contracts may differ depending on an entity's approach to assessing variability. Specifically, the conclusion reached under a cash flow view of variability will often be different from that under a fair value view. Operating entities (including power plant entities) often assess variability by using the cash flow approach. Deloitte has issued interpretive guidance that entities may find useful in assessing PPAs and tolling arrangements; this guidance did not change with the issuance of ASU 2009-17 and can be found in 810-10-25 (Q&A 31) in Deloitte's *FASB Accounting Standards Codification Manual* (available on Technical Library: The Deloitte Accounting Research Tool).

Specific considerations related to PPAs include, but are not limited to, the following:

> *Operating lease scope exception* — It is not uncommon for PPAs and tolling arrangements to be classified as leases for accounting purposes. It is important to remember that the exception for certain operating leases discussed in paragraph B24 of Interpretation 46(R), while still applicable under ASU 2009-17, only applies to the lease element of an arrangement and that therefore PPAs that meet the operating lease criteria may still contain VIs that absorb variability. Examples of these VIs include a variable energy payment, fixed price put or call option, or dismantlement or decommissioning obligations.

[3] Note that reconsideration of whether an entity is a VIE is still based on the specific triggering events listed in ASC 810-10-35-4.

Capital leases — Capital leases (including some PPAs and tolling arrangements) are generally not eligible for the operating lease scope exception, and often the features that trigger capital lease accounting (e.g., bargain purchase option, residual value guarantee) will be absorbers of variability leading one to conclude that the contract is a VI. Capital lease accounting should not be thought of as a "safety net" that minimizes the relevance of, or negates the need for, the consolidation analysis.

Avoided cost pricing — In accordance with the Public Utility Regulatory Policies Act and the Energy Policy Act, it is not uncommon for utilities to purchase power from qualifying facilities under avoided cost pricing structures. Given that avoided cost is generally a measure of the utility's marginal cost to produce the same amount of energy through construction of a new plant and does not provide for direct reimbursement for any of the generator's actual costs of production, it is believed that avoided cost pricing will not absorb risk of the generator; however, there may be exceptions. Relevant considerations include the fuel source and operating profile of the utility's marginal unit compared with the fuel source and operating profile of the generator and the reset period for the price schedule. In circumstances in which the fuel source and operating profile of the utility's marginal unit closely mirror that of the generator and in which the reset period on the pricing is frequent (e.g., monthly), it may be appropriate to conclude that the PPA is absorbing variability in the entity. A correlation analysis may be helpful to entities in making this determination.

Inflation escalators — PPAs sometimes contain inflation escalators that serve to adjust the energy charge element of the contract. For example, a PPA may provide for a fixed charge per kWh that escalates annually on the basis of changes in the Consumer Price Index. In these cases, the contract generally is not absorbing variability of the generator; rather, the fixed charge per kWh creates variability to the extent that actual variable operations and maintenance costs differ from the off-taker's price. The inflation escalator does not directly absorb cash flow variability of the seller.

Unique Considerations for Renewable Energy PPAs

Many companies have historically concluded that fixed price PPAs (e.g., fixed price per unit delivered with no cost-pass-through mechanism) do not represent VIs. This view is based on a cash flow approach to variability in the VIE and the conclusion that a fixed price PPA does not absorb such variability (e.g., variable production costs, such as fuel and operations and maintenance). Although ASU 2009-17 does not change the assessment of a VI in this context (the guidance in FSP FIN 46(R)–6, as well as guidance related to forward contracts and operating leases, continues to be authoritative U.S. GAAP in this area), ASU 2009-17 has led some to question the application of a cash flow view of variability involving entities with very little cash flow exposure. Renewable energy resources have significantly lower variable production costs than traditional fossil-fuel generating units given their lower variable operations and maintenance cost profile and the absence of fuel cost. Although situations are not expected to occur in which variable production costs are deemed nominal, to the extent that they do occur, it may be appropriate to conclude that a fixed-price-per-unit contract absorbs variability by analogy to the guidance in ASC 810-10-55-28, which states, in part:

> A forward contract to sell assets that are owned by the [entity] at a fixed price will usually absorb the variability in the fair value of the asset that is the subject of the contract.

Although electricity is not an owned asset of the VIE, if production costs are nominal, it may be acceptable to focus on the fair value variability of the electricity as opposed to the cash flow variability inherent in the generation process.

While either approach to assessing variability for these arrangements may be acceptable, in some cases it may be advisable to perform a primary beneficiary analysis, under a "belt-and-suspenders" approach, in which it is assumed that the PPA is a VI. Given the noncontrollable risks (i.e., risks for which there are no related activities) in typical renewable structures (e.g., electricity price risk), an off-taker may often conclude that it does not have power over the activities that have the most significant impact on economic performance because the power over controllable risks (such as operations and maintenance) frequently rest with the owner-operator. This will of course depend on the particular terms of each arrangement, and a different conclusion may be reached if the variability absorbed by the off-taker is so significant that the other interest holders, as a group, do not have more than an insignificant amount of exposure to the entity's variability.

In practice, many PPAs whose terms ostensibly specify a fixed price per unit often have features designed to absorb cash flow variability. For example, construction overrun contingencies or tax contingencies that can change the fixed price per unit of the facility's output would appear to be designed to absorb variability in the entity. It is important to ensure that the PPA truly involves a fixed price per unit in the conclusion that a contract does not absorb cash flow variability.

Questions have also been asked about the impact of voluntary or economic curtailment on the VI assessment, specifically whether, if the penalty pricing for economic curtailment is the same as the pricing that would have been due had the unit generated power, the off-taker has absorbed variability in the entity. Generally, this type of penalty pricing would most likely not, in and of itself, make a PPA a VI because the off-taker is not absorbing incremental cash flow variability in curtailment scenarios.

Service Provider Fees

ASU 2009-17 modified the VI assessment in the area of service-provider and decision-maker fees. Although the new guidance generally may not significantly affect single-plant entities, there may be some exceptions. For example, large-dollar service relationships, such as a long-term service agreement for turbine maintenance or an engineering procurement and construction contract for new construction, may have fees that are deemed significant relative to the entity's anticipated economic performance. As a general rule of thumb, 10 percent of the total anticipated economic performance of the entity has been used in assessing significance in this context. However, note that this percentage is not a bright line, and fees greater than or lower than 10 percent may be deemed significant depending on the facts and circumstances.

The Business Scope Exception

Single-plant entities most likely do not qualify for the business scope exception. While these entities may meet the revised definition of a business under ASC 805, they typically will fail one or more of the four conditions outlined in ASC 810-10-15-17, which preclude the use of the exception. This area did not change as a result of ASU 2009-17.

[1] Deloitte's August 17, 2010, *Heads Up* on the proposed ASU includes examples of both lessee and lessor accounting as well as the related journal entries.

Flip Structures/Tax Equity

The prevalence of tax equity in renewable "flip" structures has led to questions about whether tax equity qualifies as equity at risk. The answer can affect the VIE determination because it relates to equity sufficiency and the requirement that equity holders have an obligation to absorb losses and a right to receive benefits of the entity. Tax equity will generally represent investment at risk unless the return of the tax investor is somehow guaranteed. Disproportionate equity distributions until a flip date, in isolation, would most likely not constitute a guarantee on the tax investor's return.

Jointly-Owned Plants

Generally, ASU 2009-17 did not affect the application of proportional consolidation accounting for ownership interests in jointly-owned plants. Such arrangements involve undivided interests in an asset as opposed to discrete ownership or other contractual interests in a separate legal entity. On the other hand, a lease of an undivided interest held by a trust or other legal entity will often require a consolidation analysis by the lessee under ASU 2009-17.

Transfers of Financial Assets

The FASB issued ASU 2009-16 to "improve the relevance, representational faithfulness, and comparability of the information" about (1) the transfer of financial assets that are included in an entity's financial statements; (2) the effects of a transfer of financial assets on the entity's financial position, financial performance, and cash flows; and (3) the continuing involvement of the transferor of financial assets. ASU 2009-16 became effective for financial asset transfers occurring after the beginning of an entity's first fiscal year that began after November 15, 2009. For December 31, 2009, year-end entities, the effective date was January 1, 2010.

Industry Considerations

Sales of accounts receivable tend to be the most common type of transaction this guidance applies to in the P&U sector. Recently, questions have arisen about how the cash flows related to the sales of accounts receivable should be presented in the statement of cash flows upon adoption of ASU 2009-16. The following is a discussion of the cash flow implications in a variety of scenarios in which an entity sells all or a portion of its accounts receivable.

Statement of Cash Flows Presentation When Consolidation of a CP SPE Is Not Required Upon Adoption of ASU 2009-17

ASU 2009-17 amended the guidance in ASC 810. Among other changes, it amended the guidance on consolidation of VIEs by requiring entities to assess consolidation on the basis of control over the VIE's activities as opposed to a consolidation framework based on the assessment of risks and rewards. ASU 2009-17 also eliminated the exception from consolidation that applied to QSPEs.

Presentation Under Financing Arrangements That Involve a Transfer of an Entire Group of Trade Receivables

When an entity transfers an entire group of trade receivables to a nonconsolidated commercial paper special-purpose entity (the "CP SPE"), and those transfers meet the conditions for sale accounting under ASC 860 (as amended by ASU 2009-16), it should present cash flows between the transferring entity and the CP SPE in the statement of cash flows as follows:

- Cash received from sales of trade receivables to the CP SPE represents an operating activity in accordance with ASC 230-10-45-16(a). The deferred purchase price (DPP) received upon sales of trade receivables to the CP SPE represents a noncash transaction that is disclosed in accordance with ASC 230-10-50-3 through 50-6.

- Cash received from collections on the DPP represents an investing or an operating activity. The transferring entity will account for the DPP as a debt security or a receivable held for investment (or held for collection). A DPP is accounted for as a receivable if it is not certificated and does not have to be accounted for as a debt security under ASC 860-20-35-2. Typically, cash collections on an available-for-sale security represent an investing activity in accordance with ASC 230-10-45-11. Cash collections on a trading security that was not acquired specifically for resale also typically represent an investing activity in accordance with ASC 230-10-45-19. Cash collections on a trade receivable are typically classified as an operating activity. However, because of the nature of the DPP, the cash received from collections on the DPP may be classified as either operating or investing cash flows, on the basis of an accounting policy election made by the entity, regardless of whether the DPP is accounted for as a security or a receivable. Regardless of the cash flow statement classification, entities should present the cash flow activity on the DPP as a separate line item in the statement of cash flows and should disclose the accounting policy applied.

Presentation Under Financing Arrangement That Involve a Transfer of Portions of an Entire Group of Trade Receivables

When an entity transfers portions of an entire group of trade receivables to a nonconsolidated CP SPE, it will not meet the conditions for sale accounting under ASU 2009-16 because the transferred portion does not meet the definition of a participating interest. Even though the CP SPE is not consolidated by the transferring entity, such transfers must be accounted for as a secured borrowing after the effective date of ASU 2009-16. The provisions of ASU 2009-16 must be applied prospectively to transfers that occur on or after the effective date of ASU 2009-16 (i.e., January 1, 2010, for a calendar-year entity). Under this transition guidance, the historical accounting for these types of transfers is not affected (i.e., the portion of the trade receivables previously transferred that were historically reflected as derecognized financial assets for accounting purposes will continue to be reflected as such). After the effective date of ASU 2009-16, the entity will reflect these transfers as a secured borrowing (i.e., the portion of the trade receivables transferred will remain on the balance sheet of the transferring entity, and a liability will be recognized for the cash proceeds received upon transfer). Recognition of the adoption of ASU 2009-16 retrospectively, or as a cumulative effect of a change in accounting principle, is prohibited.

While the adoption of ASU 2009-16 will not affect previously reported amounts in the statement of cash flows, it will change the presentation on and after the effective date. The following presentation will be required after adoption of ASU 2009-16:

- Cash received from the CP SPE upon transfers of senior undivided interests (which is reflected on the balance sheet as a secured borrowing) represents a financing activity in accordance with ASC 230-10-45-14(b).

- Cash paid to the CP SPE to reflect the repayment of the principal amount of the senior undivided interests (i.e., the secured borrowing) represents a financing activity in accordance with ASC 230-10-45-15(b). This financing cash outflow can be netted with the financial cash inflow (discussed above) only if the requirements in ASC 230-10-45-7 through 45-9 are met.

- Cash paid as interest on the senior undivided interests (i.e., the secured borrowing) represents an operating activity in accordance with ASC 230-10-45-17(d).

- Cash received from customers upon payment of the trade receivables represents an operating activity in accordance with ASC 230-10-45-16(a).

Application of the amended guidance in ASC 860 will uniquely affect the statement of cash flows of the transferring entity during the period(s) between (1) the initial adoption date of ASU 2009-16 and (2) the date that full collection on receivables transferred before the adoption of ASU 2009-16 has occurred. During this period, the transferring entity will generally reflect a reduced amount of operating cash inflows from trade receivables. This phenomenon occurs because after adoption of ASU 2009-16, operating cash inflows are reflected only upon collection of trade receivables; before adoption of ASU 2009-16, operating cash flows were reflected upon transfers of senior undivided interests to the CP SPE. A timing difference will occur because cash received from collections on previously sold trade receivables will not be reflected as an operating cash inflow. Only cash received from collections on trade receivables transferred to the CP SPE after the adoption of ASU 2009-16 will be reflected as an operating cash inflow. In addition, in periods after adoption of ASU 2009-16, financing cash inflows and outflows will be reported that were not reported previously. For example, the establishment of a secured borrowing for the undivided senior interests transferred after the effective date of ASU 2009-16 will be reflected as a financing cash inflow. Entities should be cognizant of the requirements in SEC Regulations S-K and S-X to disclose significant transactions and items that may have a material impact on reported results or that have a material impact on the trends of reported information.

Statement of Cash Flows Presentation When Consolidation of the CP SPE Is Required Upon Adoption of ASU 2009-17

Presentation Under Financing Arrangements That Involve a Transfer of an Entire Group of Trade Receivables

When an entire group of trade receivables is transferred to the CP SPE, the transferring entity may conclude that it is required to consolidate the CP SPE upon adoption of ASU 2009-17. Under ASC 810-10-65-2, the entity can choose one of two transition methods to reflect this consolidation: (1) the change-in-accounting-principle method or (2) the retrospective method. The impact of each method on the statement of cash flows is addressed below.

1. *Change-in-accounting-principle method* — Under this transition method, the entity must reflect the initial consolidation of the CP SPE as a cumulative effect of a change in accounting principle. As long as there is no unrestricted cash in the CP SPE, this cumulative-effect adjustment will not affect operating, investing, or financing activities in the statement of cash flows in the period recorded, but it should be disclosed as a noncash transaction in accordance with ASC 230-10-50-3 through 50-6. After initial consolidation, cash flows related to the trade receivable financing arrangement should be presented as follows:

    - Cash received upon the CP SPE's issuance of commercial paper will represent a financing activity in accordance with ASC 230-10-45-14(b).

- Cash paid on principal amounts due to the third-party beneficial interest holders in the CP SPE (i.e., on the commercial paper) represents a financing activity in accordance with ASC 230-10-45-15(b). This financing cash outflow can be presented on a net basis with the financing cash inflow (discussed above) only if the requirements in ASC 230-10-45-7 through 45-9 are met.

- Cash paid as interest on the commercial paper issued by the CP SPE represents an operating activity in accordance with ASC 230-10-45-17(d).

- Cash received from customers upon payment of the trade receivables represents an operating activity in accordance with ASC 230-10-45-16(a).

2. *Retrospective method* — Under this transition method, the entity must retrospectively reflect consolidation of the CP SPE in its historical financial statements. This will involve adjusting the historical statements of cash flows. The amounts should be adjusted retrospectively to reflect the presentations listed above for the change-in-accounting-principle method.

Note that although the presentation requirements for cash flows occurring after the effective date of ASU 2009-17 are similar under the two transition methods, the method adopted will affect the amounts reported on the entity's statement of cash flows after the effective date of ASU 2009-17. First, under the change-in-accounting-principle method, collections on trade receivables previously considered sold before the adoption of ASU 2009-17 will be reflected as an operating cash inflow even though an operating cash inflow has already been reflected on those same trade receivables in periods before adoption of ASU 2009-17. Second, a financing cash outflow will be reflected upon repayment of the principal amount of the third-party beneficial interests in the CP SPE even though a financing cash inflow on the issuance of these third-party beneficial interests was not previously reflected. Entities should be cognizant of the requirements in SEC Regulations S-K and S-X to disclose significant transactions and items that may have a material impact on reported results or that have a material effect on the trends of reported information.

Multiple-Deliverable Revenue Arrangements

In October 2009, the FASB issued ASU 2009-13 on multiple-deliverable revenue arrangements. The ASU amends ASC 605-25 and applies to all deliverables in contractual arrangements in all industries in which a vendor will perform multiple revenue-generating activities, except when some or all deliverables in a multiple-deliverable arrangement are within the scope of other, more specific ASC sections (e.g., ASC 840, ASC 952, ASC 360-20, and other sections of ASC 605 on revenue recognition).

Specifically, ASU 2009-13 addresses the unit of accounting for arrangements involving multiple deliverables. It also addresses how arrangement consideration should be allocated to the separate units of accounting, when applicable. However, guidance on determining when the criteria for revenue recognition are met and on how an entity should recognize revenue for a given unit of accounting (e.g., SAB Topic 13) is contained elsewhere in U.S. GAAP. Although ASU 2009-13 retains the criteria from ASC 605-25 for when delivered items in a multiple-deliverable arrangement should be considered separate units of accounting, it removes the separation criterion that objective and reliable evidence of the fair value of any undelivered items must exist for the delivered items to be considered a separate unit or separate units of accounting. Accordingly, ASU 2009-13 enables entities to separately account for individual deliverables for many more revenue arrangements. Because the ASU removes the criterion that entities must use objective and reliable evidence of fair value in separately accounting for deliverables, recognition of revenue is expected to more closely align with the economics of certain revenue arrangements.

ASU 2009-13 discusses how an entity should allocate arrangement consideration to separate units of accounting. In doing so, entities are required, at the inception of an arrangement, to establish the "selling price" for all deliverables that qualify for separation. The manner in which "selling price" is established is based on a hierarchy of evidence that entities must consider. Total arrangement consideration is then allocated on the basis of the deliverables' relative selling price. In considering the hierarchy of evidence under ASU 2009-13, an entity first determines the selling prices by using vendor-specific objective evidence (VSOE) of selling price, if it exists; otherwise, third-party evidence (TPE) of selling price must be used. If neither VSOE nor TPE of selling price exists for a deliverable, an entity must use its best estimate of the selling price for that deliverable to allocate consideration among the deliverables in an arrangement. As stated in ASU 2009-13, in deciding whether the entity can establish VSOE or TPE of selling price, the "vendor shall not ignore information that is reasonably available without undue cost and effort."

ASU 2009-13 describes the way arrangement consideration should be allocated to the individual deliverables and states that "[a]rrangement consideration shall be allocated at the inception of the arrangement to all deliverables on the basis of their relative selling price (the relative selling price method)." Because of ASU 2009-13's new requirements that entities use a three-level hierarchy when establishing the selling price and that they use the relative-selling-price method when allocating arrangement consideration, the "residual method" under EITF 00-21 is no longer appropriate.

In addition to the accounting changes outlined above, ASU 2009-13 significantly expands the previous disclosure requirements under ASC 605-25. The ASU expanded the disclosures partly because of the significant judgment that is now required and partly because of the perception by some that disclosures under ASC 605-25 did not provide financial statement users with sufficient decision-useful information regarding multiple-deliverable revenue arrangements.

ASU 2009-13 is effective for fiscal years beginning on or after June 15, 2010. Entities can elect to apply the ASU (1) prospectively to new or materially modified arrangements after its effective date or (2) retrospectively for all periods presented. Early adoption is permitted; however, if the entity elects prospective application and early adopts the ASU after its first interim reporting period, it must also do the following in the period of adoption: (1) retrospectively apply the ASU as of the beginning of that fiscal year and (2) disclose the effect of the retrospective adjustment.

For information about industry considerations, see Section 5.

Proposed ASU, *Leases*

As part of their convergence efforts, in August 2010 the FASB and IASB issued an ED, *Leases*, which establishes a new accounting model for both lessees and lessors. The ED would eliminate the bright line tests under existing U.S. GAAP as well as the concept of operating leases. The new guidance is meant to provide users of financial statements with a clear understanding of all of an entity's leasing activities.

Scope

The ED includes 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 power purchase, storage, and transportation agreements that contain a lease. Contracts specifically identified as not within the scope of the ED include:

- Leases of intangible assets.
- Leases to explore for or use minerals, oil, natural gas, and similar nonregenerative resources.

- Leases of biological assets.

In addition, contracts that represent the purchase or sale of the underlying asset are outside the scope of the ED and would be accounted for under other U.S. GAAP. The ED describes the following as contracts that represent the purchase or sale of an underlying asset: (1) the transfer of "control of the underlying asset . . . to another entity," which would include all but a trivial amount of the risks and benefits associated with the asset, and (2) a lease under which the lessee has "exercised a purchase option specified in the lease."

The ED also includes contracts that contain both a service and a lease component unless the service component of the contract is distinct. If the service component is distinct, the lessee or lessor would apply the FASB's ED on revenue to the service component of such contracts. Note that the ED would not change the requirement to identify any nonlease elements (e.g., fuel, maintenance) and account for them in accordance with the applicable accounting guidance. However, the ED makes this point even more important because lease elements would be recorded on the balance sheet.

Lessee Accounting

The accounting model for lessees is a right-of-use approach under which an asset and a liability would be recognized by an entity for all lease contracts. If the ED is approved in its current form, the concepts of an operating lease or capital lease will go away and all leases would result in the addition of an asset and liability to the balance sheet. This is a significant change from the existing guidance.

Recognition

On the commencement date of a lease, an entity would recognize the following in its financial statements.

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 liability to make lease payments resulting from reassessment of the expected amount of contingent rentals, expected payments under term option penalties, and residual value guarantees for current or prior periods. • 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, 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 included within this calculation must also include an estimate of contingent rents, residual value guarantees, and expected payments under termination penalties between the lessee and the lessor. Under current U.S. GAAP, contingent rents are generally excluded from the calculation of minimum lease payments. The right-of-use asset is equal to the amount of such liability as well as any initial direct costs incurred by the lessee.

Note that the ED does not address the impact of lease incentives.

Measurement

Another significant change under the ED is the determination of the lease term. The ED defines the lease term as "the longest possible term that is more likely than not to occur." This would cause the lessee (and lessor) to consider the likelihood of exercising lease renewal options or early termination options. Under the ED, possible considerations would include, but are not limited to:

- Contractual factors such as termination penalties or level of lease payments (e.g., bargain renewal rates).
- Noncontractual factors such as the existence of significant leasehold improvements.
- Whether the underlying asset is specialized or is crucial to the lessee's operations.
- Past experience of the entity or the entity's intentions.

Under existing U.S. GAAP, renewal options are included only if "reasonably assured."

Example

The following example, adapted from paragraph B17 of the proposed ASU, illustrates how a lessee would determine the lease term under the proposed model.

A lessee enters into a noncancelable 10-year lease with two 5-year options to renew. On the basis of past history and other contractual and noncontractual factors specific to the leased asset, the entity has assigned the following probabilities to each of the potential terms:

- A 40 percent probability of a 10-year term.
- A 30 percent probability of a 15-year term.
- A 30 percent probability of a 20-year term.

There is a 30 percent probability of a 20-year term, a 60 percent probability of at least a 15-year term, and a 100 percent probability that the term will be at least 10 years. Therefore, the longest possible term more likely than not to occur is 15 years.

Subsequent Measurement

A lessee will amortize the right-of-use asset over the shorter of the useful life of the underlying asset or through the end of the lease term, as defined above. Using the interest method to recognize the obligation at amortized cost, the lessee will also record interest expense on the outstanding obligation. The recognition of these expenses by the lessee replaces "rent expense" under the existing guidance, and the expense will no longer be equal in all periods because the interest expense will be higher in the earlier periods than in the later periods. A lessee will also need to evaluate the right-of-use asset for impairment under ASC 350.

Further, 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. This is a significant change from the current guidance. Changes to contingent rents, residual value guarantees, 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.[4]

Presentation

Within the statement of financial position, the obligation to make lease payments should be presented separately from other financial liabilities. The right-of-use asset should be shown as a component of PP&E; however, it should be shown separately from assets that are owned by the entity.

Either on the income statement, or within the notes to the financial statements, the entity should present the amortization of the right-of-use asset and the interest expense on the liability to make lease payments. Note that these expense amounts should be shown separately from amortization and interest expense amounts not related to leasing activities.

Cash payments for leases should be included as a financing activity within the statement of cash flows, separately from other financing activities.

Lessor Accounting

The ED describes two accounting models whose use depends on whether a lessor retains exposure to significant risks or benefits associated with the underlying asset. The lessor would use (1) the performance obligation approach when exposure is retained and (2) the derecognition approach when exposure is not retained. Note that lessor accounting would also apply to sellers of power under a contract that contains a lease.

Performance Obligation Approach

Recognition

On the commencement date of a lease, the lessor would record the following in its financial statements.

Statement	Items to Recognize
Statement of financial position	• Underlying asset remains on books. • Asset — right to receive lease payments. • Lease liability — obligation to permit the lessee to use the asset over the lease term.

Statement	Items to Recognize

[4] Deloitte's August 17, 2010, *Heads Up* on the proposed ASU includes examples of both lessee and lessor accounting as well as the related journal entries.

Income statement	• Interest income on the right to receive lease payments. • Lease income (included in revenue if the lease is a part of ongoing or major activities). • Changes to the lease liability resulting from reassessment of the expected amount of contingent rentals, expected payments under term option penalties, and residual value guarantees for current or prior periods. • Impairment losses on right to receive lease payments (if necessary).

Measurement

The right to receive lease payments is measured as the sum of the present value of lease payments discounted by the rate the lessor is charging the lessee. Further, the lease liability is measured as the present value of lease payments discounted by the rate the lessor is charging the lessee. Contingent rentals, residual value guarantees, and expected payments under termination penalties are included in the measurement if they can be "reliably measured." Many believe that for renewable energy contracts (i.e., wind, solar), a site survey may meet the criteria for "reliably measured."

Subsequent Measurement and Reassessment

The lessor would amortize (1) the asset for the right to receive lease payments by using the interest method to recognize interest income and (2) the performance obligation by using a systematic and rational approach (e.g., units of production, hours of use) or straight-line approach in the absence of a reliable method based on a pattern of use. The lessor would also evaluate the asset representing the right to receive lease payments under ASC 310 each reporting period to determine whether the asset is impaired.

Further, each reporting period, the lessor should evaluate the asset to determine whether "facts or circumstances indicate that there would be a significant change in the right to receive lease payments since the previous reporting period." Should there be a change in the right to receive lease payments as result of a change in estimate related to the lease term, the lessor would make a corresponding adjustment to the liability. Changes to contingent rents, residual value guarantees, or termination penalties would be recognized through (1) income if the lessor has satisfied the related lease liability or (2) an adjustment to the lease liability if the lessor has not satisfied the lease liability. Any changes that would reduce the liability below zero would be included within the income statement.[5]

Presentation

Under this approach, the lessor would have the following items in its statement of financial position:

- The underlying asset.
- Right to receive lease payments.
- Lease liability.

The sum of these items would be shown as a net lease asset or a net lease liability in the statement of financial position.

[5] See footnote 4.

The lessor would record in the income statement the interest income on the right to receive lease payments, lease income, and depreciation expense on the underlying asset. These amounts would be summed to net lease income or net lease expense in the income statement.

Cash receipts from lessees would be included within operating activities on the statement of cash flows of the lessor.

Note that the ED does not provide guidance on the accounting for subleases other than to note that an entity would account for the original lease of the asset under the lessee model and for the sublease of the asset under the lessor model.

Derecognition Approach

Under the derecognition approach, a lessor removes the underlying asset from its statement of financial position (or portion thereof) because the lessor does not retain a significant portion of the risks or benefits associated with the asset.

Recognition

On the commencement date of a lease, the lessor would recognize the following in its financial statements.

Statement	Items to Recognize
Statement of financial position	• Asset — right to receive lease payments. • Derecognize the underlying asset (or portion thereof). • Reclassify the remaining portion of the asset as a residual asset.
Income statement	• Interest income on the right to receive lease payments. • Lease income (included in revenue if the lease is a part of ongoing or major activities). • Changes to the lease liability resulting from reassessment of the expected amount of contingent rentals, expected payments under term option penalties, and residual value guarantees for current or prior periods. • Impairment losses on right to receive lease payments (if necessary).

Measurement

The right to receive lease payments is measured as the sum of the present value of lease payments discounted by the rate that the lessor is charging the lessee. The residual asset is measured at an allocated amount of the carrying amount of the asset as of the date of the inception of the lease. The amount of the asset derecognized is calculated as follows:

$$\frac{\text{Fair value of the right to receive lease payments}}{\text{Fair value of the underlying asset}} \times \text{Carrying amount of the underlying asset}$$

The amount of the underlying asset that is not derecognized is the residual asset.

Subsequent Measurement and Reassessment

The lessor would amortize the asset for the right to receive lease payments by using the interest method to recognize interest income. The residual asset is not remeasured unless there is a change to the term of the lease or the asset becomes impaired. The lessor would also evaluate the asset representing the right to receive lease payments under ASC 310 each reporting period to determine whether the asset is impaired. In addition, under the derecognition approach, the entity would evaluate the residual asset under ASC 350 to determine whether the asset has become impaired.

Further, each reporting period, the lessor should evaluate the asset to determine whether "facts or circumstances indicate that there would be a significant change in the right to receive lease payments since the previous reporting period." If such indicators exist, the lease term should be reassessed. Should there be a change in the residual asset as a result of the reassessment, the lessor would allocate the change to the "rights derecognized and the residual asset . . . and adjust the carrying amount of the residual asset accordingly." Changes to contingent rents, residual value guarantees, or termination penalties would be recognized through the income statement.[6]

Presentation

Under this approach, the lessor would have the following items in its statement of financial position:

- Right to receive lease payments (shown separately from other financial assets).
- Residual asset (shown as a separate component of property, plant, and equipment).

The lessor would record in the income statement the lease income, and lease expense, either in separate line items or netted, depending upon the lessor's business model. If the asset is a good that is generally sold by the lessor, the lease income and lease expense should be presented gross. However, if the lease is in place to facilitate financing, the lessor is permitted to use net presentation.

Cash receipts from lessees would be included within operating activities in the statement of cash flows of the lessor.

Other Miscellaneous Concepts

Short-Term Leases

On the commencement date of a lease, the lessee can elect to record a short-term lease at the undiscounted amounts. The ED defines a short-term lease as a "lease that, at the date of commencement of the lease, has a maximum possible lease term, including options to renew or extend, of 12 months or less." Similarly, a lessor may elect to not recognize lease assets or liabilities of a short-term lease. The lease payments will be recognized by either the lessee or the lessor in the income statement of the lease term. The election of the treatment for short-term leases is made on a lease-by-lease basis.

Leveraged Leases

The ED does not include specialized accounting, presentation, or transition guidance on leveraged leases. Leases previously reported as leveraged under U.S. GAAP would be subject to the same guidance as other leases under the ED.

[6] See footnote 4.

Sale and Leaseback Transactions

If a transaction meets the criteria for a sale, the seller (lessee) would account for (1) the transaction as a sale in accordance with applicable guidance and (2) the lease in accordance with the above lessee guidance. If the transaction does not meet the criteria for a sale, such transaction would be accounted for as a financing. If the transaction meets the criteria for a purchase, the acquirer (lessor) would account for (1) the transaction as a purchase in accordance with applicable guidance and (2) the lease in accordance with the performance obligation approach described above. If the criteria for purchase accounting are not met, the acquirer would not recognize the asset and would recognize the amount paid as a receivable.

Disclosure

The ED would significantly increase the amount of disclosure an entity would be required to provide on leases. An entity would be required to disclose both quantitative and qualitative information to enable financial statements users to understand the expected cash flows related to leasing activities. Information should be aggregated or disaggregated to be meaningful and not obscured by other nonleasing transactions. Qualitative information that would be meaningful to users of the financial statements may include contingent rentals, renewal options, and residual value guarantees. Entities should also disclose significant assumptions, and changes to assumptions, including discount rate, renewal options, contingent rentals, and residual value guarantees.

Tax Considerations

The ED would require an entity to recognize, for book purposes, new assets and liabilities that would not be recognized for tax purposes, thus resulting in a basis difference and a corresponding deferred tax asset or liability.

Note that although the lease asset and liability may initially be measured and recorded at the same amount, resulting in an entity concluding that no deferred tax is required, an 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, it will be important for entities not to confuse the proposed change in the accounting rules when they prepare their income tax returns and supporting schedules. For example, 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.

Effective Date and Transition

An effective date has not yet been established for the ED; however, the FASB will consider the effective date upon its review of comments received on the ED. The FASB expects to issue a final ASU during the first half of 2011.

Entities will be required to apply the ED's guidance to all contracts outstanding as of "the beginning of the first comparative period presented in the first financial statements in which the entity applies this guidance." Unlike EITF 01-8 (codified in ASC 840-10), the ED does not appear to allow for grandfathering of existing lease contracts and, therefore, entities would apply the guidance in the ED to all contracts outstanding for the periods described above. Further clarification about this grandfathering concept may be forthcoming because the FASB has stated that it did not intend to change the scope with this ED. Note that entities should consider the implication of this guidance on the five-year summary table as well.

Industry Considerations

Entities should also consider the following in light of the ED:

- 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.
- Balance sheet ratios will change — specifically the debt-to-equity ratio. Entities may want to consider any regulatory impact of these changes before applying the ED's guidance.
- Debt covenants, such as the interest coverage ratio, may require additional consideration as a result of the changes in accounting under ED.
- 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.
- All PPAs, including renewable power contracts, and storage and transportation agreements.

Exposure Draft — Revenue From Contracts With Customers

On June 24, 2010, the FASB and IASB jointly issued an ED, *Revenue From Contracts With Customers*. The ED, released by the FASB as a proposed ASU, gives 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 proposed ASU, which would apply to any entity that enters into contracts to provide goods or services, would supersede most of the current revenue recognition guidance, including many industry-specific rules that have emerged over the years. Of note to the energy industry is that EITF Issues addressing both sales under long-term PPAs and accounting for alternative revenue arrangements would be superseded by the new guidance. These issues are further discussed below under "Industry Considerations." Real estate sales rules would also be superseded, which may affect certain transactions in the industry involving generating assets because these often meet the existing U.S. GAAP definition of "integral equipment."

The core principle under the proposed ASU is that an entity must "recognize revenue to depict the transfer of goods or services to customers in an amount that reflects the consideration that it receives, or expects to receive, in exchange for those goods or services."

The scope of the proposed ASU includes all contracts with customers except (1) those within the scope of ASC 840 (on leases) or ASC 944 (on insurance), (2) certain contractual rights or obligations within the scope of other ASC topics, (3) guarantees (other than product warranties) within the scope ASC 460, and (4) nonmonetary exchanges whose purpose is to facilitate a sale to another party. In applying the provisions of the proposed ASU to contracts within its scope, an entity would:

(a) identify the contract(s) with a customer;

(b) identify the separate performance obligations in the contract;

(c) determine the transaction price;

(d) allocate the transaction price to the separate performance obligations; and

(e) recognize revenue when the entity satisfies each performance obligation.

Identifying the Contract With the Customer

A contract can be written, verbal, or implied; however, the proposed ASU only applies to a contract if:

(a) the contract has commercial substance (that is, the entity's future cash flows are expected to change as a result of the contract);

(b) the parties to the contract have approved the contract and are committed to satisfying their respective obligations;

(c) the entity can identify each party's enforceable rights regarding the goods or services to be transferred; and

(d) the entity can identify the terms and manner of payment for those goods or services.

While an entity would most likely apply the provisions of the proposed ASU to a single contract, in certain circumstances the entity may need to combine a group of contracts or segment a single contract.

The proposed ASU provides guidance on determining whether goods or services are priced interdependently or independently. Further, contract modifications are accounted for as separate contracts only if they are priced independently of the original contract. Otherwise, contract modifications are accounted for together with the original contract, and the cumulative effect of the modification is recognized in the period in which the modification occurs.

Identifying Distinct Performance Obligations

Under the proposed ASU, an "entity shall evaluate the terms of the contract and its customary business practice to identify all promised goods or services and determine whether to account for each promised good or service as a separate performance obligation." Although the proposed ASU does not define goods or services, it provides a few examples, including goods produced/purchased for sale/resale, granting a license, or performing a contractual task.

The proposed ASU indicates that a good or service is "distinct" if (1) such good or service (or a similar one) is sold separately or (2) "the entity could sell the good or service" because it has a distinct function and profit margin.

Determining the Transaction Price

The transaction price for a contract can be readily determinable if the consideration is fixed, or the price can be variable because of discounts, rebates, refunds, credits, incentives, performance bonuses/penalties, contingencies, price concessions, or other similar items. The proposed ASU requires an entity to determine the amount of consideration it expects to receive from the customer for the promised goods or services in the contract. If such amount is subject to variability, an entity is required to use an estimated transaction price (based on a probability weighting) if it can reasonably be estimated. Otherwise, the transaction price would be limited to the amount that is fixed or can be reasonably estimated.

Under existing revenue recognition standards, entities are generally precluded from recognizing revenue until the seller's price is fixed and determinable (i.e., the consideration is no longer variable). Under the proposed ASU, entities would recognize revenue when consideration is variable (as long it is reasonably estimable). As a result, entities may recognize revenue earlier than they currently do under U.S. GAAP. In addition, because the proposed ASU requires entities to update the estimated transaction price (based on the probability-weighted estimate) each reporting period, they may have to adjust estimated revenue periodically.

Allocating the Transaction Price

The proposed ASU requires an entity to "allocate the transaction price to all separate performance obligations in proportion to the standalone selling prices of the goods or services underlying each of those performance obligations at contract inception (that is, on a relative standalone selling price basis)." The best evidence of stand-alone selling price is the price at which the good or service is sold separately by the entity. If it is not sold separately, an entity is required to estimate it by using observable inputs ("expected cost plus a margin" or "adjusted market assessment" would both be acceptable estimation methods).

Changes in the transaction price after contract inception would be allocated to **all** performance obligations in the contract, and any portion of such change allocated to satisfied performance obligations would be recognized as revenue immediately.

Recognizing Revenue When Performance Obligations Are Satisfied

The proposed ASU provides for the recognition of revenue when "the customer obtains control" of the promised good(s) or service(s) underlying a separate performance obligation (therefore satisfying the performance obligation). Under the proposed ASU, the following would indicate that a customer has obtained control of a good or service: "(a) the customer has an unconditional obligation to pay . . . (b) the customer has legal title . . . (c) the customer has physical possession . . . [and] (d) [the customer specifies] the design or function of the good or service."

The proposed ASU acknowledges that in certain circumstances the promised goods or services underlying a separate performance obligation could be continuously transferred to a customer (such as a product specifically designed for and tailored by a customer before and during construction). In such cases, an entity is required to apply a single revenue recognition method to the separate performance obligation that depicts the transfer of goods or services to the customers. Acceptable approaches noted in the proposed ASU include output methods, input methods, or methods based on the passage of time.

Other Notable Provisions

In addition to the main principles discussed above, the proposed ASU provides guidance on the accounting for certain costs as well as implementation guidance related to several areas. Some of the more significant areas are highlighted below. Other areas addressed in the proposed ASU include right of return provisions, licenses of and rights to use assets, product warranties and product liabilities, presentation of contract assets and liabilities, principal versus agent considerations, consignment arrangements, bill-and-hold arrangements, sale and repurchase of a product, nonrefundable upfront fees, and customer acceptance provisions.

The proposed ASU states that at contract inception and at each reporting date, an entity shall test the adequacy of the amount of its remaining performance obligations by comparing the transaction price allocated to each performance obligation to the expected direct costs (probability weighted) to satisfy that performance obligation. Entities would be required to recognize a contract loss to the extent that the present value of the expected direct costs of satisfying the separate performance obligation exceeds the amount of the transaction price allocated to that obligation. Such analysis would be updated on each reporting date, and changes to the contract loss would **not** be recognized as revenue.

Certain costs, such as the cost of soliciting a customer, negotiating the terms of a contract, or paying a sales commission (cost of obtaining a contract), may be incurred before the inception of a contract. Other costs are incurred to fulfill a contract, such as those incurred during set-up, delivery, or performance.

The proposed ASU requires that costs of obtaining a contract be expensed as incurred. In contrast, costs incurred in fulfilling a contract can be capitalized if such costs qualify as an asset eligible for recognition in accordance with other standards (ASC 330, ASC 360, and ASC 985 on capitalized software) or meet the following requirements:

> (a) relate directly to a contract (or a specific contract under negotiation) . . .;
>
> (b) generate or enhance resources of the entity that will be used in satisfying performance obligations in the future; and
>
> (c) are expected to be recovered.

The proposed ASU provides a list of costs considered to be related directly to a contract (i.e., direct costs), including direct labor and material, certain allocable costs, and costs explicitly chargeable to the customer. Further, costs related to satisfied performance obligations, and "abnormal amounts" of fulfillment costs, must be expensed as incurred.

Disclosures

The proposed ASU requires entities to disclose both quantitative and qualitative information about the amount, timing, and uncertainty of revenue (and related cash flows) from contracts with customers and the judgment, and changes in judgment, they exercised in applying the provisions of the proposed ASU. The disclosures required by the proposed ASU would significantly expand those currently required by existing revenue standards and would include:

- Information about the nature of customer contracts and the related accounting policies.
- A disaggregation of reported revenue (in categories that best depict how the amount, timing, and uncertainty of revenues and cash flows are affected by economic characteristics).
- A reconciliation of the beginning and ending contract assets and liabilities.
- Information about performance obligations (types of goods/services, payment terms, timing, etc.) including a run-off schedule displaying the amounts expected to be earned in the future under existing contracts as performance obligations are satisfied (broken out by year similar to a minimum lease payment table).
- Information about onerous contracts, including the extent and amount of such contracts and the reasons they became onerous.
- A description of the principal judgments used in accounting for contracts with customers.
- Information about the methods, inputs, and assumptions used in determining and allocating the transaction prices.

Effective Date and Transition

The proposed ASU would be applied retrospectively in accordance with ASC 250. The effective date has yet to be determined. The FASB expects to issue a final ASU during the first half of 2011.

Industry Considerations

Long-Term Power Sales Contracts

As stated above, the proposed ASU 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 all 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 (e.g., will each individual kWh delivered be a separate performance obligation? Can delivery of kWh over a period be considered a separate performance obligation? 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, significant estimates in the determination of the stand-alone selling price for separate performance obligations may be required (i.e., potentially forecasting costs by using an "expected cost plus margin" method or estimating the forward curve for an entire contract period under an "adjusted market assessment" method).

Entities with contracts containing terms that cause variability in pricing and quantity over a contract period may need to be able to reasonably estimate future prices and quantities to recognize revenue as billed or in a manner similar to current U.S. GAAP. Recognizing variable revenue may not be as simple as recording the billed amount over a given period. Price changes within a long-term contract (either by the terms of the contract, changes in estimates, or modification by the parties) may need to be allocated (or reallocated) to **all** performance obligations (both previously satisfied and remaining obligations) in the contract. Accordingly, application of the proposed guidance may create additional volatility in an entity's financial reporting.

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 relative to the timing of customer payments. To the extent that a material financing component exists, entities will need to adjust revenue for such financing component and recognize interest income or expense accordingly.

Accounting for Alternative Revenue Programs

The proposed ASU would supersede ASC 980-605, which includes the guidance addressing alternative revenue programs, such as decoupling programs and incentive revenue plans, and allows for revenue accrual if specified conditions are met. These types of arrangements are not uncommon and are expected to increase in the future as regulators implement energy-efficiency programs in connection with broader energy policy decisions. In the absence of this guidance, these programs generally would not meet the requirements that would allow a regulatory asset to be recorded under ASC 980 because they involve the accrual of revenue as opposed to the recovery of an incurred cost. Accordingly, the guidance is viewed as an important part of the regulatory accounting framework under U.S. GAAP, and respondents in the industry have asked the FASB to retain it by moving it to ASC 980. In their comments on the proposed ASU, respondents acknowledged the goal of eliminating industry-specific revenue rules, but noted that this is fundamentally a regulatory accounting issue as opposed to a revenue issue.

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 between 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 smoothes the unit price for the entire remaining delivery period (not just the add-on period). Under the proposed guidance, such a change would be considered a contract modification, and an entity would need to determine whether the modification is independent or interdependent of the original contract (as currently proposed, such determination would focus on whether a significant discount from current selling price was provided at the time of the modification). If the change is deemed independent (i.e., no significant discount on future products was provided), the modification would be accounted for as a separate contract (i.e., prospectively). If the change is deemed interdependent (i.e., a significant discount on future products was provided), an entity would account for the modification as if the new terms existed at the contract's inception (i.e., retrospectively) and would allocate the new transaction price to both satisfied and remaining performance obligations.

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). It is unclear whether the guidance in the ED on the time value of money was meant to apply to forward contracts that are at the money at inception and whether this represents a significant uncertainty given the prevalence of strip pricing within the industry.

Onerous Performance Obligations

Under the proposal, entities may need to recognize a current-period loss to the extent that the present value of the expected direct costs of satisfying a separate performance obligation exceeds the amount of the transaction price allocated to that obligation. This may result in the immediate recognition of losses when a contract is underwater (which may be earlier than under current practice), such as with nonderivative commodity sales. The proposed guidance only affects the accounting treatment for the selling entity (i.e., the entity recognizing revenue) and does not change the accounting for the purchasing entity.

Financial Instruments Exposure Draft

In May 2010, the FASB issued a proposed ASU with the objective of giving financial statement users a more timely and representative depiction of an entity's involvement in financial instruments and reducing the complexity in accounting for financial instruments. The FASB expects to begin redeliberating the proposed ASU in the fourth quarter of 2010 and plans to issue a final ASU during the first half of 2011. The effective date of the requirements will be determined before the final standard is issued. The proposed ASU, *Accounting for Financial Instruments and Revisions to the Accounting for Derivative Instruments and Hedging Activities*, contains a comprehensive new model of accounting for financial assets and financial liabilities that addresses (1) recognition and measurement, (2) impairment, and (3) hedge accounting. The proposed ASU would affect the accounting for a broad range of financial instruments, including investments in debt and equity securities, investments in nonmarketable equity securities, loans, loan commitments, deposit liabilities, trade payables, trade receivables, derivative financial instruments, and debt liabilities. Certain financial instruments are exempt from the proposed standard, including (but not limited to) employee stock options, most insurance contracts, lease contracts, equity investments in consolidated subsidiaries, instruments classified in stockholders' equity, interest in a variable interest entity that the entity is required to consolidate, certain financial guarantee contracts, and obligations for pension or other retirement benefits.

Upon initial recognition, an entity would classify most types of financial instruments into one of the following principal categories:

- Fair value, with changes in fair value recognized in net income (FV-NI).
- Fair value, with certain changes in fair value recognized in other comprehensive income (FV-OCI).
- Amortized cost.

These classification categories would replace the current classification categories for financial instruments under U.S. GAAP, such as securities held for trading, available for sale, or held to maturity. Certain redeemable equity investments and core demand deposit liabilities will have separate categories.

The tables below summarize the proposed classification, measurement, and presentation of financial instruments. The default classification and measurement of financial instruments within the scope of the proposed ASU would be FV-NI. A financial instrument classified in this category is initially recorded at fair value and subsequently adjusted to fair value in each reporting period, with changes in fair value recognized in net income. Initial transaction costs and fees are recognized to net income immediately as incurred.

Classification	Criteria	Balance Sheet	Income Statement
FV-NI	Default classification of financial instruments.	Separate presentation on the face of the balance sheet: • Fair value. • For an entity's own outstanding debt classified as FV-NI, an entity would also be required to show amortized cost on the face of the balance sheet.	Separate line items within net income for: • Realized and unrealized gains and losses (in the aggregate). • Changes in fair value related to own credit standing (financial liabilities only). • No requirement to separately present interest accruals or credit losses.

However, the proposed ASU contains exceptions to the default classification and measurement guidance. An entity may elect to recognize and measure certain debt instruments at FV-OCI. The debt instruments are required to meet three criteria for classification as FV-OCI: (1) cash flow characteristics, (2) business strategy, and (3) the instrument cannot be a hybrid financial instrument containing an embedded derivative or derivatives that otherwise would have been required to be bifurcated.

For this category of financial instruments, the initial measurement generally is at the transaction price (exceptions apply), and the subsequent measurement is at fair value. Certain transaction costs and fees are deferred and recognized in earnings as yield adjustments over the life of the instrument (i.e., interest method).

<table>
<tr><th>Classification</th><th>Criteria</th><th>Balance Sheet</th><th>Income Statement</th></tr>
<tr><td>FV-OCI</td><td>An entity is permitted to measure a financial asset or financial liability at FV-OCI if it meets the following criteria:

Cash flow characteristics:
• An amount transferred to a debtor (issuer) at inception will be returned to the creditor (investor) at maturity or other settlement (principal).
• The contractual terms of the debt instrument identify any additional contractual cash flows to be paid to the creditor (investor) either periodically or at the end of the instrument’s term.
• 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.

Business strategy:
• The entity’s business strategy for the instrument is to collect or pay the related contractual cash flows rather than to sell the financial asset or settle the financial liability with a third party. The possibility that a debt instrument may be settled with the counterparty before the stated maturity date (i.e., the instrument may be prepaid) because of exercise of an embedded call or put option would not prevent an entity from having a business strategy to collect or pay the instrument’s contractual cash flows. Such an assessment is made at the portfolio level.

No embedded derivative:
• It is not a hybrid instrument for which the guidance on derivatives and hedging in ASC 815-15 would otherwise have required the embedded derivative to be accounted for separately from the host contract.</td><td>Separate presentation on the face of the balance sheet:
• Amortized cost.
• Cumulative credit losses.
• Adjustments to arrive at fair value.
• Fair value.</td><td>Separate line items within net income for:
• Interest income.
• Interest expense.
• Credit losses.
• Realized gains and losses.
• Foreign currency gains or losses would not be separated (they would be recognized in OCI).</td></tr>
</table>

An entity is permitted to classify short-term receivables and payables as amortized cost if they (1) arise in the normal course of business, (2) are due in customary terms not exceeding one year, (3) meet the FV-OCI classification criteria, and (4) are not short-term lending arrangements. In addition, an entity may measure certain financial liabilities other than core demand deposit liabilities at amortized cost if (1) the liability meets the FV-OCI criteria and (2) measuring the financial liability at fair value would create or exacerbate an accounting mismatch. An accounting mismatch may occur, for example, when the financial liability is contractually linked to an asset that is measured at amortized cost. Note that financial liabilities (other than core demand deposit liabilities) that do not qualify for amortized cost would be classified as FV-NI or FV-OCI (if the conditions discussed above are met).

Classification	Criteria	Balance Sheet	Income Statement
Amortized cost	Criteria applicable to measurement attribute mismatch (must meet at least one of the following criteria): • The financial liability is contractually linked to an asset not measured at fair value. • The financial liability is issued by and recorded in an operating segment for which less than 50 percent of the segment's recognized assets are subsequently measure at fair value. • The financial liability is the liability of a consolidated entity for which less than 50 percent of the consolidated recognized assets are subsequently measure at fair value.	Separate presentation on the face of the balance sheet: • Amortized cost.	Separate line item within net income for: • Interest expense (including amortization and accretions of premiums and discounts). • Realized gains and losses on settlement of liabilities.

Hybrid financial instruments that contain an embedded derivative that would otherwise require bifurcation are recognized and measured in their entirety at FV-NI, and the requirement to bifurcate the embedded feature from the host contract would be eliminated. The proposed ASU also would require that once the classification of the financial instrument is determined at initial recognition, it cannot be subsequently changed. This classification guidance would also apply to all trade payables and receivables with maturities greater than one year.

In addition, the proposed ASU would require a single approach to accounting for impairment for all financial assets in the FV-OCI category. Unlike current accounting requirements, the proposed ASU would have the same impairment requirements for loans, debt securities, and beneficial interests in securitized financial assets. In determining whether a credit loss exists, an entity would not consider a probability threshold; rather, the entity would consider all past and current events and existing conditions in assessing and calculating the amount of credit impairment. An entity would recognize a credit impairment when it expects there will be either a shortfall or delay in cash flows. In assessing credit impairments, an entity would consider remaining payment terms, the financial condition of the borrower or issuer, failure to make scheduled payments, expectations about potential default, credit ratings, and the value of any collateral. The entity would also consider existing environmental factors such as industry, economic, and political data. The entity would be required to assess credit impairment in each reporting period and to recognize the credit impairment in earnings. Other unrealized changes in the fair value of the instrument would be recognized in OCI. The proposed impairment model would also prescribe a revised approach for accruing interest income, which entities would calculate by applying the effective interest rate to the amortized cost of the financial asset reduced by any related allowance for credit impairment.

The proposed ASU establishes new criteria for determining whether an investment should be accounted for under the equity method of accounting, which will narrow the scope of accounting for equity method investments. An entity can only use the equity method if the investor has significant influence over the investee as described in ASC 323 and if the operations of the investee are considered related to the investor's consolidated operations. If such criteria are not met and the equity method of accounting is not applied, the investment will be reported at fair value, with changes in the value recognized as net income as described above.

The proposal would also amend the hedge accounting requirements in ASC 815. The changes proposed are consistent with the FASB's 2008 exposure draft on hedge accounting, except that the bifurcation-by-risk approach for financial hedged items in ASC 815 is retained. Some of the proposed ASU's significant changes to hedge accounting would include (1) elimination of the shortcut and critical-terms-match methods; (2) a change in the hedge effectiveness threshold necessary to qualify for hedge accounting from highly effective to reasonably effective; and (3) the inability to dedesignate a hedging relationship simply by removing the hedge designation, unless the criteria for hedge accounting are no longer met or the hedging instrument is sold, is terminated, expires, or is exercised. Under the proposed ASU, cash flow hedge ineffectiveness is measured by comparing the change in fair value of the actual hedging instrument with the present value of the cumulative change in expected future cash flows of the hedged transaction. The proposed guidance suggests that an entity could use a hypothetical derivative to measure the cumulative change in expected future cash flows of the hedged transaction, whereby such hypothetical derivative is priced at market, matures on the date of the hedged transaction, and exactly offsets the hedged cash flows. Unlike existing U.S. GAAP, the proposed ASU requires entities to record ineffectiveness for underhedges in earnings.

Subject	ASC 815	Proposed ASU
Items eligible for hedge accounting	Defined in ASC 815-20.	Same as ASC 815-20.
Risks eligible as hedged risks	Defined in ASC 815-20.	Same as ASC 815-20.
Amounts recorded as OCI for cash flow hedges	Represents the amount computed as the effective portion of the cash flow hedge.	Recorded as the amount necessary to offset the present value of the cumulative change in expected future cash flows on the hedged transaction since hedge inception.
Assumption that a hedge is perfectly effective	Shortcut and critical-terms-match methods, as defined in ASC 815.	Neither the shortcut method nor critical terms-match method is permitted.
Designating a hedging relationship	Hedge designation can be removed at the entity's discretion.	An entity cannot remove hedge designation after it has been established. The relationship can be discontinued only if certain criteria are met.
Threshold for hedge accounting	Highly effective.	Reasonably effective.
Means of assessing effectiveness	Both a quantitative and qualitative assessment of effectiveness is required.	Qualitative assessment is required at the inception of the hedging relationship; however, a quantitative assessment may be necessary in certain situations.
Frequency of hedge effectiveness assessments	The hedge effectiveness assessment is required at the inception of the hedging relationship and at each reporting period thereafter.	Hedge effectiveness is assessed at the inception of the hedging relationship only, unless a change in the circumstances warrants a reassessment.

Financial Statement Presentation Exposure Drafts

Rulemaking related to reporting of discontinued operations and OCI is expected in 2011. The FASB has issued an ED on OCI and expects to issue a final ASU in early 2011. In addition, it expects to issue an ED on reporting discontinued operations in the first quarter of 2011 and final ASUs late in 2011. In October 2010, the boards decided not to issue an ED on financial statement presentation in the first quarter of 2011, as they had planned. Instead, the boards expect to resume their financial statement presentation project in the second half of 2011.

As part of its financial statement presentation project, the FASB is investigating the manner in which financial information is presented in an entity's statement of financial position, statement of comprehensive income, and statement of cash flows. Existing standards allow for multiple presentation alternatives, which have caused inconsistencies in financial statement presentation and difficulties in understanding the relationship between an entity's financial statements and its financial results.

The revised guidance on financial statement presentation will be based on two core principles that state that information should be presented in the financial statements in a manner that:

- Results in a **cohesive** set of financial statements.
- **Disaggregates** financial information of an item on the basis of the item's function, nature, and measurement.

The proposed presentation format is expected to split financial information between business (i.e., operating and investing) and financing activities. The "business section" comprises the entity's assets and liabilities related to "day-to-day business functioning" and those that generate a return (i.e., investing). The "financing section" comprises the assets and liabilities related to an entity's obtaining or repaying capital and is further separated into debt and equity subcategories. Within each section or category, financial information would be further disaggregated by function, nature, and measurement on the basis of the type of disaggregation that provides the most relevant and useful information. This format would largely resemble the current presentation in the statement of cash flows under the indirect method. Under the proposed standard, a reporting entity will be required to present or disclose the following:

- *Statement of financial position* — The presentation of assets and liabilities by major activity within the operating, investing, and financing categories. Assets and liabilities would be presented together within a section and category.
- *Statement of comprehensive income* — A single statement of comprehensive income that classifies income and expense items consistently, with the classification of assets and liabilities giving rise to the income and expense. Further disaggregation by nature and function is also required, either in the entity's segment footnote or in the statement of comprehensive income if the entity reports as a single segment.
- *Statement of cash flows* — The separate presentation of the main categories of cash receipts and cash payments for operating activities (i.e., direct method) rather than reconciliation of net income to net operating cash flows (i.e., indirect method). In addition, a reconciliation of operating income to net operating cash flows would be required in the statement of cash flows.
- *Notes to the financial statements* — Disclosure of the rationale used to classify assets and liabilities into categories and sections in the statement of financial position. In addition, an entity would be required to provide a reconciliation of beginning to ending balances of select assets and liabilities that management deems important to an understanding the entity's financial position.

As proposed, financial statements would be presented as follows:

Statement of Financial Position	Statement of Comprehensive Income	Statement of Cash Flows

Business section
• Operating category
  o Operating finance subcategory
• Investing category
	Business section
	• Operating category
	  o Operating finance subcategory
	• Investing category
		Business section
		• Operating category
		• Investing category

Financing section • Debt category • Equity category	**Financing section** • Debt category	**Financing section**
	Multi-category transaction section	**Multi-category transaction section**
Income tax section	**Income tax section**	**Income tax section**
Discontinued operations section	**Discontinued operations, net of tax, section**	**Discontinued operations section**
	OCI, net of tax	

Discontinued Operations

The FASB is proposing to redefine what constitutes a discontinued operation as well as to modify the disclosure requirements. Under the proposed guidance, a discontinued operation would be either of the following:

- A component of an entity that either has been disposed of or is classified as held for sale and that represents (or is part of a single coordinated plan to dispose of) a separate major line of business or geographical area of operations.
- A business that, on acquisition, meets the criteria for classification as held for sale.

The FASB expects the proposed guidance to result in fewer disposals that meet the criteria for classification as a discontinued operation on the face of the statement of comprehensive income. Therefore, to address concerns about the loss of information, the proposed guidance also includes expanded disclosure requirements both for discontinued operations and for significant components disposed of, or to be disposed of, that do not meet the revised criteria for classification as a discontinued operation. In addition, for disposals of long-lived assets that are not components of an entity, the entity is required to disclose those classes of assets and liabilities in the notes to the financial statements and reconcile the amounts provided in the notes to total assets and liabilities classified as held for sale shown separately in the financial statements. Finally, expanded disclosures are required for entities that have continuing involvement or continuing cash flows with the discontinued operations.

The proposed guidance would also align the scope of ASC 205-20 with that of IFRS 5 to apply to all recognized noncurrent assets and to all disposal groups of an entity. Currently, ASC 205-20 excludes certain assets, including (but not limited to) financial instruments (including equity method investments), deferred tax assets, certain oil and gas properties, and other long-lived assets for which the accounting is prescribed in ASC 980 (i.e., abandonments and disallowances of plant costs for regulated entities). The FASB expects the changes in scope to have a limited impact on entities, except that it would require an entity to consider whether the disposal of an equity method investment should be reported and disclosed as a discontinued operation, which could now qualify as a discontinued operation.

Other Comprehensive Income

Under the proposed ASU *Comprehensive Income*, an entity would be required to report total comprehensive income and its components in two parts — net income and OCI — in a continuous financial statement. This proposed standard eliminates the choices under current U.S. GAAP in ASC 220-10-45-8, which permits three presentation alternatives for displaying OCI and its components in the financial statements:

- Below the components of net income in a statement of comprehensive income.
- In a separate statement of OCI that begins with total net income.
- In a statement of changes in equity.

The proposed ASU would not change the items that must be reported in OCI, or change the option to show components of comprehensive income net of income taxes, as long as the income tax effects for each component are shown in the notes or on the face of the statement. The calculation of earnings per share would also not be affected.

In the disclosure of accumulated OCI, all accumulated balances for each component of comprehensive income in the component of equity are disclosed only in the statement of changes in equity or notes to the financial statement.

Proposed ASU, *Contingencies*

The FASB issued a proposed ASU, *Contingencies*, in response to concerns by users of financial statements that entities had not been providing sufficient disclosure on loss contingencies. The proposal updates the ED on contingencies issued by the FASB in 2008. The proposed ASU would require more detailed information about the likelihood, timing, and magnitude of the impact of loss contingencies on cash flows of the entity.

The proposed ASU applies to all loss contingencies under ASC 450-20 and ASC 805, including environmental obligations, potential insurance expenses related to changes from occurrence-based insurance to claims-made insurance, and other contingencies described in the table below. The increased disclosure requirements related to environmental obligations are a significant change from previous U.S. GAAP, particularly for the energy industry.

New Disclosure Requirements

The proposed ASU would expand the scope of disclosures that entities provide by (1) lowering the threshold for required disclosure to include certain remote contingencies, (2) increasing the amount of qualitative and quantitative disclosure, and (3) requiring public companies to provide a tabular disclosure. This change applies to all contingencies for which ASC 450 and ASC 805 require disclosures, not only litigation contingencies.

According to the proposed ASU, an entity's disclosure of loss contingencies should include both "qualitative and quantitative information . . . to enable financial statement users to understand all of the following:

a. The nature of the loss contingencies

b. Their potential magnitude

c. Their potential timing (if known)."

While the proposed ASU does not change the requirement to record loss contingencies that are probable or to disclose loss contingencies that are reasonably possible, it does require disclosure of certain remote contingencies. For contingencies that are considered remote, an entity would need to assess whether it is vulnerable to a potential severe impact that could result from the contingency. When assessing whether the impact has the potential to be severe, the entity should consider the potential magnitude of the claim, costs to defend the entity's position, and the amount of time and resources allocated to resolving the matter.

Qualitative Disclosure

For all contingencies that meet the threshold for disclosure, an entity will be required to disclose the following information:

- Information about the nature and risks of the loss contingency.
- For individually material contingencies, sufficiently detailed information, provided separately, about the contingency.
- The basis for aggregation of loss contingencies (see discussion of aggregation below).

The proposed ASU allows disclosure of similar loss contingencies to be grouped together. The entity would use judgment in determining which contingencies are aggregated on the basis of their nature, terms, and characteristics. For aggregated loss contingencies of a large amount of similar claims, an entity may disclose the total number of claims, the average amount claimed, and the average settlement amount.

For asserted litigation contingencies, an entity would also disclose information about the claim of the parties, including the amounts claimed, position of the entity, etc. As more information about the claim becomes available, the disclosure should become more robust, specifically if an unfavorable outcome becomes apparent. If they are known, an entity should also disclose the next steps in the proceedings or anticipated timing.

Quantitative Disclosure

Entities with loss contingencies that meet the threshold for disclosure would disclose the following quantitative information:

- Information available to the public.
- Any nonprivileged information that would be useful to users of the financial statements.
- Information about potential recoveries from insurance or third parties, only if that information has been "provided to the plaintiff(s) in a litigation contingency, it is discoverable by either the plaintiff or a regulatory agency, or it relates to a recognized receivable." An entity must also disclose whether an insurance company contests, denies, or reserves its rights related to the claim.[7]

Further, if the loss contingency is at least reasonably possible, the entity must also disclose the possible loss or range of loss. If such amount cannot be estimated by the entity, the entity must so state and disclose the reason why.

[7] Any recognized recoveries from insurance or third parties should not be netted against the loss contingency. Rather, they should be shown as a separate line item within the statement of financial position.

Tabular Reconciliation

The proposed ASU would significantly change current guidance by requiring public companies to provide a tabular disclosure, for each annual and interim period for which an income statement is presented, of loss contingencies by class (dissimilar contingencies may not be aggregated). The tabular disclosure should include (1) the beginning and ending accrual amounts, (2) any accrual for new contingencies during the period, (3) increases for changes in estimates of loss contingencies recognized in prior periods, (4) decreases for changes in estimates of loss contingencies recognized in prior periods, and (5) decreases for cash payments or settlements during the period. Loss contingencies acquired in a business combination should be shown separately if they have a different measurement attribute (i.e., such as fair value).

In addition to the table, entities must describe the significant activity (i.e., increases or decreases for a change in the estimate, decreases for settlements, increases for new loss contingencies recognized) in the contingencies and disclose the line item within the statement of financial position on which the contingencies are recorded. Loss contingencies that arise and are settled within the same period do not need to be included in the table.

Prejudicial Exemption

The 2008 ED contained a limited exemption that allowed entities to not include information about the contingencies that could be prejudicial because of pending or threatened litigation. The proposed ASU, however, does not include that exemption because the FASB believes that any of the speculative or predictive disclosure requirements in the 2008 ED have been eliminated in the proposed ASU.

Effective Date and Transition

In October 2010, the FASB announced that the proposed effective date in the ASU would be revised. However, the FASB will not determine a new proposed effective date until after its review of comments received on the proposed ASU. Comparative disclosures will not be required in the period of adoption. Early adoption is permitted.

Amendments to the Codification

The following Codification subtopics would be substantially amended as a result of the ASU.[8]

Codification Subtopic	Description of Amendment
450-20, *Contingencies: Loss Contingencies*	Guidance on disclosure of certain loss contingencies would be amended.
410-30, *Asset Retirement and Environmental Obligations: Environmental Obligations*	Disclosure related to loss contingencies on environmental obligations would be expanded to include the disclosures in the proposed ASU.
460-10, *Guarantees: Overall*	Disclosures of loss contingencies related to guarantees (other than product warranties) would be removed from ASC 450-20-50. ASC 450-20-50 would be clarified to include product warranties.
715-80, *Compensation — Retirement Benefits: Multiemployer Plans*	The disclosure threshold for withdrawals from a multiemployer plan would be expanded to include withdrawals that may give rise to certain loss contingencies that meet the threshold for disclosure in this proposed ASU.
805-20, *Business Combinations: Identifiable Assets and Liabilities, and Any Noncontrolling Interest*	Required disclosures of loss contingencies as they arise from business combinations would be expanded to include the disclosures in this proposed ASU.

[8] As adapted from the proposed ASU *Contingencies*.

Proposed ASU, *Going Concern*

The FASB expects to issue an exposure draft of a proposed ASU related to going concern. This proposed ASU would address (1) management's responsibility to evaluate a reporting entity's ability to meet its obligations for the foreseeable future and (2) the application of the liquidation basis of accounting.

The proposal would require disclosures when management, applying commercially reasonable business judgment, is aware of conditions and events indicating that it is reasonably foreseeable that an entity may not be able to meet its obligations as they become due without making substantial changes to its operating or capital structure. These changes could include, but would not be limited to, a substantial disposition of assets outside the ordinary course of business, restructuring of debt, issuance of equity, or externally or internally forced revisions of its operations. The proposed ASU would require that management take into account available information about the foreseeable future, which is generally, but not limited to, 12 months from the end of the reporting period.

The proposed ASU would require an entity to use the liquidation basis of accounting to prepare its financial statements when liquidation appears imminent. Liquidation is imminent if (1) a plan of liquidation has been approved or (2) the plan to liquidate is being imposed by other forces and it is remote that the entity will continue in operation. Under the proposed ASU, an entity would be required to measure financial statement items to reflect the amount of cash it expects to collect or pay during the course of liquidation.

Multiemployer Benefit Plan Disclosures Exposure Draft

Overview

At the beginning of September 2010, the FASB issued a proposed ASU, *Disclosure About an Employer's Participation in a Multiemployer Plan*, that would increase the level of quantitative and qualitative disclosures an employer would be required to make about its participation in multiemployer benefit plans. Note that the proposed disclosures would **not** apply to an employer's participation in multiple-employer plans (e.g., single-employer plans aggregated to pool plan assets for investment purposes or to reduce the costs of plan administration). The Codification's Master Glossary defines a multiemployer plan as follows:

> A pension or postretirement benefit plan to which two or more unrelated employers contribute, usually pursuant to one or more collective-bargaining agreements. A characteristic of multiemployer plans is that assets contributed by one participating employer may be used to provide benefits to employees of other participating employers since assets contributed by an employer are not segregated in a separate account or restricted to provide benefits only to employees of that employer. A multiemployer plan is usually administered by a board of trustees composed of management and labor representatives and may also be referred to as a joint trust or union plan. Generally, many employers participate in a multi-employer plan, and an employer may participate in more than one plan. The employers participating in multiemployer plans usually have a common industry bond, but for some plans the employers are in different industries and the labor union may be their only common bond. Some multiemployer plans do not involve a union. For example, local chapters of a not-for-profit entity (NFP) may participate in a plan established by the related national organization.

Disaggregation of Multiemployer Plans

The proposed ASU requires separate disclosures for pension plans and other postretirement plans. Narrative information for these two categories of defined benefit plans would then be further disaggregated "for plans or groups of plans with significantly different risk characteristics or contractual commitments [and the] basis for disaggregation shall be disclosed." Quantitative information may also need to be disclosed for an entity's multiemployer plans, individually or in the aggregate, depending on the materiality of the plans. The proposed ASU requires separate quantitative disclosure for plans that are individually material. For plans that are not individually material but are material in the aggregate, quantitative information can be provided in the form of a range that covers the population aggregated. The proposed ASU requires that quantitative information be "provided for each annual period for which a statement of income or statement of financial position is presented."

Nature of the New Disclosure Requirements

Current disclosure requirements of multiemployer benefit plans primarily focus on an employer's annual contributions to multiemployer plans; however, they do not give users of financial statements the information they need to assess an employer's risks and commitments associated with its participation in a multiemployer plan. To address this, the proposed ASU requires employers to disclose:

a. Information about the multiemployer plan

b. Information about the employer's participation in the plan

c. Information about cash flow implications arising from the employer's participation in a multi-employer plan.

If an employer is not able to provide the required disclosures, the employer must disclose why it could not obtain the information.

Effective Date and Transition

In the second quarter of 2011, the FASB expects to issue a final standard with a different effective date from that in the proposed ASU. Comparative disclosures would be required prospectively only.

Section 8
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 of a conversion from U.S. GAAP to IFRSs.

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.

The Patient Protection and Affordable Care Act and the related Health Care and Education Reconciliation Act of 2010 amended the IRC to eliminate the tax deduction for the portion of the prescription drug costs for which an employer receives a Medicare Part D federal 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 with other costs for which rate recovery is sought, regulatory actions involving other utilities in a given jurisdiction may provide an indication of the likelihood of rate recovery 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/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

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 that 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. The taxpayer's regulatory personnel were not familiar with the normalization requirements and did not realize that the two fields were alternatives. The taxpayer inadvertently populated the template filing in both fields, which reduced the rate base and cost of service. Rates were approved without detection of the template population error by 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 to not 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.

Extension and Enhancement of Alternative Energy Incentives Under the American Recovery and Reinvestment Act of 2009

The ARRA contains a number of provisions that extend or modify existing renewable energy incentives and includes several new incentives as well.

Under the ARRA, the PTC under IRC Section 45 is extended for three years for most qualifying resources. For wind projects, facilities must be placed in service by December 31, 2012. For other qualifying projects, such as biomass, geothermal electricity, landfill gas, trash, hydropower, marine, and hydrokinetic, facilities must be placed in service by December 31, 2013. The PTC is generally a 10-year credit, based on the amount of electricity generated and sold to unrelated parties.

In addition, under the ARRA, taxpayers with facilities that would otherwise be eligible for the PTC under IRC Section 45, such as wind or biomass facilities, have the ability to elect the 30 percent ITC under IRC Section 48 in lieu of the PTC. The election is available with respect to any facility that has not previously been allowed a credit under IRC Section 45 and is irrevocable. The property to which the election applies must be tangible personal property or other tangible property used as an integral part of the facility. The

ITC is a one-time credit based on the amount of investment in energy property, subject to recapture for a five-year period after the property is placed in service. Generally, the energy property must be placed in service by December 31, 2016. As provided under the Emergency Economic Stabilization Act of 2008, effective February 13, 2008, public utility property is eligible for the energy credit, and the accounting for the energy credit by rate-regulated utilities is subject to the normalization requirements.

In addition, the ARRA removes the current ITC reduction under IRC Section 48 for subsidized energy financing provided after December 31, 2008, by federal, state, or local programs. Under prior law, the basis on which the ITC was calculated was reduced for the value of subsidized energy financing received by the taxpayer to support constructing the credit-qualifying facility.

The ARRA authorizes the Treasury department to provide grants in lieu of tax credits (Treasury grants) for property placed in service in 2009 or 2010 (or placed in service after 2010 and before the credit would otherwise terminate, if construction began in 2009 or 2010) that is otherwise eligible for the PTC under IRC Section 45 or the ITC under IRC Section 48. No credits will be determined under IRC Sections 45 or 48 with respect to any property that receives a Treasury grant.

The Treasury grant amount is 30 percent of the cost of wind facilities, closed-loop biomass facilities, open-loop biomass facilities, geothermal electricity production facilities, landfill gas facilities, trash facilities, hydropower facilities, marine/hydrokinetic facilities, fuel cell property, solar property, and small wind property. The Treasury grant amount is 10 percent for geothermal energy property, qualified microturbine property, and combined heat and power property.

Generally, the rules that apply under IRC Section 48 apply to the Treasury grants. Although the rules pertaining to Treasury grants are more flexible than the rules that apply to ITC with respect to recapture, they are more restrictive regarding investments by tax-exempt investors. Under Treasury grant guidance, like the ITC rules, recapture occurs if cessation of use of the property occurs within the five-year period after the placed-in-service date. However, under Treasury grant guidance, recapture only applies to a nonqualified recipient or cessation of use of the property in the generation of electricity. Also, under Treasury grant guidance, like the ITC rules, federal, state, or local governments; exempt organizations under IRC Section 501(c); and entities subject to IRC Section 54(j)(4), such as a clean renewable energy bond lender, are not eligible to receive the Treasury grant. Under the ITC rules, tax-exempt investors are not allowed ITC, and their ownership of a partnership investing in qualifying property reduces the amount of ITC that may be claimed with respect to property owned by the partnership. However, under Treasury grant rules, any partnership or other flow-through entity with any partner that is an organization or entity described herein can receive a Treasury grant without reduction to reflect the investment by the tax-exempt partner if such partner owns its interest in the applicant through a taxable Subchapter C corporation.

Treasury grants are provided within 60 days of receipt of a complete application. All applications are due no later than October 1, 2011. If property is placed in service during 2009 or 2010, the application may only be submitted after the property is placed in service and before October 1, 2011. For property placed in service after 2010, but for which construction began in 2009 or 2010, the initial application may only be submitted after construction commences and must be filed before October 1, 2011. The Treasury department issued detailed guidance in 2010 on determining when construction begins for Treasury grant eligibility.

Accounting for Treasury grants, ITCs, and PTCs is discussed in Section 10.

Section 9
An Overview of the Smart Grid Business Case

Customer Education and Adoption Are Required to Realize Benefits

Other than during a few major worldwide events, including the oil crisis of the 1970s, energy has been fairly cheap because most electricity production was and is based on crude oil, natural gas, and coal as fuel sources. For the better part of the 20th century, industrialized countries consistently absorbed fuel supplies to power their economies to unprecedented levels of productivity and prosperity. Sovereign countries once considered third world are now quickly developing into manufacturing powerhouses with populations significantly larger than many industrialized countries put together and with economies growing at double-digit rates and standards of living significantly on the rise. Although per capita electricity consumption is highest in the United States, growing economies are responsible for higher acquisition rates of generation fuel sources and significant carbon emissions.

Participants across the spectrum of the domestic energy value chain are faced with multiple challenges to generate and deliver energy to end-use consumers. Generators, utilities, energy service providers, and retailers alike understand the simple truth that the increased worldwide demand for power is driving up costs for fuel sources used to generate electricity. Rising generation costs ultimately find their way to consumers in the form of rising rates and consumption charges. Relative inefficiencies associated with operational processes add to a rising cost basis and, at a minimum, do not provide any support in terms of cost relief. Throw in regulatory legislation related to renewable portfolio standards and clean energy requirements, as well as renewable integration limitations, and energy companies are observing cost curves whose slopes are rising more quickly than ever seen before.

Costs will continue to rise. Only through the application of advanced technologies, streamlined processes, productivity improvements, and active customer participation will regulated utilities be able to contain rising overall costs and retain capabilities to effectively and efficiently serve their constituents.

An Intelligent Grid

In principle, the smart grid is an upgrade of the existing power grid that's characterized by the application of sensing, control, and measurement technologies linked together in a ubiquitous fashion employing two-way communications, granular data collection and visibility, and informed decision making. Rather than simply broadcast power from centralized power generators to a large number of users, an intelligent grid should support the routing of power in more optimal ways to respond to a very wide range of conditions, automatically resolve power outages and power quality issues, and align the true cost of supply with demand throughout the day. Information about consumption and demand, pricing, and grid conditions can be used by consumers, grid operators, and control systems to allow them to plan for and respond to changing conditions and to integrate distributed generation sources located closer to load centers. Although smart meters have taken center stage in many smart grid discussions, the smart grid is much more comprehensive and includes substation automation, transmission applications, distributed generation, energy storage, and renewable integration.

The Smart Grid Business Case

Any investment opportunity, whether personal or business related, should be supported by a business case. Although different methods of evaluation criteria for competing alternatives may be used, including net present value, return on investment, payback period, and hurdle rates, the goal is the same — to pick among the alternatives that provide the greatest return on invested dollars. Many critics of smart grid investments, and of smart metering in particular, focus on and espouse that most benefits are attributable to the utility and not to the consumer. The perception is that consumers are simply paying for investments that ultimately only help the utility. Consumer benefits are indeed possible and, in fact, could be significant. It's important for consumers to take a participative role in energy management programs and to modify energy consumption behaviors to fully realize smart grid business benefits and curb rising costs.

It should also be recognized that regulatory oversight made possible through the ratemaking process is designed to prevent indiscriminate investments by a utility that simply raise a utility's cost basis, thus leading to rising rates. The basic objective of utility ratemaking is to determine the total amount of revenues a company must generate from its operations to achieve its own objectives, a fair return, and to meet the needs and objectives of its customers. Regulators attempt to obtain for the public both the benefits that would be achieved by competition and the efficiency of operation as a monopoly. In most cases, operational improvements due to smart metering investments are, in fact, benefits to both the utility and the customer. Smart metering investments that lower utility cost structures, improve productivity measures, and lower overhead certainly improve a utility's financial performance. Through the ratemaking process, however, many state regulatory commissions will pass on these cost savings to ratepayers through lowered rates as the utility's cost basis is reduced. A few investor-owned utilities recently documented significant smart metering investments without a request to raise customer rates because the investments were mitigated by operational cost savings.

Smart Grid Business-Case Benefits

Five primary categories of benefits realization for smart grid investments include:

- Operational efficiency.
- Grid automation.
- Financial risk and peak load reduction.
- Regulatory compliance.
- Customer service and revenue enhancement.

Operational Efficiency and Grid Automation

Properly managed and implemented smart metering initiatives provide numerous opportunities to reduce cost structures, improve productivity, and streamline operations. These initiatives include, but are not limited to, the following.

- Networked, remote meter reading supports:
    - Reductions in requirements for manual meter reading.
    - Reduction in vehicle costs, maintenance expenses, insurance, and overhead.
    - Elimination of property access and safety issues.
- Reduced field trips assist in response-time improvement for critical events and better allocation of limited resources.
- Remote connect, disconnect, and configuration capabilities reduce aggregate field trips.
- Power outage sensing and reporting preempts the need for customers to identify outages and focuses repair activities more discretely.

- Volt/ampere reactive sensing capability protects critical machinery and customer business operations.
- Fault detection and isolation improves reliability performance metrics (e.g., system average interruption frequency index, customer average interruption duration index).
- Critical assets can be managed more effectively (e.g., transformers) through near-real-time asset loading analysis.

Financial Risk, Peak Load Reduction, and Regulatory Compliance

- Intraday consumption and collection of interval data enables:
    - Time-of-use pricing and public utility compliance.
    - A shifting of financial risk to consumers.
    - Improved margins by tying prices to actual power generation and purchasing costs.
    - Customer segmentation based on detailed consumption patterns.
- Direct load control helps to modulate loads during critical demand periods and:
    - Reduces consumption and increases network reliability.
    - Reduces the need for peaking power generation and spot market reliance characterized by higher costs.
    - Supports reductions or deferrals of additional future plant investment.
- "Price-responsive demand response" enables customers to respond to dynamic prices and shift loads to less expensive periods of supply.
- Networked meter reading increases billing accuracy and reduces estimated bills.

Customer Service and Revenue Enhancement

- Automated fault detection and restoration reduces revenue loss associated with system downtime.
- Consumption monitoring supported by alarms and automated workflow can stem revenue loss associated with theft and unbilled energy.
- Remote connect and disconnect capability increases customer satisfaction through reduced service activation time and requirements to be onsite for triage of potential service delivery issues.
- Net metering facilitates the ability to integrate distributed generation sources and provides the ability for customers to sell back excess generation.
- Incorporation of excess distributed generation reduces utility exposure to high costs of peak generation and helps to maintain grid stability.
- Consumption presentment facilitates customer understanding and decision making with regard to usage patterns and load shaping impact.

- Future services for appliance monitoring and automated workflow for repair activities become realistic.
- Energy forecasting processes may no longer need to rely on load profiles because granular consumption data can be identified without the need for class-level aggregation and disaggregation of monthly consumption.
- Cash flow recognition is improved through implementation of prepay services and shorter meter reading/billing invoicing capability.

Customer Adoption and the Smart Grid Business Case

Smart metering alone can yield certain cost savings through various process improvements, and most regulated utilities will eventually share these savings with end-use customers through future tariff reductions. But other critical assumptions regarding customer adoption and penetration to implement critical load management and effective rate structures are firmly linked to load shaping and energy management activities that require active customer participation.

Building a smart grid means creating a smart customer, which requires (1) providing more timely and more accurate pricing information, including both historical and real time consumption data, and (2) obtaining more informed decision making by customers — which won't come about until they understand the implications of their actions (and inactions), both individually and in concert with other similarly motivated customers. The utility has an obligation to make consumption information available to facilitate customer decision making and to drive customer interest, adoption, and required behaviors. But customers also must learn how to use new energy management tools, interpret data, participate in energy conservation and load-shaping and -shifting activities, and understand the value that AMI can bring. Without this customer education and engagement, the envisioned end-state benefits will be impossible to achieve. With the significance of the changes introduced, customer education must begin before the new functionality is available to them — up-front, proactive engagement of the customer early in the project will help ensure that once the system is deployed the customers are both prepared and excited for what is available to assist them in their personal energy management.

In the case of smart metering, educating customers isn't simply about letting them know that a new meter will become part of their premises; it doesn't only take the form of a bill insert with attractive graphics; it shouldn't include only an e-mail or letter that explains new functionality that is available on a Web site. Consumers need to understand how energy is procured, what they pay for each month (i.e., beyond commodity charges), and what regulators are requiring of utilities. And perhaps they need personalized attention, to the extent possible, to bring them on board. Action is required on both sides of the equation — the customer has a role to play, and utilities must help consumers make the transition from passive purchasers to informed decision makers. The entire relationship between the utility and its customer base must be reengineered.

For further information about customer adoption issues and potential smart metering operational improvements, refer to the following publications:

- *"Bringing Customers on Board (Part 1), Realizing the Benefits of Smart Meters"* — An analysis of customer adoption issues, challenges, and recommendations for the utility planning to implement AMI and smart metering capabilities.

- *"Bringing Customers on Board (Part 2), The Entire Utility-Consumer Relationship Must Be Reengineered"* — Picking up where the first article left off, this article briefly covers customer adoption issues and challenges and provides five distinct recommendations for the utility implementing AMI and smart metering capabilities to jump start field pilot programs focusing on novel ways to engage customers and utility benefactors.

- *"Smart Forecasting for a Smarter Grid"* — An exploration of the challenges and opportunities associated with how the availability of detailed consumption data made available through AMI can affect business transaction execution involving load forecasting and load profiling activities. The article discusses the possibility of using aggregated interval data to replace load profiles to support energy procurement, asset management, and market settlement operations.

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, Treasury grants, and other economic incentives. Tax incentives that are expected to affect the P&U sector that are available under the ARRA are further discussed in Section 8.

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 PTCs under IRC Section 45 for wind resource generation facilities through December 31, 2012, and for certain other renewable generation facilities through December 31, 2013. To calculate PTCs, stated rates (e.g., 2010 wind production at 2.1 cents) are 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). To calculate ITCs, stated rates (e.g., 30 percent for wind and solar electric generation property) are 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 ("Treasury grant") for renewable generation property, including public utility property, on which construction begins by December 31, 2010, 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). Property on which construction begins after December 31, 2010, will not be eligible for Treasury grants but will still be eligible for ITC if placed in service before the applicable ITC expiration date. A key difference between ITC and Treasury grants, and a primary reason for enactment of the Treasury grants, is that the Treasury grants are not subject to the limitations that apply to ITC on the basis of tax liability or tentative minimum tax. Treasury grants are similar to ITC in other respects (e.g., recapture and public utility property ITC normalization provisions). Partnerships and LLCs treated as pass-through (nontaxable) entities are eligible for Treasury 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 Treasury grant applications must be submitted before October 1, 2011 (even though the property may be placed in service later). Final applications for qualified properties with an eligible cost basis of $500,000 or more must be accompanied by some form of an independent accountants' certification. Treasury grants are to be paid to taxpayers 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

In March and June 2010, the Treasury issued updated program guidance and frequently asked questions (FAQs), respectively, to clarify certain provisions of the program guidance. The FAQs are aimed at clarifying eligibility requirements for properties placed in service after December 31, 2010, as a result of meeting the beginning-of-construction criterion (i.e., the construction of such properties must begin in 2009 or 2010).

Significant provisions from the FAQs are summarized below:

- For projects placed in service after December 31, 2010, to be considered grant-eligible, "physical work of a significant nature" must be completed in 2009 or 2010 (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 requirement for physical work of a significant nature. 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 as physical work of a significant nature. Also, applicants relying on the binding contract provision to satisfy the requirement for physical work of a significant nature must demonstrate that the binding contract was enforceable **and** that the assets under contract are distinguishable from other assets in production, or held in inventory, by the counterparty before December 31, 2010.

- 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 and 2010 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, 2010, 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, 2010, 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 during 2009 and 2010. If costs 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.

- 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, 2010, 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 the determination of whether an applicant has undertaken a continuous program of construction.

- Applicants seeking eligibility to receive Treasury 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, 2010, must file an initial application with Treasury before October 1, 2011, to demonstrate that "physical work of a significant nature" has commenced, or that costs paid or incurred before December 31, 2010, 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 independent accountants. However, the FAQs do not elaborate on the form of such certification. (Note that as of this writing, a working group, consisting of representatives from the AICPA and certain of the large accounting firms, has met with Treasury to develop a model form for the report to be issued by the independent accountant and submitted with the initial grant application on or before October 1, 2011, if the 5 percent safe harbor is elected.)

The program guidance and FAQs are available on the Treasury department's Web site.

Accounting for PTCs

When an entity claims PTCs (instead of ITC or Treasury 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 Treasury Grants

Treasury grants should be accounted for as a grant and not as a tax credit. ITC eligible for Treasury 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 Treasury grant (e.g., ITC related to construction that began after 2010) would be subject to the accounting under ASC 740-10.

There is a view that Treasury grants would be elected in lieu of ITC when such election is available because generally there would be no economic disadvantage to such election. However, in certain circumstances there may be state income tax or other economic disadvantages to electing the Treasury grants in lieu of ITC. For example, Treasury 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. To the extent that ITC is claimed instead of the Treasury grants because the Treasury 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. The determination of what constitutes "less economically favorable" should be made on a case-by-case basis and should take into account all available facts. If an entity elects a Treasury grant after initially claiming ITC, the initial ITC accounting should be converted to grant accounting at the time the ITC is recaptured and converted to a Treasury grant.

When ITC eligible for Treasury grants and the Treasury 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 shall 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 Treasury 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 ASC 740-10-55-203 and 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 Treasury grants are subject to the ITC normalization requirements. As a result, depending on the normalization election made, the regulated entities must assure that the unamortized grant amount netted against property 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. Consideration should also be given to the treatment of the deferred tax amounts related to the book/tax basis differences noted above to ensure that they do not result in a normalization violation.

Grant Eligible ITC Claimed on QPEs

ITC claimed during the construction period for property that is eligible for the Treasury grant should be deferred until the property is placed in service because it is presumed that such Treasury 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.

Treasury Grants on Property Owned by Partnerships and LLCs

Treasury grants received by both nontaxable and taxable partnerships and LLCs require accounting recognition 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 Treasury 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.

Start-Up Versus Development Costs and Timing of Capitalization

Fundamental to renewable energy developers' business activities is the development of renewable energy generation facilities (individually, a project). A typical project undergoes three stages of development: start up, development (ordinarily, construction phase to reaching commercial operation), and late-stage development (postcommercial operation). As further discussed below, certain milestones must be met before an entity's decision to construct a project.

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

ASC 720-15-20 requires that start-up costs be expensed as incurred, and it broadly defines start-up costs as "those one-time activities related to any of the following":

a. Opening a new facility

b. Introducing a new product or service

c. Conducting business in a new territory

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

e. Initiating a new process in an existing facility

f. Commencing some new operation.

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

Development costs are costs incurred before the initiation of an acquisition or construction of a project but after the decision to initiate such transaction has been made. In general, development costs are capitalizable as long as they relate to a specific project and if an entity's management concludes that construction and completion of such project is probable. The conclusion about probability should be based on the achievements of milestones or a combination of milestones and on an entity's historical experience, such as receipt of permits or approvals from governmental agencies, execution of power purchase agreements, and execution of agreements to acquire significant project components. Examples of potentially capitalizable development costs include project acquisition fees, costs to obtain permits and licenses, professional fees, and internal costs related to contract negotiation.

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

Certain late-stage development activities are likely to continue to take place after a project reaches commercial operation and may last up to two years postcommercial operation. Costs associated with late-stage development generally relate to employee training to operate and maintain the project, equipment fine tuning, as well as contract negotiation related to project operation. These costs are generally not capitalizable.

The determination of whether a cost exhibits characteristics of a start-up cost as opposed to a development cost is a matter of judgment based on the relevant facts and circumstances. Certain costs may appear to relate to a specific project; however, their incurrence may not be necessary to construct or to reach commercial operation for a project. These costs should not be capitalized as part of project costs. Examples include, but are not limited to, power market studies not related to the construction of a specific project, professional fees related to accounting and tax services, legal fees associated with the execution of a power purchase agreement, and administrative/corporate overhead allocation.

Certain circumstances throughout the development stages may raise doubts about whether any or all of the capitalized project costs would be recoverable. Examples of such circumstances can be found in ASC 360-10-35-21. Entities should look to the guidance in ASC 360-10 in determining whether capitalized project costs are impaired and thus warrant an immediate write-off. To test for recoverability, an entity should compare future cash flows from the use and ultimate disposal of the project (i.e., cash inflows to be generated by the project less cash outflows necessary to obtain the inflows) with the carrying amount of the project (i.e., year-to-date capitalized project costs plus estimated costs to complete construction and reach commercial operation). Impairment exists when the expected future nominal (undiscounted) cash flows excluding interest charges are less than the project's carrying amount.

Entities should develop a capitalization policy in accordance with the above guidance and apply such policy consistently to all of their projects. Best practice for capitalization policy incorporates entity-specific considerations, including factors affecting management's judgment to determine the proper accounting of start-up and development costs. At a minimum, entities should consider incorporating the following in their capitalization policy:

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

Revenue Recognition Issues

Although recognizing revenue from a renewable contract may not be as complex when compared with recognizing it from contracts in the high-tech or biotech industries, entities face some revenue recognition challenges when executing a renewable energy contract and recording its related revenues. Those challenges include separating the contract into its unit or units of accounting, individually accounting for those units, and applying special revenue recognition rules for long-term power contracts.

Unit of Accounting

Under certain renewable energy contracts, two underlying products are delivered to a single customer. Those products often include (1) power generated from a renewable energy facility and (2) the renewable energy certificates or credits (RECs) granted from a regulatory body for the generation of power by the renewable energy facility. The pricing for these arrangements may be bundled, but more often than not separate pricing is used. In addition, these multiple-product arrangements are generally unlike fossil fuel power sales contracts, which typically consist of one product being delivered to a customer (e.g., power generated from the fossil facility).

When dealing with these multiple-product arrangements, entities should evaluate the combined arrangement in their assessment of the unit of accounting. Practice in this area is diverse, possibly because in the past, the most prevalent contracts were fossil fuel or nuclear contracts that only resulted in the delivery of one product. Because of significant growth in the number of renewable energy facilities across the world, entities have been begun reevaluating whether historical accounting policies used to account for single-product arrangements are adequate to use to account for multiple-product arrangements.

Historically, many entities have followed a two-step approach to evaluate these arrangements. An entity would first evaluate them under ASC 840 to determine whether the contract was a lease or contained any lease elements. If the contract was not a lease in its entirety but contained separable lease elements, the entity would then separate the lease elements from the nonlease elements by allocating arrangement consideration under ASC 840 and accounting for those elements separately. That is, the nonlease elements would be evaluated under ASC 815 for derivative accounting and the lease elements would be accounted for under ASC 840. If the contract did not contain any lease elements, many entities historically concluded that the contract consisted of a single unit of accounting under ASC 815 by determining (1) the host contract and evaluating the host under derivative guidance or (2) whether the compound contract consisted of any embedded derivatives.

For example, an entity may evaluate a contract for the sale of power and RECs by first determining the host contract or element in the arrangement by assessing which of the two products more significantly drives the economics of the overall contract. In doing so, the entity may determine that the RECs are the host contract. As discussed in Section 4, the forward sale of RECs may not be a derivative because the market for RECs does not have sufficient liquidity to meet the net settlement criteria in ASC 815. In this case, the entity would evaluate the embedded power contract for separation under ASC 815 and may or may not determine that it is a separable embedded derivative.[1]

In contrast, under a multiple-element accounting policy approach, an entity would evaluate a compound contract for separate units of accounting by identifying the deliverables in the contract and determining whether (1) each of those deliverables has stand-alone value to the customer and (2) the delivery of any undelivered items is probable and substantially in the control of the seller. This multiple-element approach would most likely result in an entity concluding that the RECs and power sales are two separate units of accounting, and the entity would evaluate each unit separately as a lease or derivative contract. In many cases, the two approaches will result in similar conclusions about the unit of accounting. For more information on multiple-element arrangement accounting and the allocation of arrangement consideration, see Section 7.

[1] ASC 815 requires an embedded feature to meet three criteria for separation: (1) the economic characteristics and risks of the embedded derivative (e.g., power sales) are not clearly and closely related to the economic characteristics and risks of the host contract (e.g., RECs sales); (2) the entire contract is not remeasured at fair value under otherwise applicable U.S. GAAP, with changes in fair value reported in earnings; and (3) a separate instrument with the same terms as the embedded derivative (e.g., power sales) would, under ASC 815-10-15, be a derivative instrument.

We caution entities to reconsider any existing policy for compound contracts that results in the mark to fair value of certain products (e.g., RECs) that if separately sold would not result in mark-to-fair-value accounting. That is, an entity should challenge an accounting policy that results in the fair value accounting for products or forward sales of products that do not meet the net settlement criteria in ASC 815.

Separate Accounting for Each Unit

Once an entity determines the appropriate unit or units of accounting for a renewable energy sales contract, it must evaluate those units as leases, derivative contracts, or other nonderivative contracts. This publication does not discuss the specific scope of lease accounting; however, it does discuss the accounting for lease revenues from the lessor's perspective.

After evaluating the units for lease accounting, an entity would assess each unit for derivative accounting under ASC 815. A forward sale meets the definition of a derivative when it has the following three characteristics:

- Underlying, notional amount, payment provision.
- No initial net investment or an initial net investment that is smaller than would be required for other types of contracts that would be expected to have a similar response to changes in market factors.
- Provision for net settlement.

In general, power sales contracts that contain a notional as a result of the contract having a minimum or stated delivery quantity meet the definition of a derivative because the underlying commodity being sold meets the net settlement criterion (i.e., the underlying commodity is implicitly net settleable because it is readily convertible to cash). REC sales contracts, even if they contain a notional, generally do not meet the definition of a derivative because the underlying product being sold does not meet the net settlement criterion as a result of a lack of market liquidity (it is assumed in this assessment that the contract does not explicitly require net settlement). However, this conclusion about market liquidity is not universal.

If an entity does not account for units of accounting as a lease or derivative, it will account for them on an accrual basis under revenue recognition guidance.

Income Recognition for Each Unit

After determining whether each unit is a lease or derivative, an entity must determine the appropriate income recognition method. An entity's income recognition for any lease elements will require the entity to consider the guidance in ASC 840, which provides specific lease revenue recognition models (e.g., straight-line lease revenues over the term of the lease or lease revenues as contingent rentals over the term of the arrangement as power is generated). For more information on lease revenue recognition, see ASC 840.

For nonlease elements or arrangements, ASC 605-10-25-1 provides two factors for an entity to consider when determining whether to recognize revenue in a particular period: (1) being realized or realizable and (2) being earned. When evaluating a contract for the sale of power and RECs, a facility generally satisfies the first factor (i.e., being realized or realizable) when it generates and delivers power to the offtaker; however, some constituents may debate when it satisfies the second factor (i.e., being earned) for the sale of RECs. This is because RECs generally have a certification process that varies depending on the regulatory body responsible for the RECs, which may extend 60 days or longer after power generation from the renewable facility occurs. The debate revolves around whether (1) the certification process is substantive or requires significant effort by the generator or (2) that process is perfunctory or nonsubstantive and generally depends on the regulatory jurisdiction.

For REC sales, an entity should develop an accounting policy to establish the appropriate point at which revenue recognition occurs. This may be when the RECs are certified by the regulator, when the RECs are physically delivered to the customer or regulator, or when the RECs are generated (i.e., when the renewable power is generated resulting in the creation of RECs). Most importantly, different jurisdictions have different certification processes that can result in significant time lags between renewable power generation and REC certification. The accounting policy will depend on a number of factors, including the regulatory process for each particular type of REC and whether the entity has completed the earnings process (i.e., all revenue recognition criteria have been met).

In addition to evaluating nonlease elements or arrangements under general revenue recognition requirements, an entity must also evaluate them under specialized U.S. GAAP (i.e., ASC 605-980). This guidance contains two separate models of specialized revenue recognition.

The first is for contracts with scheduled price changes, as outlined in ASC 605-980-25-11 and 25-12. Specifically, the guidance requires an entity to consider:

- Whether revenue on a PPA that contains scheduled price changes should be recognized on the basis of the schedule prices or ratably over the term of the contract.
- Whether the accounting prescribed in the first issue changes if the PPA provides that total revenues for the term on the contract are determined by a separate, formula-based pricing arrangement.
- Whether the accounting prescribed in the first issue changes if the PPA provides that total revenues for the term of the contract are limited by a separate, formula-based pricing arrangement.

This model results in the recognition of revenue for the lesser of (1) the amount billed under the contract or (2) the amount determined by the kWhs sold during the period multiplied by the estimated average revenue per kWh over the term of the contract.

The second model of specialized guidance is for contracts containing both fixed and variable pricing terms. Specifically, it addresses how revenue should be recognized on a PPA that contains separate, specified terms for a fixed or scheduled price per kWh for one period, and a variable price per kWh (based on market prices, actual avoided costs, or formula-based pricing arrangements) for a different period, when neither a tracker account nor any other form of adjustment determines or limits the total revenues to be billed under the contract over its entire period. An entity recognizes revenue under this specialized guidance by separating the fixed and variable pricing components in the contract and recognizing (1) the revenue associated with the fixed or scheduled price period of the contract under the guidance associated with contracts with scheduled price changes, as outlined above, and (2) the revenue associated with the variable price period of the contract as billed, in accordance with the provisions of the contract for that period. The guidance in ASC 605-980-25-18 provides an exception that if the contractual terms during the separate fixed and variable portions of the PPA are not representative of the expected market rates at the inception of the PPA, the revenue associated with the entire PPA should be recognized in accordance with the first specialized recognition model above (i.e., ASC 605-980-25-11 and 25-12).

Structuring Project Arrangements and the Resulting Accounting and Tax Implications

The use of renewable energy tax benefits is a challenge for some renewable energy businesses. Although an entity may project business growth and future taxable income, as a result of current economic conditions, changing tax rules or circumstances (e.g., eligibility for bonus depreciation), or better-than-anticipated wind generation, an entity may be unable to use all the renewable energy tax benefits available to it. 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 deferred tax assets related to the tax credits associated with such benefits.

One means of addressing the challenge is for businesses to enter into partnerships or other structured arrangements with "green" investors or investors that are 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 renewable energy businesses and investors mutual opportunities to maximize their 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 tax benefits to investors, businesses are able to generate positive cash flow today by receiving cash in exchange for the benefits. In addition, structures give businesses the opportunity to avoid the administrative burden and scrutiny associated with analyzing renewable energy tax benefits for realization under ASC 740-10. In the early years of a wind project, renewable energy businesses often do not generate sufficient profits to avail themselves of the tax benefits. As a result, an entity would have to carry over unused tax credits and evaluate, on the basis of all available evidence, whether the tax credits are expected to be realized in accordance with ASC 740-10-30-2.

For investors, participating in structures offers two benefits: (1) the receipt of tax benefits that can be used to offset their own taxable income and (2) 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, investors were typically investment banks, but new types of investors have recently begun to explore structures. Such investors have similar characteristics, such as available cash for investing opportunities. As discussed below, renewable energy businesses have explored alternatives, but the most common approach in structures is for the investor to pay a large sum of cash upon inception of the arrangement. Such investors also carry a large tax liability as a result of strong operating performance that increases their taxable income. Perhaps, the greatest motivation for investors in structures is receipt of tax benefits that allow them to offset their tax liabilities. In addition, such investors are often predisposed to marketing themselves as "green"; by entering into structures, they are able to advertise themselves as being environmentally-friendly and focused on renewable energy alternatives.

Features and Types of Structures

The features allowing structures to receive favorable tax treatment are similar. 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 equity interest in the partnership 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 defined period, the renewable energy business has the ability, but not the requirement, to repurchase the investor's partnership interest. This arrangement allows both the renewable energy business and the investor the ability 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.

Although the actual terms and provisions may vary, structures contain the following features[2] so that favorable tax treatment is ensured:

- 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 structures, the investor has at least a 5 percent interest in partnership income and gain 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 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 cash receipts from investors. In many common arrangements, the investor makes a large, up-front cash payment upon formation of the partnership. The amount of cash is meant to capture, based on the negotiated arrangement, 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

As noted above, renewable energy businesses often establish a partnership and sell a portion of the partnership interest to the investor. In accounting for the sale of such partnership interest, more than one approach may be appropriate.

One method may be 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. It states, in part:

[2] As summarized from the safe harbor guidance in IRS Revenue Procedure 2007-65. Although they are typically used for wind partnerships with production tax credits, the features are also often found in structures.

> 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.

If one concludes that the sale of the partnership interest is within the scope of ASC 360-20, the next determination is how to account for the sale. ASC 360-20 explains that two criteria must be met when entities use the full accrual method to recognize the profit when 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:

> 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 is structured in a manner that prevents recognition of profit by the full accrual method, renewable energy businesses must account for the sale of partnership interest under one of the other methods described in ASC 360-20-40-28 through 40-64. Application of one of these other methods (e.g., deposit, financing, leasing, profit-sharing) requires the use of judgment based on specific facts and circumstances. However, when applying these 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 disclosure are appropriate and consistent.

Another acceptable approach 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. A noncontrolling interest is sometimes called a minority interest.

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 sold 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 of such accounting on the balance sheet, income statement, and cash flow statement to ensure that the accounting and disclosures are appropriate and consistent, as it would for a sale of real estate.

The accounting and reporting considerations discussed above are from the perspective of renewable energy businesses. Consolidation implications should also be kept in mind. Both renewable energy businesses and investors need to evaluate structures under ASC 810 to determine which party is required to consolidate them.

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 the “Features and Types of Structures” section and must be met to ensure that the IRS will not challenge the arrangements. Note that Rev. Proc. 2007-65 only applies to partnerships in wind projects.

Appendix A
Abbreviations

Abbreviation	Description
ABS	asset-backed securities
ADITC	accumulated deferred investment tax credits
AICPA	American Institute of Certified Public Accountants
AMI	advanced metering infrastructure
AOCI	accumulated other comprehensive income
ARO	asset retirement obligation
ARRA	American Recovery and Reinvestment Act of 2009
ASC	FASB Accounting Standards Codification
ASU	FASB Accounting Standards Update
CAQ	Center for Audit Quality (affiliated with the AICPA)
C&DIs	SEC Compliance and Disclosure Interpretations
CFO	chief financial officer
CFTC	Commodity Futures Trading Commission
COD	commercial operation date
CRR	congestion revenue right
ED	exposure draft
EITF	Emerging Issues Task Force
EPI	engineering, procurement, construction
ERCOT	Electric Reliability Council of Texas
FAF	Financial Accounting Foundation
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FIFO	first-in first-out
FRM	SEC's Financial Reporting Manual
FSP	FASB Staff Position
FTR	financial transmission rights
FV-NI	fair value through net income
FV-OCI	fair value through other comprehensive income
GAAP	generally accepted accounting principles

IAS	International Accounting Standards
IASB	International Accounting Standards Board
ICFR	internal control over financial reporting
IFRIC	International Financial Reporting Interpretations Committee
IFRS	International Financial Reporting Standards
Industry Guide	Securities Act Industry Guide
Interpretation	FASB Interpretation
IPO	initial public offering
IRC	Internal Revenue Code
IRS	Internal Revenue Service
ISDA	International Swap Dealer's Association agreement
ITC	investment tax credit
kWh	kilowatt hour
LIFO	last-in first-out
LLC	limited liability company
MACRS	modified accelerated cost recovery system
MD&A	Management's Discussion and Analysis
MISO	Midwest Independent Transmission System Operator
MNA	master netting agreement
MoU	Memorandum of Understanding
NPNS	normal purchase normal sale
OCI	other comprehensive income
OPEB	other postemployment benefit
OTC	over the counter
P&U	power and utilities
PGA	purchased gas adjustment
PCAOB	Public Company Accounting Oversight Board
PJM	PJM Interconnection LLC
PLR	private letter ruling

PPA	power purchase agreement
PP&E	property, plant, and equipment
PTC	production tax credit
QPE	qualified progress expenditure
QSPE	qualified special-purpose entity
REC	renewable energy certificate
Regulation	SEC Regulation
RRA	rate-regulated activities
SAB	SEC Staff Accounting Bulletin
SAS	Statement on Auditing Standards
SEC or Commission	Securities and Exchange Commission
TPE	third-party evidence
VI	variable interest
VIE	variable interest entity
VSOE	vendor-specific objective evidence
XBRL	eXtensible Business Reporting Language

Appendix B
Glossary of Topics, Standards, and Regulations

Readers seeking additional information about the topics discussed in this publication and other activities of key standard-setters and regulators may find information on the following Web sites:

- The FASB Web site at www.fasb.org
- The SEC Web site at www.sec.gov
- The PCAOB Web site at www.pcaobus.org
- The AICPA Web site at www.aicpa.org
- The IFRS Web site at www.ifrs.org

The following represents a listing of technical resources used in drafting this document:

FASB Accounting Standards Codification Subtopic 205-20, *Presentation of Financial Statements: Discontinued Operations*

FASB Accounting Standards Codification Subtopic 220-10, *Comprehensive Income: Overall*

FASB Accounting Standards Codification Subtopic 230-10, *Statement of Cash Flows: Overall*

FASB Accounting Standards Codification Topic 250, *Accounting Changes and Error Corrections*

FASB Accounting Standards Codification Topic 270, *Interim Reporting*

FASB Accounting Standards Codification Subtopic 270-10, *Interim Reporting: Overall*

FASB Accounting Standards Codification Topic 310, *Receivables*

FASB Accounting Standards Codification Topic 323, *Investments — Equity Method and Joint Ventures*

FASB Accounting Standards Codification Topic 330, *Inventory*

FASB Accounting Standards Codification Subtopic 330-10, *Inventory: Overall*

FASB Accounting Standards Codification Topic 350, *Intangibles — Goodwill and Other*

FASB Accounting Standards Codification Subtopic 350-30, *Intangibles — Goodwill and Other: General Intangibles Other Than Goodwill*

FASB Accounting Standards Codification Topic 360, *Property, Plant, and Equipment*

FASB Accounting Standards Codification Subtopic 360-10, *Property, Plant, and Equipment: Overall*

FASB Accounting Standards Codification Subtopic 360-20, *Property, Plant, and Equipment: Real Estate Sales*

FASB Accounting Standards Codification Subtopic 360-970, *Property, Plant, and Equipment: Real Estate — General*

FASB Accounting Standards Codification Subtopic 410-30, *Asset Retirement and Environmental Obligations: Environmental Obligations*

FASB Accounting Standards Codification Topic 450, *Contingencies*

FASB Accounting Standards Codification Subtopic 450-20, *Contingencies: Loss Contingencies*

FASB Accounting Standards Codification Topic 460, *Guarantees*

FASB Accounting Standards Codification Subtopic 460-10, *Guarantees: Overall*

FASB Accounting Standards Codification Topic 605, *Revenue Recognition*

FASB Accounting Standards Codification Subtopic 605-10, *Revenue Recognition: Overall*

FASB Accounting Standards Codification Subtopic 605-25, *Revenue Recognition: Multiple-Element Arrangements*

FASB Accounting Standards Codification Subtopic 605-980, *Revenue Recognition: Regulated Operations*

FASB Accounting Standards Codification Topic 715, *Compensation — Retirement Benefits*

FASB Accounting Standards Codification Subtopic 715-20, *Compensation — Retirement Benefits: Defined Benefit Plans — General*

FASB Accounting Standards Codification Subtopic 715-30, *Compensation — Retirement Benefits: Defined Benefit Plans — Pension*

FASB Accounting Standards Codification Subtopic 715-60, *Compensation — Retirement Benefits: Defined Benefit Plans — Other Postretirement*

FASB Accounting Standards Codification Subtopic 715-80, *Compensation — Retirement Benefits: Multiemployer Plans*

FASB Accounting Standards Codification Subtopic 720-15, *Other Expenses: Start-Up Costs*

FASB Accounting Standards Codification Topic 740, *Income Taxes*

FASB Accounting Standards Codification Subtopic 740-10, *Income Taxes: Overall*

FASB Accounting Standards Codification Subtopic 740-270, *Income Taxes: Interim Reporting*

FASB Accounting Standards Codification Topic 805, *Business Combinations*

FASB Accounting Standards Codification Subtopic 805-10, *Business Combinations: Overall*

FASB Accounting Standards Codification Subtopic 805-20, *Business Combinations: Identifiable Assets and Liabilities, and Any Noncontrolling Interest*

FASB Accounting Standards Codification Topic 810, *Consolidation*

FASB Accounting Standards Codification Subtopic 810-10, *Consolidation: Overall*

FASB Accounting Standards Codification Topic 815, *Derivatives and Hedging*

FASB Accounting Standards Codification Subtopic 815-10, *Derivatives and Hedging: Overall*

FASB Accounting Standards Codification Subtopic 815-15, *Derivatives and Hedging: Embedded Derivatives*

FASB Accounting Standards Codification Subtopic 815-20, *Derivatives and Hedging: Hedging — General*

FASB Accounting Standards Codification Subtopic 815-30, *Derivatives and Hedging: Cash Flow Hedges*

FASB Accounting Standards Codification Topic 820, *Fair Value Measurements and Disclosures*

FASB Accounting Standards Codification Subtopic 820-10, *Fair Value Measurements and Disclosures: Overall*

FASB Accounting Standards Codification Subtopic 835-20, *Interest: Capitalization of Interest*

FASB Accounting Standards Codification Topic 840, *Leases*

FASB Accounting Standards Codification Subtopic 840-10, *Leases: Overall*

FASB Accounting Standards Codification Topic 855, *Subsequent Events*

FASB Accounting Standards Codification Topic 860, *Transfers and Servicing*

FASB Accounting Standards Codification Subtopic 860-20, *Transfers and Servicing: Sales of Financial Assets*

FASB Accounting Standards Codification Topic 932, *Extractive Activities — Oil and Gas*

FASB Accounting Standards Codification Topic 944, *Financial Services — Insurance*

FASB Accounting Standards Codification Topic 952, *Franchisors*

FASB Accounting Standards Codification Topic 980, *Regulated Operations*

FASB Accounting Standards Codification Subtopic 980-10, *Regulated Operations: Overall*

FASB Accounting Standards Codification Subtopic 980-340, *Regulated Operations: Other Assets and Deferred Costs*

FASB Accounting Standards Codification Subtopic 980-405, *Regulated Operations: Liabilities*

FASB Accounting Standards Codification Subtopic 980-605, *Regulated Operations: Revenue Recognition*

FASB Accounting Standards Codification Subtopic 980-715, *Regulated Operations: Compensation — Retirement Benefits*

FASB Accounting Standards Codification Subtopic 980-740, *Regulated Operations: Liabilities: Income Taxes*

FASB Accounting Standards Codification Topic 985, *Software*

FASB Accounting Standards Update No. 2010-10, *Amendments for Certain Investment Funds*

FASB Accounting Standards Update No. 2010-06, *Improving Disclosures About Fair Value Measurements*

FASB Accounting Standards Update No. 2010-03, *Oil and Gas Reserve Estimation and Disclosures*

FASB Accounting Standards Update No. 2009-17, *Improvements to Financial Reporting by Enterprises Involved With Variable Interest Entities*

FASB Accounting Standards Update No. 2009-16, *Accounting for Transfers of Financial Assets*

FASB Accounting Standards Update No. 2009-13, *Multiple-Deliverable Revenue Arrangements — a Consensus of the FASB Emerging Issues Task Force*

FASB Statement No. 167, *Amendments to FASB Interpretation No. 46(R)*

FASB Interpretation No. 46 (R), *Consolidation of Variable Interest Entities — an interpretation of ARB No. 51*

FASB Staff Position No. FIN 46(R)-6, "Determining the Variability to Be Considered in Applying FASB Interpretation No. 46(R)"

EITF Issue No. 08-1, "Revenue Arrangements With Multiple Deliverables"

EITF Issue No. 01-8, "Determining Whether an Arrangement Contains a Lease"

EITF Issue No. 00-21, "Revenue Arrangements With Multiple Deliverables"

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Center for Audit Quality (CAQ) Alert No. 2010-21, "New Standard on Accounting for Variable Interest Entities — Section 404 Considerations"

Center for Audit Quality (CAQ) Alert No. 2010-20, "New Standard on Accounting for Variable Interest Entities — Transition Questions for SEC Registrants"

SEC Staff Accounting Bulletin Topic 12, "Oil and Gas Producing Activities"

SEC Staff Accounting Bulletin Topic 13, "Revenue Recognition"

SEC Staff Accounting Bulletin 113, "Modernization of Oil and Gas Reporting"

SEC Regulation S-X, Rule 3-05, "Financial Statements of Businesses Acquired or to Be Acquired"

SEC Regulation S-X, Rule 3-14, "Instructions for Real Estate Operations to Be Acquired"

SEC Regulation S-X, Rule 4-10, "Financial Accounting and Reporting for Oil and Gas Producing Activities Pursuant to the Federal Securities Laws and the Energy Policy and Conservation Act of 1975"

SEC Regulation S-X, Article 11, "Pro Forma Financial Information"

SEC Regulation S-K, Item 10(e), "Use of Non-GAAP Financial Measures in Commission Filings"

SEC Regulation S-K, Item 101, "Description of Business"

SEC Regulation S-K, Item 103, "Legal Proceedings"

SEC Regulation S-K, Item 303, "Management's Discussion and Analysis of Financial Condition and Results of Operations"

SEC Regulation S-K, Item 401, "Directors, Executive Officers, Promoters, and Control Persons"

SEC Regulation S-K, Item 402(a), "Executive Compensation; General"

SEC Regulation S-K, Item 402(c), "Executive Compensation; Summary Compensation Table"

SEC Regulation S-K, Item 402(s), "Executive Compensation; Narrative Disclosure of the Registrant's Compensation Policies and Practices as They Relate to the Registrant's Risk Management"

SEC Regulation S-K, Item 407, "Corporate Governance"

SEC Regulation S-K, Item 503, "Prospectus Summary, Risk Factors, and Ratio of Earnings to Fixed Charges"

SEC Regulation S-K, Subpart 229.1200, "Disclosure by Registrants Engaged in Oil and Gas Producing Activities"

SEC Final Rule Release No. 33-8995, *Modernization of Oil and Gas Reporting*

SEC Final Rule Release No. 33-9089, *Proxy Disclosure Enhancements*

SEC Final Rule Release No. 33-9089A, *Proxy Disclosure Enhancements: Correction*

SEC Final Rule Release No. 33-9142, *Internal Control Over Financial Reporting in Exchange Act Periodic Reports of Non-Accelerated Filers*

SEC Proposed Rule No.33-9117, *Asset-Backed Securities*

SEC Proposed Rule No.33-9142, *Short-Term Borrowings Disclosure*

SEC Proposed Rule No. 33-9148, *Disclosure for Asset-Backed Securities Required by Section 943 of the Dodd-Frank Wall Street Reform and Consumer Protection Act*

SEC Proposed Rule No.33-9153, *Shareholder Approval of Executive Compensation and Golden Parachute Comparison*

SEC Proposed Rule No. 33-9150, *Issuer Review of Assets in Offerings of Asset-Backed Securities*

SEC Interpretive Release No. 33-9144, *Commission Guidance on Presentation of Liquidity and Capital Resources Disclosures in Management's Discussion and Analysis*

Securities Act Industry Guide 2, "Disclosure of Oil and Gas Operations"

IFRS 1, *First-time Adoption of International Financial Reporting Standards*

IFRS 4, *Insurance Contracts*

IFRS 5, *Non-current Assets Held for Sale and Discontinued Operations*

IFRS 6, *Exploration for and Evaluation of Mineral Resources*

IFRS 7, *Financial Instruments: Disclosures*

IFRS 9, *Financial Instruments*

IAS 2, *Inventories*

IAS 12, *Income Taxes*

IAS 16, *Property, Plant and Equipment*

IAS 20, *Accounting for Government Grants and Disclosure of Government Assistance*

IAS 28, *Investments in Associates*

IAS 36, *Impairment of Assets*

IAS 37, *Provisions, Contingent Liabilities and Contingent Assets*

IAS 38, *Intangible Assets*

IAS 39, *Financial Instruments: Recognition and Measurement*

IAS 40, *Investment Property*

IFRIC 1, *Changes in Existing Decommissioning, Restoration and Similar Liabilities*

IFRIC 4, *Determining Whether an Arrangement Contains a Lease*

FASB Accounting Standards Codification

General Principles

105 – Generally Accepted Accounting Principles

Presentation

205 – Presentation of Financial Statements

210 – Balance Sheet

215 – Statement of Shareholder Equity

220 – Comprehensive Income (FAS 130)

225 – Income Statement

230 – Statement of Cash Flows (FAS 95)

235 – Notes to Financial Statements

250 – Accounting Changes and Error Corrections (FAS 154)

255 – Changing Prices

260 – Earnings per Share (FAS 128)

270 – Interim Reporting (APB 28)

272 – Limited Liability Entities

274 – Personal Finance Statements

275 – Risks and Uncertainties

280 – Segment Reporting (FAS 131)

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320 – Investments — Debt and Equity Securities (FAS 115)

323 – Investments — Equity Method and Joint Ventures (APB 18)

325 – Investments — Other

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340 – Other Assets and Deferred Costs

350 – Intangibles — Goodwill and Other (FAS 142)

360 – Property, Plant, and Equipment (FAS 144)

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405 – Liabilities

410 – Asset Retirement and Environmental Obligations (FAS 143)

420 – Exit or Disposal Cost Obligations (FAS 146)

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450 – Contingencies (FAS 5)

460 – Guarantees (FIN 45)

470 – Debt

480 – Distinguishing Liabilities From Equity (FAS 150)

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505 – Equity

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605 – Revenue Recognition

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705 – Cost of Sales and Services

710 – Compensation — General

712 – Compensation — Nonretirement Postemployment Benefits (FAS 112)

715 – Compensation — Retirement Benefits (FAS 87; 88; 150)

718 – Compensation — Stock Compensation (FAS 123(R))

720 – Other Expenses

730 – Research and Development (FAS 2)

740 – Income Taxes (FAS 109/FIN 48)

Broad Transactions

805 – Business Combinations (FAS 141(R))

808 – Collaborative Arrangements

810 – Consolidation (FIN 46(R)/ARB 51/FAS 160)

815 – Derivatives and Hedging (FAS 133)

820 – Fair Value Measurements and Disclosures (FAS 157)

825 – Financial Instruments (FAS 159)

830 – Foreign Currency Matters (FAS 52)

835 – Interest

840 – Leases (FAS 13)

845 – Nonmonetary Transactions (APB 29)

850 – Related Party Disclosures

852 – Reorganizations

855 – Subsequent Events (FAS 165)

860 – Transfers and Servicing (FAS 140)

Industry

905 – Agriculture

908 – Airlines

910 – Contractors — Construction

912 – Contractors — Federal Government

915 – Development Stage Entities

920 – Entertainment — Broadcasters

922 – Entertainment — Cable Television

924 – Entertainment — Casinos

926 – Entertainment — Films

928 – Entertainment — Music

930 – Extractive Activities — Mining

932 – Extractive Activities — Oil and Gas

940 – Financial Services — Broker and Dealers

942 – Financial Services — Depository and Lending

944 – Financial Services — Insurance

946 – Financial Services — Investment Companies

948 – Financial Services — Mortgage Banking

950 – Financial Services — Title Plant

952 – Franchisors

954 – Health Care Entities

958 – Not-for-Profit Entities

960 – Plan Accounting — Defined Benefit Pension Plans

962 – Plan Accounting — Defined Contribution Pension Plans

965 – Plan Accounting — Health and Welfare Benefit Plans

970 – Real Estate — General

972 – Real Estate — Common Interest Realty Associations

974 – Real Estate — Real Estate Investment Trusts

976 – Real Estate — Retail Land

978 – Real Estate — Time-Sharing Activities

980 – Regulated Operations

985 – Software

995 – U.S. Steamship Entities

Appendix C
Deloitte Specialists and Acknowledgements

U.S. Energy & Resources Contacts

Greg Aliff
National Industry Leader, Energy & Resources
National Sector Leader, Power & Utilities
Deloitte & Touche USA LLP
+1 703-251-4380
galiff@deloitte.com

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

Marlene Motyka
Power & Utilities Functional Sector Leader, FAS
Deloitte Financial Advisory Services LLP
+1 212 436 2615
mmotyka@deloitte.com

Greg Seelagy
National Functional Industry Leader, AERS
Power & Utilities Functional Sector Leader, AERS
Deloitte & Touche LLP
+1 215-405-5580
gseelagy@deloitte.com

Brad Seltzer
National Functional Industry Leader, Tax
Power & Utilities Functional Sector Leader, Tax
Deloitte Tax LLP
+1 202-220-2050
bseltzer@deloitte.com

Jan Umbaugh
Industry Professional Practice Director, Power & Utilities
Deloitte & Touche LLP
+1 561-962-7706
jumbaugh@deloitte.com

Bill Graf
Industry Professional Practice Director, Power & Utilities
Deloitte & Touche LLP
+1 504-561-7130
wgraf@deloitte.com

Gary Adams
National Sector Leader, Oil & Gas
Deloitte & Touche USA LLP
+1 713-982-4160
gaadams@deloitte.com

Erik Gilberg
National Functional Industry Leader, Consulting
Deloitte Consulting LLP
+1 415-783-4043
egilberg@deloitte.com

Sampat Prakash
Oil & Gas Functional Sector Leader, Consulting
Deloitte Consulting LLP
+1 713-982-2723
saprakash@deloitte.com

Jed Shreve
National Functional Industry Leader, FAS
Oil & Gas Functional Sector Leader, FAS
Deloitte Financial Advisory Services LLP
+1 713-982-4393
jshreve@deloitte.com

John England
Oil & Gas Functional Sector Leader, AERS
Deloitte & Touche LLP
+1 713-982-2556
jengland@deloitte.com

Jeff Wright
Oil & Gas Functional Sector Leader, Tax
Deloitte Tax LLP
+1 713-982-4940
jeffwright@deloitte.com

Dan Odom
Industry Professional Practice Director, Oil & Gas
Deloitte & Touche LLP
+1 214-840-7324
dodom@deloitte.com

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

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Yvonne Rudek

Appendix D
Other Resources and Upcoming Events

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Events

November 30, 2010

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December 1, 2010

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