Power & Utilities
Accounting, Financial Reporting, and Tax Update
January 2015
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January 2015

We are pleased to present our 13th annual Accounting, Financial Reporting, and Tax Update for the power and utilities (P&U) industry. Our industry continues to face changing markets, new legislation, environmental initiatives, regulatory pressures, and emerging businesses and technologies. This publication discusses accounting, tax, and regulatory matters that P&U entities will need to consider as a result of these changes, including updates to SEC, FASB, IFRS, and tax guidance, and focuses on specialized industry accounting topics that frequently affect rate-regulated entities. New to this year’s publication are sections on accounting and reporting considerations related to (1) carve-out financial statements and (2) the FASB’s and IASB’s new revenue standard. Also included is a section on accounting and reporting concerns specific to renewable energy.

To help P&U entities understand and address potential challenges in the accounting for and reporting of financial instruments, leases, and other topics on which the FASB has issued proposed standards, this publication discusses these proposals and highlights nuances that could affect our industry.

We hope you find this update a useful resource, and we welcome your feedback. As always, we encourage you to contact your Deloitte team or any of the Deloitte specialists in Appendix C for additional information and assistance.

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

**Role of M&A in the P&U Sector**

M&A is one of the more compelling and, potentially, expedient strategies for delivering value in the near term and managing business risks. But M&A is generally not among the top options regulated P&U companies consider, in part because they anticipate a variety of barriers, such as complex and challenging regulatory requirements, long approval timelines, and uncertainty concerning the extent of the alternatives available to them. P&U companies may also avoid M&A because its benefits are difficult to articulate and quantify (except for traditional synergistic savings related to reduced operating costs).

However, the forces transforming the industry, combined with changing market conditions, are modifying the lens through which P&U companies view M&A. The new lens reveals expanded opportunities for win-win scenarios that benefit both customers and shareholders. Traditional synergistic cost savings, which typically flow primarily to customers in a regulated environment, will continue to be a powerful impetus for M&A activity. But so will transactions that foster competition, innovation, reliability and resilience, and compliance with environmental and other regulatory mandates.

The benefits of economies of scale, the strengthening of balance sheets to meet rising capital requirements, and the allure of new and often diversified revenue streams largely catalyzed M&A activity for P&U companies in 2013 and throughout 2014. Going forward, these factors are expected not only to remain relevant but to pack an added punch. Shifting market conditions, such as rising interest rates, are likely to increase the urgency for P&U companies to consider M&A as a strategic option.

While synergistic cost savings are still a major rationale for M&A activity, other types of synergies are gaining in importance — and even becoming an imperative for some companies. Such synergies include those related to information technology (e.g., advanced metering infrastructure and other smart-grid technology), customer relationship management, and advanced data analytics. Larger entities may more easily afford and more readily take advantage of these high-ticket systems and technologies. Indeed, a utility that has not yet deployed smart meters may wish to acquire or merge with one that has, not only to obtain the technology itself but also to gain an understanding of how to successfully deploy it and derive value from it. The same could apply to technologies and leading practices related to cyber risk and environmental compliance.

Asset optionality is another emerging synergistic benefit of M&A activity that some companies are evaluating. An entity with a diverse portfolio of assets may be more able to maximize the value of those assets as marketplace dynamics change and, conversely, to better manage potential downside risks.

The rationale for M&A activity in a regulated-utility context is broadening beyond the traditional view that such activity should be substantially justified on the basis of synergistic cost savings that flow through to customers. M&A can now be viewed as a lever a company can pull to achieve a variety of strategic objectives that benefit customers and shareholders alike beyond the quantifiable, and generally short-term, impact on customers’ electricity prices. Accessing lower-cost capital, managing enterprise risks (e.g., achieving environmental compliance and mitigating cyberattacks), and lowering overall corporate risk through enhanced asset optionality are just a few of the corporate objectives that M&A can advance. While achieving these objectives may not directly result in lower prices for utility customers, the inherent advantages of a healthy enterprise ultimately benefit the company’s regulated operations and its customers over the long term.

For more information, see Deloitte’s *Evaluating M&A Through a Changing Utility Lens — A Fresh Look at M&A’s Role in Power and Utilities.*

**M&A Activity**

M&A continued to play an active role in the P&U sector in 2014. Acquiring companies have sought to increase their financial security, reduce their risk profiles and costs, strengthen their balance sheets, diversify their state regulatory risk, and enhance their abilities to employ large capital investment programs. Some companies with regulated operations have
sought to grow their rate bases and provide more stable, predictable earnings. Further, over the past few years, companies in the merchant power sector have been expanding their operations through M&A. As a result of this trend, companies that are looking to exit the merchant power sector have had greater opportunities to do so.

A number of significant M&A activities have been completed in the P&U sector over the past year, including the following:


- **NRG Energy Inc. and Dominion Resources Inc.** — On March 31, 2014, NRG Energy Inc. completed its acquisition of Dominion Resources Inc.’s unregulated electric retail energy marketing business, including Dominion Retail Inc. and Cirro Group Inc.

- **Laclede Group Inc. and Energen Corp.** — On August 31, 2014, Laclede Group Inc. completed its acquisition of Alabama Gas Corp. from Energen Corp. The acquisition was formally approved by the Alabama Public Service Commission on July 22, 2014.

- **NorthWestern Energy and PPL Montana’s hydro assets** — On November 19, 2014, NorthWestern Energy announced that it has completed its acquisition of 11 hydroelectric facilities from PPL Montana for approximately $890 million.

- **Berkshire Hathaway Energy and AltaLink LP** — On December 1, 2014, Berkshire Hathaway Energy announced that it has completed its acquisition of AltaLink LP from SNC-Lavalin Inc. for approximately C$3.1 billion ($2.7 billion) in cash. AltaLink LP has 280 substations and approximately 12,000 kilometers of transmission lines.

Other significant M&A activity includes the following:

- **Exelon Corp.** announced on April 30, 2014, that it plans to acquire Pepco Holdings Inc. for approximately $27.25 per share or approximately $6.8 billion in cash. Pepco Holdings Inc. serves customers in Delaware, the District of Columbia, Maryland, and New Jersey and provides (1) regulated electricity service through Potomac Electric Power Co. and Atlantic City Electric Co. and (2) regulated electricity and natural gas services through Delmarva Power & Light Co. On October 8, 2014, the Virginia State Corporate Commission approved the proposed merger. FERC approved the proposed merger on November 20, 2014. However, approval is pending from the Delaware Public Service Commission, the District of Columbia Public Service Commission, the Maryland Public Service Commission, and the New Jersey Board of Public Utilities.

  On October 29, 2014, in a move to bolster its financing of the acquisition, Exelon Corp. signed an agreement to divest its proportional ownership stake in the Keystone and Conemaugh generating facilities in Pennsylvania for expected total sales proceeds of approximately $475 million. When the proposed acquisition was announced, Exelon Corp. said it was planning to raise up to $1 billion from the sale of noncore assets to help fund it.
In addition, Exelon Corp. sold its Safe Harbor hydro plant in Pennsylvania; reached agreements to sell the Quail Run plant in Texas and the Fore River plant in Massachusetts; and filed an application with FERC on October 3, 2014, to sell the West Valley City plant in Utah. The pretax proceeds from these sales are expected to be $1.3 billion.

- Wisconsin Energy Corp. announced on June 23, 2014, that it has reached a definitive agreement to acquire Integrys Energy Group Inc. for approximately $9.1 billion in stock and cash. Integrys Energy Group Inc.’s electric and gas utilities serve customers in Illinois, Michigan, Minnesota, and Wisconsin. The shareholders of both companies approved the acquisition on November 21, 2014. The acquisition is subject to approvals from FERC, the Federal Communications Commission, the Public Service Commission of Wisconsin, the Illinois Commerce Commission, the Michigan Public Service Commission, and the Minnesota Public Utilities Commission. The acquisition could be completed by the end of the third quarter of 2015.

- Dynegy Inc. announced on August 22, 2014, that it has signed two separate agreements to (1) acquire ownership interests in certain Midwest generation assets from Duke Energy Corp. and (2) purchase EquiPower Resources Corp. and Brayton Point Holdings LLC from Energy Capital Partners LLC (a total of 12,500 MW). Dynegy Inc. will pay $2.8 billion for the generation assets from Duke Energy Corp. and $3.45 billion for EquiPower Resources Corp. and Brayton Point Holdings LLC. Both acquisitions are subject to FERC approval and are expected to be completed in the first quarter of 2015.

- Cleco Corp. announced on October 20, 2014, that it has agreed to be acquired by a group of investors led by Macquarie Infrastructure & Real Assets Inc. and British Columbia Investment Management Corp. The deal is valued at approximately $4.7 billion, including approximately $1.3 billion of outstanding debt. Cleco Corp. would continue to operate as an independent company led by local management based in Pineville, Louisiana. The transaction is subject to approvals from Cleco Corp.’s shareholders, FERC, and the Louisiana Public Service Commission and could be completed in the second half of 2015.

- SunEdison Inc. announced on November 17, 2014, that it has entered into a definitive agreement to acquire First Wind Holdings LLC for approximately $2.4 billion. First Wind Holdings LLC is a renewable energy developer and operator of utility-scale power projects in the United States. In addition to the acquisition, SunEdison Inc. is purchasing a development pipeline and project backlog of more than 1,600 MW. The pipeline and project backlog will be added to the list of SunEdison’s projects, with right of first refusal for SunEdison Inc.’s yieldco, TerraForm Power Inc. The acquisition is subject to customary conditions and regulatory approvals and is expected to be completed during the first quarter of 2015.

- NextEra Energy Inc. announced on December 3, 2014, that it has entered into an agreement to acquire Hawaiian Electric Industries Inc. for approximately $4.3 billion. The acquisition would include the assumption of $1.7 billion in debt by NextEra Energy Inc. but would exclude Hawaiian Electric Industries Inc.’s banking subsidiary, ASB Hawaii. Hawaiian Electric Industries Inc. plans to spin off ASB Hawaii to its shareholders and establish the bank as an independent publicly traded company. The acquisition is subject to approvals from Hawaiian Electric Industries Inc.’s shareholders, the Hawaii Public Utilities Commission, and FERC; termination of the waiting period under the Hart-Scott-Rodino Act; the spin-off of ASB Hawaii and the effectiveness of the related registration statements under SEC regulations; and additional regulatory approvals and other customary conditions. The acquisition is expected to be completed within one year.

M&A activity is likely to continue as the P&U sector reacts to environmental compliance requirements; the effects of varied natural gas prices; and, in some cases, the need to moderate customer rate increases. In some situations, regulatory approval can be a significant challenge and could influence whether companies will proceed with M&A activity.

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

Given the various challenges with operating nuclear facilities in the current market (e.g., economic conditions, public pressure), operators have been evaluating these facilities to determine whether they should shut them down before the end of their useful lives. In 2010, for example, Exelon Corp. announced that, as a result of economic conditions, it will retire the Oyster Creek Generating Station in New Jersey in 2019, which is 10 years before license expiration in 2029. In 2013, economic conditions also prompted two operators, Dominion Resources Inc. and Entergy Corp., to announce plans to shut down their facilities, citing operating costs that outweighed their compensation in the wholesale electricity market. Dominion Resources Inc. has closed its Kewaunee plant in Wisconsin, and Entergy Corp. shut down the reactor at its Vermont Yankee plant at the end of 2014. In 2014, the trend of low power prices, coupled with competition from renewable energy, continued. This trend could cause other nuclear facilities to follow in the footsteps of Kewaunee and Vermont Yankee.

Below is a discussion of regulations and other activity that could affect the future of nuclear facilities.

Clean Power Plan

On June 2, 2014, the EPA proposed the CPP, which could either benefit or hinder nuclear facilities, depending on the guidance in the final regulations. The CPP would require states to slash CO₂ emissions from existing plants through various means, including boosting generation from natural-gas-fired plants, idling coal plants, and adding renewable power. Nuclear facilities that are currently under construction (discussed below) would not count toward the reduction of CO₂ emissions under the CPP, since calculations of this reduction assume that a facility is running.

Most nuclear operators believe that, as currently proposed, the CPP does not sufficiently reward them for carbon-free sources of baseload power, such as electricity, approximately 20 percent of which is provided by nuclear facilities in the United States. The CPP details an approach in which carbon cuts “supported by retaining in operation [6 percent] of each state’s historical nuclear capacity should be factored into the state goals for the respective states.” The 6 percent is based on the 5.7 GW of the nuclear fleet that the U.S. Energy Information Agency (EIA) warned was at risk for retirement in its most recent Annual Energy Outlook.

This potential lack of support for existing nuclear generation leaves open the possibility that nuclear facilities could close and be replaced by CO₂-emitting power plants. Also, the EPA has stated that while the CPP’s goals are rate-oriented, states are invited to convert the rate goal to a mass goal or a flat cap on CO₂ emissions. A mass goal would benefit nuclear operators because it would obviate the need for them to buy allowances for CO₂ emissions.

NRC Regulations and Other Activity

Another challenge that nuclear facilities may encounter is the cost of implementing new, and complying with existing, regulations from the Nuclear Regulatory Commission (NRC). Below is a summary of recent regulations and other NRC activity that may affect the construction of nuclear facilities.

Pilot Programs

The NRC’s pilot programs could help the Commission prioritize its regulations. For example, one of the programs involves testing a possible reprioritization process that employs a 1–5 rating system, with “1” indicating the highest safety importance. The operators selected for the NRC pilot programs will be evaluating their regulatory priorities and expect to complete this evaluation by the end of the first quarter of 2015.

Development of New Nuclear Facilities

Challenges that companies may encounter when developing nuclear facilities include long lead times, large capital requirements, extensive permitting processes, and uncertain future demand for more capacity. Regarding this latter challenge, most of the new nuclear capacity in development was proposed before 2010, when projected demand for
electricity was significantly higher than it is now. New nuclear capacity already under construction (three projects), or for which companies applied for a combined license (eight projects) or for an early site permit (one project), is primarily associated with projects of utilities that investors own either wholly or in partnership with other companies, including municipal utilities.

From August 2012 to August 2014, the NRC instituted a self-imposed moratorium on licenses for nuclear plants. The moratorium, which was lifted on August 26, 2014, affected applications for combined licenses and early site permits, the latter of which are usually the first step in the regulatory process for a new nuclear facility. The status of applications for combined licenses also indicates the challenges with the regulatory process, since six applicants have suspended the process and two applicants have withdrawn from it.

Companies that are developing and constructing new nuclear facilities include the following:

- **Vogtle Electric Generating Plant Units 3 and 4** — In February 2012, the NRC issued construction and operating licenses for two new reactors at Vogtle’s plant in eastern Georgia. The plant is 45.7 percent owned by the operator, Georgia Power, a subsidiary of the Southern Company; 30 percent owned by Oglethorpe Power Corp.; 22.7 percent owned by the Municipal Electric Authority of Georgia; and 1.6 percent owned by the city of Dalton, Georgia. Units 3 and 4 are expected to begin commercial operations in the fourth quarters of 2017 and 2018, respectively.

- **Virgil C. Summer Nuclear Generating Station Units 2 and 3** — In March 2012, the NRC issued construction and operating licenses for the two proposed reactors at the Virgil C. Summer plant in South Carolina. Two-thirds of the plant is owned by the operator, a subsidiary of SCANA Corp., and one-third is owned by the South Carolina Public Service Authority (also known as Santee Cooper). There have been multiple delays with the construction of the reactors. Owing to the latest delay, which was announced on October 2, 2014, Units 2 and 3 are expected to begin commercial operations, respectively, in the (1) fourth quarter of 2018 or first quarter of 2019 and (2) fourth quarter of 2019 or first quarter of 2020.

- **Tennessee Valley Authority Watts Bar Unit 2** — In April 2012, the Tennessee Valley Authority (TVA) board of directors approved continuing the construction of the unit, which originally started in 1973; estimates have been revised for the budget and timeline. The TVA is more than halfway done with the almost 9,000 component tests that it is required to perform before commercial operation can begin and is expected to complete these tests by the end of 2015. Fuel is expected to be loaded into the reactor by May 14, 2015.

### Nuclear Waste

Storage of nuclear waste is yet another challenge that nuclear facilities may encounter. On August 26, 2014, the NRC issued a final rule affirming the feasibility of long-term storage of spent fuel waste at nuclear plant sites. The new guidance was issued in response to a 2012 ruling by the U.S. Court of Appeals for the District of Columbia Circuit (the “D.C. appeals court”) in which the court found that the NRC had violated the National Environmental Policy Act (NEPA) by licensing nuclear facilities without adequately considering the following potential dangers associated with three significant aspects of spent fuel storage: (1) the chance that a permanent repository may never be established, (2) the risk of leaks from the cooling pools that hold spent fuel rods for years until they are safe for transport to dry casks, and (3) the threat of radiation exposure resulting from fires at these spent fuel pools.

Before issuing the new rule, the NRC staff prepared an environmental impact statement in which it determined that the likelihood that spent fuel pools will accidentally drain or that any major accidents will result from these pools is remote. The NRC staff’s analysis described the pools as “massive, seismically-designed structures that are constructed from thick, reinforced concrete walls and slabs” and indicates that this design protects the pools against natural disasters or other problems that could lead to an accident.
However, between October 27 and October 29, 2014, four separate lawsuits were filed with the D.C. appeals court, arguing that the new rule continues to violate NEPA. The lawsuits were filed by (1) the attorneys general of New York, Connecticut, and Vermont; a coalition of environmental groups; the Prairie Island Indian Community; and the Natural Resources Defense Council.

**Rate-Case Activity**

The level of rate-case activity continued to be significant in 2014. This elevated level of activity is attributable to increased costs driven by generation and other infrastructure upgrades and expansion projects, gas pipeline integrity assessment and monitoring, environmental compliance expenditures, renewable generation mandates, and the impact of low growth in sales because of the economy and customer conservation.

For January through September 2014, the average return-on-equity (ROE) percentages for both electric and gas utilities, as set by regulators, were on par with the average ROE percentages in 2013 when adjusted for four rate cases for electric utilities in Virginia that incorporated ROE premiums as allowed by Virginia statutes for certain generation projects. The average ROE percentage for electric utilities in 2014 was approximately 10.00 percent, and the average ROE percentage in 2013 was approximately 10.02 percent. Further, the average ROE percentage set by regulators for gas utilities in 2014 was approximately 9.63 percent, and the average ROE in 2013 was approximately 9.68 percent. Despite the justified need for rate increases, regulators are cognizant of the impact of such increases on customers given the current economic conditions, which could affect rate-case outcomes.

Just as rate-case activity has increased over the past several years, so too have rate-freeze provisions. Rate-freeze provisions can be associated with merger approvals, rate-case settlements, or the establishment of alternative regulatory frameworks. Such provisions can also be required in exchange for a commission’s constructive treatment of other aspects of an entity’s operations or imposed as a penalty for mismanagement. Through the first three quarters of 2014, rate-freeze provisions were in effect in 29 jurisdictions for customers of 43 electric and 29 gas utilities. Many of the current rate-freeze provisions have original durations of less than four years, and approximately half of these are slated to expire in the next two years.

Because the level of rate-case activity continues to be significant, some electric utilities and their regulators are experimenting with alternative approaches to establishing rates. Such methods include cost trackers, inclusion of construction work-in-progress in rate base, revenue decoupling, forward test years, formula rates, and multiyear rate plans.

In particular, multiyear rate plans have been gaining in popularity. Thus far, 17 states have implemented such plans. In its February 2014 document *Innovative Ratemaking — Multiyear Rate Plans*, ScottMadden Inc. describes multiyear rate plans as possessing the following characteristics:

- They cover a period of three to five years.
- Annual rate increases are defined by attrition relief mechanisms (ARMs) that “are usually capped either in terms of rates or total revenue.” Examples of ARMs include:
  - **Stairsteps** — Predetermined rate or revenue increases that are based on forecasts for cost growth.
  - **Indexing** — Variable increases tied to an index (e.g., the CPI inflation rate).
  - **Hybrids** — Indexing for O&M and stairsteps for CapEx.
- Their structures sometimes include additional provisions, such as cost trackers; mechanisms for distributing excess earnings between a utility and its customers; and “off-ramps,” which facilitate plan suspension when earnings are unusually high or low.

Benefits of multiyear rate plans include more predictable revenue streams, lower regulatory costs, incentive to manage costs, and the ability of utilities to allocate resources to operations instead of rate case administration.
Future of Coal-Fired Generating Units

Questions continue to be raised about the future use of coal-fired generating units in the United States. Market dynamics, including low natural gas prices, the rising cost of coal, and reduced demand for electricity, have called into question the viability of operating coal-fired plants. In addition, regulators are pressuring power plants to further reduce their emissions, especially plants that use fossil fuel to generate electricity.

As a result of these factors, certain coal-fired generating units are slated to be retired over the next several years. Recent reports have indicated that companies have formalized plans to permanently shut off approximately 28,500 MW of capacity from 2015 through the end of 2026. In addition, some companies are planning to convert existing coal-fired generating units to burn other fuels such as natural gas or biomass. Recent reports have pointed out that nearly 5,500 MW has potentially been identified for conversion between 2015 and 2020. As the cost of replacement power and projected energy margins decrease, decreases in spot and forward natural gas prices may have a greater impact on the decision of whether to retrofit coal-fired generating units rather than retire them.

Retirements and the retrofitting of existing coal-fired units, as well as market dynamics and the current regulatory environment, may affect decisions about the construction of new power plants. For example, through December 2014, there have been no announcements about potential new coal-fired plants in the United States, which may indicate that there is little desire to expand the fleet of these plants. The sections below discuss regulatory developments that may affect the future of coal-fired generating units.

Clean Air Interstate Rule

In April 2005, the EPA issued the CAIR to regulate emissions of SO₂ and NOₓ from power plants, seeking to limit particles that drift from one state to another. The CAIR’s cap-and-trade system, which covers 27 eastern states and the District of Columbia, allows the states to meet their individual emissions budgets by employing either of two compliance options: (1) requiring power plants to participate in an EPA-administered interstate cap-and-trade system that caps emissions in two stages or (2) undertaking measures of their own choosing.

Cross-State Air Pollution Rule

The EPA continued its efforts to curtail power plant emissions by issuing the CSAPR in July 2011. This rule would have set limits on emissions from power plants in 28 eastern states via a new cap-and-trade program. While a federal appeals court vacated certain aspects of the CSAPR in August 2012, the U.S. Supreme Court ultimately ruled 6-2 to uphold it. The Supreme Court’s decision does not automatically reinstate the CSAPR; it simply reverts the case back to the appeals court, which may need to consider other challenges to the rule that were introduced but not subjected to a formal ruling. It is uncertain whether the appeals court will eventually allow enactment of the CSAPR and whether the EPA will ultimately decide to proceed with reinstatement. However, the rule’s provisions would need to be amended before it is reinstated (e.g., the EPA would need to revise the implementation timeline, since the original compliance dates have passed). Meanwhile, the CSAPR remains in effect.

Mercury and Air Toxics Standards

On December 16, 2011, the EPA issued the MATS rule to set a national standard for mercury emissions and to regulate power plant emissions of mercury, acid gases, and nonmercury metallic toxic pollutants. The MATS rule is intended to (1) prevent emission into the air of about 90 percent of the mercury in coal burned in power

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1 Source: http://www.sourcewatch.org/index.php/Coal_plant_retirements.
2 See footnote 1.
plants, (2) reduce acid gas emissions from power plants by 88 percent, and (3) reduce SO₂ emissions from power plants by 41 percent. Unlike the CSAPR or CAIR, the MATS rule is not a cap-and-trade program; no emissions allowances are involved. If a specific plant emits more mercury or other toxics than are permitted, that plant is not allowed to operate. Under the MATS rule, reductions are to be achieved starting in the first quarter of 2015.

**Clean Power Plan**

The EPA’s most recent legislation intended to reduce the toxic emissions from coal-fired power plants is the CPP, which the agency proposed on June 2, 2014. The CPP is a comprehensive plan that is designed to reduce existing emissions by fossil-fuel electric-generating-unit (EGU) plants. Under the CPP, by the year 2030, carbon emissions within the power sector would be reduced by about 30 percent compared with 2005 levels. The CPP is also expected to reduce other particle pollution, as well as NOₓ and SO₂ levels, by about 25 percent. The CPP is not a new set of rules or regulations but an initiative that would allow states to develop their own implementation plan to meet certain CO₂ emissions requirements. Under the CPP, states would still need to comply with existing federal and state emissions regulations such as the CAIR, the MATS, the NAAQS, and regional haze rules. However, these regulations would be supplemented by individualized state-developed strategies that would further reduce power plant emissions to meet a state’s CPP-defined goal. Comments on the proposed CPP were due by December 1, 2014. The EPA will assess the feedback received and is expected to issue a final rule in the first half of 2015.

For more information about the CPP, see Deloitte’s June 2014 *Power & Utilities Spotlight*.

The utility industry and nearly two dozen states have filed lawsuits regarding the CPP. In November 2014, the U.S. Supreme Court indicated that it would hear arguments on these cases during the spring of 2015. The court is expected to provide a final ruling by June 2015.

**Carbon Pollution Standards for New Power Plants**

On September 20, 2013, the EPA released its proposed carbon pollution standards for new power plants, which would limit emissions from new fossil-fuel-fired plants to 1,110 lbs. of CO₂ per MWh, considerably less than the average coal-fired plant now emits. The only fossil-fuel-fired power plants placed in service over the past few years that are capable of meeting the proposed rule’s requirements are combined-cycle gas turbine generators. To meet proposed emissions-rate requirements, coal-fired generating units would need to use technology such as carbon capture and storage to reduce emissions. If this proposed rule becomes effective, it is likely that no new coal-fired generating units will be constructed in the United States.

**EPA’s Final Rule on Coal Ash Disposal**

Ash ponds are one of the more common methods for disposing of coal combustion residuals (CCRs). While the use of ash ponds for the wet disposal of CCRs has its economic advantages, this approach is often criticized for not providing the same level of environmental protection as dry-handled disposal methods because of the potential for harmful toxins to seep into the water table. Though many states currently regulate the wet disposal of CCRs into ash ponds, there is no existing regulation related to this issue at the federal level.

On June 21, 2010, the EPA proposed a rule on CCR disposal in accordance with the Resource and Conservation Recovery Act (RCRA). The proposed rule contained two potential approaches. Under the first approach, CCRs would be designated as “hazardous waste” that is subject to the requirements of Subtitle C of the RCRA (i.e., specific handling of the waste would be required during its generation, transportation, storage, or disposal). In contrast, under the second approach, CCRs would be considered solid waste and would be subject to the requirements of Subtitle D (i.e., requirements would be applied to the management of the waste once it is delivered to surface impoundments and landfills). On December 19, 2014, after considering the feedback received, the EPA opted to issue a final rule under Subtitle D of the RCRA.

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³ CCRs, commonly referred to as coal ash, are materials that remain after coal is burned for electricity and include (1) fly ash, (2) bottom ash, (3) boiler slag, and (4) flue gas desulfurized gypsum.
The final rule, which applies to owners and operators of landfills and surface impoundments, establishes minimum national criteria for the safe disposal of solid waste CCR. The criteria address a wide spectrum of activities related to CCR solid waste disposal, including location restrictions; liner design criteria; structural integrity requirements; operating criteria; groundwater monitoring and corrective action requirements; closure and postclosure care requirements; and recordkeeping, notification, and Internet posting requirements.

To avoid adverse effects on health or the environment, the final rule also introduces restrictions on location of CCR disposal sites. These restrictions apply to (1) new CCR landfills, (2) new and existing CCR surface impoundments, and (3) all lateral expansions of CCR units. Location restrictions on existing CCR landfills are only applicable in unstable areas.

Next Steps

The final rule details the guidelines and time frames for initiating and completing closure activities related to CCR units, as well as reporting requirements for posting certain information in the facility’s operating record and maintaining the public availability of such required information.

The final rule will become effective 180 days after the date of its publication in the Federal Register.

The final rule on CCR disposal will affect many P&U companies. Companies will be required to remove waste solids from their surface impoundments and enhance their containment structures by installing a composite liner in both new and existing facilities while meeting structural integrity requirements. Landfills will similarly be subject to certain requirements (i.e., a liner will need to be installed in new landfills, though existing landfills will not be subject to this requirement).

The final rule also introduces certain operating criteria related to the day-to-day operations of CCR units as well as groundwater monitoring requirements. Each of these requirements may significantly increase the operating activities at a CCR unit, thereby increasing the resources and related costs associated with the disposal of CCRs.

Further, because the final rule contains closure and postclosure care requirements for coal ash impoundments, we expect that the rule will result in new or increased asset retirement obligations for affected companies in the period in which it becomes a legal obligation (as defined in ASC 410-20). We recommend that affected companies investigate and, as necessary, determine when the resulting rule requirements will become a legal obligation. We are aware that many industry participants have concluded that a legal obligation will not result before the date of the rule’s publication in the Federal Register.

Master Limited Partnerships, Yieldcos, and Real Estate Investment Trusts

Master Limited Partnerships (MLPs)

An MLP, as defined in the U.S. federal tax code, is a publicly traded entity that is subject to the same accounting, reporting, and regulatory requirements as a publicly traded corporation. Investors in an MLP have an advantage in that they are taxed as partners but can trade their ownership stakes similarly to how corporate stock is traded in a market. An MLP comprises two types of partners: (1) the limited partners (LPs), which provide the MLP with capital and periodically receive income distributions from it, and (2) the general partner (GP), which manages the MLP and is compensated for its performance. For an MLP’s structure to apply to limited partnerships, at least 90 percent of its cash flows must be derived from real estate, natural resources, and commodities.

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4 The final rule identifies the following five location restrictions: (1) placement above the uppermost aquifer, (2) wetlands, (3) fault areas, (4) seismic impact zones, and (5) unstable areas.

5 The time frames for implementing the final rule's technical criteria vary by required activity and type of disposal site. Further, the implementation time frame is based on a "number of months after publication of [the] rule" in the Federal Register.
On April 24, 2013, Congress introduced the Master Limited Partnerships Parity Act (the “Act”), which would amend the Internal Revenue Code to include clean energy technologies within the MLP structure. Specific energy technologies that would qualify include wind, closed- and open-loop biomass, geothermal, solar, municipal solid waste, hydropower, marine and hydrokinetic, fuel cells, and combined heat and power. Other types of technologies that could qualify include various types of transportation fuels, such as cellulosic, ethanol, biodiesel, and algae-based fuels; energy-efficient buildings; electricity storage; carbon capture and storage; renewable chemicals; and waste-heat-to-power technologies. However, current MLPs and MLP structuring projects would not be affected by the Act.

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

**Yieldcos**

A yieldco is a new structuring arrangement available to renewable energy companies under which a subsidiary is created to hold assets with steady cash flow streams. As with an MLP, a yieldco is initially established by one or more sponsors and the entity’s shares are subsequently offered to the public.

However, yieldcos are not as tax-efficient as MLPs because they constitute corporations rather than partnerships and are therefore subject to double taxation. However, the underlying assets of a yieldco generate tax credits (e.g., PTCs or ITCs) as well as accelerated depreciation (including bonus depreciation) for tax purposes. As a result of these tax attributes, there could be minimal taxable income at the yieldco level during the first several years of operations.

In a yieldco structure, a high percentage of dividend profits is distributed to shareholders and additional cash is solicited to fund future growth. Although yieldcos generally do not develop projects, they are afforded future growth opportunities through right-of-first-offer agreements with parent companies. Although yieldcos have been mostly used in the renewable energy arena, they may also apply to steady-earnings assets in other P&E areas, such as transmission and distribution.

Companies that have formed yieldcos during 2014 include:

- NextEra Energy Inc. — NextEra Energy Partners LP.
- SunEdison Inc. — TerraForm Power Inc.
- Pattern Development — Pattern Energy Group.
- Abengoa SA — Abengoa Yield.

**Real Estate Investment Trusts**

On May 9, 2014, the U.S. Department of the Treasury issued proposed regulations that would allow certain solar developments to qualify for inclusion in REITs. The proposed regulations could introduce new capital to the solar industry, since solar systems would be considered “real property” depending on certain factors.

Many entities in the renewables industry have been disappointed about the narrow scope of the proposed regulations, which effectively exclude utility-scale solar projects from qualifying as real property. However, one industry sector that could benefit from the proposed regulations is electric transmission. Transmission assets are attractive for formation of REITs since they usually provide steady income that allows for payment of dividends to investors. However, sponsoring utilities may need to consider potential reactions from regulators, since the formation of REITs is not commonplace for electric or gas utilities.
Changes in the U.S. Electric Industry

Profound changes to the traditional U.S. electric industry are not just inevitable; they are already occurring. The question is no longer if, but where and how fast. Such changes include the requirement for an entity to be “environmentally responsible” to have a license to do business, the emergence of proven new technologies, and the prevalence of established new market entrants with different models that are just waiting to scale their businesses. In addition, substantial investments in traditional electricity infrastructure for the sake of reliability are likely to have long-term implications without ensuring increases in kWh sales.

The evolving electric industry will experience, maybe in a relatively short time frame, a blurring of the line between offensive and defensive strategies. This blurring is likely to occur primarily in the distribution system, with more and more electricity generation being shifted to distributed networks located near the source of consumption — as close as the rooftop, basement, garage, or closet.

As a result, the distribution system’s role may well transition to one of ensuring reliability as a network manager, even at a local level. In this new role, the distribution utility will be responsible for managing both variable supply and variable demand in a manner that achieves maximum energy efficiency. Such a utility may well operate on both sides of the meter, continuing to own the transmission and distribution assets “up to the meter” and, potentially, the distributed generation and storage behind it.

In light of such profound changes, and given the critical role of electricity in Americans’ everyday lives, a smooth industry transition is essential for electric companies, their shareholders, and consumers. Stakeholders will need to develop a plan for achieving the paramount end objective — safe, reliable, affordable, and environmentally responsible electricity.

For more information about changes in the U.S. electric industry, see Deloitte’s The New Math — Solving the Equation for Disruption to the U.S. Power Industry.

Mexican Energy Reform

Since the 1930s, the Federal Commission of Electricity (CFE) has dominated Mexico’s electricity sector by providing generation, transmission, and distribution services to the entire country. Though the CFE has made great strides in expanding service and standardizing voltage and frequency, it has remained a vertically integrated monopoly with extremely limited access to capital to invest in the required generation and transmission infrastructure. Given its current generation fleet, the CFE has been forced to use more expensive oil, diesel, and other fuel sources to power its plants, keeping its generation costs relatively high. These higher costs have limited the ability of Mexico’s industries to be competitive and have hurt consumers, who would most likely use more appliances and devices if the costs were lower.

While minor reforms were implemented in the 1990s to partially open the generation market, they have proven to be insufficient. However, recent reforms, initiated by President Enrique Peña Nieto and adopted by Mexico’s Congress, dwarf earlier efforts and may dramatically reshape the P&U sector in Mexico.

Under the new reforms, the Mexican government continues to have exclusive ownership of underground hydrocarbons; however, foreign contracts to explore for, develop, and produce hydrocarbons are now permitted. As a result, service agreements between the government and private companies have become more competitive and now include profit-sharing arrangements, production-sharing hydrocarbon licenses, or a combination of both. Because hydrocarbons are now at the wellhead, the contracts can change ownership and private companies will be able to reflect these contracts and the related benefits in their financial statements (e.g., when reporting oil and gas production). SENER, the Secretariat of Energy, and the National Hydrocarbon Commission will control the bidding process, which should increase transparency and result in decisions that are primarily related to economics. The Energy Regulatory Commission will control the downstream process related to permits.
The Nexus of Water and Energy

Energy and water are inseparable. Increasing demands on water from the private and public sectors are affecting the world’s ability to meet its energy needs, since water is used to extract, process, and produce many forms of energy. Likewise, it takes vast amounts of energy to extract, transport, and treat water for agricultural, industrial, and domestic purposes. This interplay of supply and demand, which is often described as the water-energy — or energy-water — nexus, is illustrated in the diagram below.6

From an energy perspective, balancing the supply-demand equation involves reducing water consumption in traditional energy production as well as moving toward energy sources that are inherently less water-intensive. Technological advances are increasingly making both of these objectives possible. New methods of “dry cooling” — in which air-cooled condensers are used instead of conventional cooling towers — and water reuse and recycle schemes are giving traditional power producers new opportunities to reduce the quantity of water they need to withdraw as well as to improve its quality before discharge or evaporation. Meanwhile, water-access challenges for some forms of renewable energy, such as biofuels and solar thermal, are similar to those of their fossil-fuel counterparts, while others have negligible water footprints. Wind power and solar photovoltaics, in particular, fit this bill, which gives them an advantage that could trump cost per megawatt in certain high-stress regions.

For more information about the water-energy nexus, see Deloitte’s No Water, No Energy — No Energy, No Water.

Integrated Marketplaces

Expected benefits of integrated marketplaces include improved grid reliability through determination of which generating units should run the next day, improvements in regional balancing of supply and demand, and further integration of renewable resources into the market. Organizations that have implemented integrated marketplaces include the following:

- **Southwest Power Pool Inc. (SPP)** — On March 1, 2014, SPP, a regional transmission organization (RTO), implemented its integrated marketplace after FERC approval of its certificate of readiness on February 26, 2014. The integrated marketplace replaced SPP’s energy imbalance service market. SPP’s energy market is similar to markets operated by the Midcontinent Independent System Operator Inc. and PJM Interconnection LLC (PJM), but there are several distinctions to accommodate regional differences. SPP’s energy market offers a day-ahead energy and operating reserve market, a real-time balancing market, a market-based congestion management process, and market monitoring and mitigation by an internal market monitor. The launch of the integrated marketplace consolidated the 16 balancing-area authorities in the region into a single balancing-area authority operated by SPP. The SPP RTO region covers 370,000 square miles of service territory in Arkansas, Louisiana, Mississippi, Missouri, Nebraska, New Mexico, Oklahoma, and Texas.

- **California Independent System Operator (CAISO) and PacifiCorp** — On October 1, 2014, CAISO and PacifiCorp launched the Western U.S. Energy Imbalance Market (EIM). During October 2014, CAISO’s and PacifiCorp’s EIM systems interacted to give grid managers an opportunity to assess real-time operational data before November 1, 2014, the date on which the integrated marketplace became fully operational and financially binding. The EIM currently involves balancing areas in six western states (part of California, Oregon, Washington, Utah, Idaho, and Wyoming) and uses an automated system that balances electricity supply and demand every five minutes. The market is designed to identify the most efficient resources over a wider geographical area, reducing electricity costs while enhancing reliability by employing a larger pool of resources to manage the grid. CAISO has also announced that it will publish quarterly reports documenting the aggregated benefits to each balancing authority in the EIM. The first report will be published in January or February of 2015 by using real-time market data.

- **Northwest Power Pool initiative** — Launched in March 2012 and led by the Market Assessment and Coordination Committee (the “Committee”), which comprises 16 balancing-area authorities and three scheduling entities, the Northwest Power Pool initiative proposes an automated security-constrained economic dispatch (SCED) based on five-minute energy dispatch cycles. The SCED is similar in design and concept to CAISO and PacifiCorp’s EIM. The ultimate decision about the formation of SCED is expected to be made in the third quarter of 2015 but, before this time, the Committee will file for a declaratory order with FERC regarding the design of SCED. To date, no balancing-area authority has agreed to join the Northwest Power Pool.

Shale Gas and Liquefied Natural Gas

According to a report by the International Monetary Fund (IMF), *World Economic Outlook: Legacies, Clouds, Uncertainties*, the shale gas revolution has been one of the most significant factors to affect global natural gas and energy markets over the past several years. The growth in U.S. natural gas production has (1) made international energy prices much more stable, (2) led to a flurry of proposed U.S. natural gas export projects, and (3) boosted U.S. competitiveness. At the same time, this growth has led to a decline in U.S. fossil fuel imports from $412 billion in 2008 to $225 billion in 2013.
The shale gas revolution has helped stabilize natural gas prices, but there could be more volatility on the horizon for the natural gas market as it continues to seek a sustainable balance between supply and demand. While natural gas prices are still low, they have increased to an average of $4.59 per MMBtu (Henry Hub Natural Gas Index SNL) for the first nine months of 2014 compared with an average of $3.69 per MMBtu (Henry Hub Natural Gas Index SNL) for the first nine months of 2013. These average natural gas prices are still substantially lower than the average of $9.70 (Henry Hub Natural Gas Index SNL) for the first nine months of 2008.

Thus far, the shale gas revolution has more significantly affected the supply side, but it is starting to affect the demand side as well. Factors that are bolstering the demand for natural gas include increased exports to Mexico, liquefied natural gas (LNG) exports, and regulation-induced coal-to-gas switching. The amount of exports to Mexico has been steadily increasing, and this trend should continue for some time as the nation overhauls its energy industry (see discussion in Mexican Energy Reform above). According to the EIA data updated in April 2014, natural gas exports to Mexico accounted for more than 38 percent of total natural gas exports and approximately 80 percent of Mexico’s natural gas imports in 2012.

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

FERC must approve the construction and operation of LNG export facilities, while the U.S. Department of Energy (DOE) must authorize exports to nations that do not adhere to free trade agreements, such as Japan, India, and the United Kingdom. As of November 14, 2014, the DOE has received 43 applications for authorization of exports to nations that operate under free trade agreements and has approved 39 of them. In addition, the DOE has received 36 applications for authorization of exports to nations that do not operate under free trade agreements and has issued final approval for five and conditionally approved four:

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<th>Applications That Have Received Final Approval</th>
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<td>Sabine Pass Liquefaction LLC (a subsidiary of Cheniere Energy Inc.) — FERC approval granted on April 16, 2012; began constructing four liquefaction trains in August 2012, with the first train expected to produce LNG by late 2015; the other three trains are expected to become operational from 2016 to 2017.</td>
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<td>Cameron LNG LLC — FERC approval granted on June 19, 2014; expected to begin constructing the three liquefaction trains by the end of 2014 and become operational in 2018.</td>
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<tr>
<td>Carib Energy (USA LLC) (a subsidiary of Crawley Maritime Corp.) — No FERC approval needed because project does not involve construction of an LNG export terminal.</td>
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<td>Two approvals for Freeport LNG Expansion LP and FLNG Liquefaction LLC (subsidiaries of Freeport LNG Development LP) — FERC approval granted on July 30, 2014, and FERC approval pending, respectively.</td>
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<th>Applications That Have Received Conditional Approval</th>
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<td>Dominion Cove Point LNG LP (a subsidiary of Dominion Resources Inc.) — FERC approval granted on September 29, 2014; began construction-related activities for the LNG terminal on October 30, 2014, and is expected to begin operations in late 2017.</td>
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<tr>
<td>Lake Charles Exports LLC — FERC approval pending.</td>
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<tr>
<td>Jordan Cove Energy Project LP (a subsidiary of Veresen Inc.) — FERC approval pending.</td>
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<tr>
<td>LNG Development Company LLC (d/b/a Oregon LNG) — FERC approval pending.</td>
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As of October 14, 2014, there is a total of 14 LNG export projects for which formal applications are pending FERC approval. Two of these projects are located in the Pacific Northwest, one in the Northeast, and 11 in the Southeast.

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

On October 29, 2014, the EIA issued a report to the DOE on the economic impact of LNG exports in response to the DOE’s request earlier in 2014 to update the last study the EIA prepared for the DOE. The report indicates that if LNG exports ramp up at a quicker pace than federal studies are expecting, the natural gas market will be able to adjust without negatively affecting the economy. According to the report, exports will slightly raise natural gas prices in the United States, driving producers to increase their volumes of gas and consumers to cut their usage. However, the EIA does not expect such a scenario to play out, calling the possibility of 12 Bcf/d of exports by 2020 “extremely aggressive.”
Distributed Generation

Distributed generation (DG) can be defined as electricity generation in which the customer generates electricity on site rather than purchasing it from a local utility. Use of DG is on the rise because of its lower costs and the government subsidies that often support it. DG technologies often consist of modular generators such as solar photovoltaic (PV) systems, combined heat and power systems, and microgrids. Solar PV systems are a particularly popular form of DG because they are becoming cheaper to purchase and install.

In the debate over utility ratemaking in the era of DG, individuals in certain industry sectors and customer groups are making a case for avoiding paying a share of the costs that are necessary for maintaining a reliable power system in each U.S. state and throughout the nation. The current debate is reminiscent of that related to the electric industry restructuring in the 1990s, when electric utilities’ nuclear- and coal-generating portfolios were viewed as stranded assets and many states passed legislation requiring that these portfolios be divested. Many states have begun to see that their rate structures are promoting DG in ways that make it difficult for electric utilities to recover transmission and distribution costs.

To address the potential disconnect between an evolving grid and stagnant pricing models, various stakeholders in the electric utility industry are calling for more sophisticated rate design for residential and small commercial customers. In its August 26, 2014, report, “Rate Design for the Distribution Edge: Electricity Pricing for a Distributed Resource Future,” the Rocky Mountain Institute (RMI) discusses the possibility of transitioning from volumetric block rates to more “granular” pricing that accounts for the costs and benefits of DG (i.e., the new structure would take into account the impact of delivering power back to the grid). RMI’s report also suggests unbundling rates to separately price energy, capacity, and ancillary services; moving in the direction of time-differentiated pricing; and establishing prices that reflect site-specific value.

Many of the current rate structures are incompatible with the widespread adoption of DG and present electric utilities with financial challenges. This incompatibility is most evident with net metering programs. In net metering, customers can exchange surplus kWh of electricity they produce on DG technologies during the day for grid-produced kWh at night. This mechanism may allow some customers to zero-out their monthly bills and shift an added burden onto non-DG customers for paying electric utilities’ fixed costs.

Some examples of regulators dealing with DG include:

- **California Public Utility Commission** — Issued a rule under which nonutility-owned energy resources are incorporated into the planning and operation of electric distribution systems.
- **Colorado Public Utility Commission** — Can approve separate rate classes for net-metered customers, provided that the rates are reasonably justified.
- **New York Public Service Commission** — Has begun an effort to modernize the grid and give consumers more control (e.g., through its regulation of electric utilities).
- **Minnesota Public Utility Commission** — Approved a method in March 2014 for calculating the value of DG associated with solar energy; this approach could replace net metering.

The Edison Electric Institute (EEI) identified the increasing impact of DG and associated net metering policies on the grid as a key issue for the electric utility sector in 2014. Many net metering programs are structured so that ratepayers using rooftop solar, who rely on the grid 24 hours a day, pay less for the costs of the grid than they did before their systems were installed despite their continued reliance on the grid and its services.

The Critical Consumer Issues Forum (CCIF), which comprises representatives from the National Association of Regulatory Utility Commissioners (NARUC), the National Association of State Utility Consumer Advocates (NASUCA), and the EEI, has released a set of 21 consensus principles related to distributed energy resources. The principles, which serve as a framework for policymakers and stakeholders who evaluate the technology’s benefits and challenges, cover four main topics:

- Financial and regulatory concerns.
- Market development and deployment.
• Consumer issues.
• Safety, reliability, and system planning.

The principles also touch on such issues as subsidization and reliability.

**Cybersecurity**

**Cybersecurity Executive Order**

On February 12, 2013, President Obama issued an executive order on cybersecurity to communicate the “policy of the United States to enhance the security and resilience” of the nation’s critical infrastructure and protect it from cyberthreats. The order’s requirements include (1) more timely sharing of cyberthreat-related information between U.S. government agencies and with private-sector companies; (2) development of a “baseline” framework to reduce cybersecurity risks; (3) establishment of a voluntary critical infrastructure cybersecurity program to support the adoption of the cybersecurity framework; and (4) identification of the critical infrastructure that is subject to the greatest risk.

On its Web site, the Department of Homeland Security (DHS) identifies 16 critical infrastructure sectors and, for each sector, provides a summary, a sector-specific plan, and other resources. According to the DHS, the energy sector has been identified as “uniquely critical” because it provides “enabling functions . . . across all critical infrastructure sectors.” The energy infrastructure comprises three interrelated segments: electricity, petroleum, and natural gas.

According to the DHS, the energy sector is “aware of its vulnerabilities and is leading a significant voluntary effort to increase its planning and preparedness.” For instance, the North American Electric Reliability Corp. (NERC) is proposing a budget increase for 2015 and is focusing on the Cybersecurity Risk Information Sharing Program (CRISP), a new automated program to help utilities identify and thwart attacks. Most of the additional costs associated with CRISP will be paid for by entities that participate in the program.

**NIST Framework**

In response to President Obama’s executive order, the National Institute of Standards and Technology (NIST) released the first version of its cybersecurity framework in February 2014. The framework outlines what NIST believes is a strategic, cost-effective approach to managing cybersecurity-related risks. According to NIST, the framework “focuses on using business drivers to guide cybersecurity activities and considering cybersecurity risks as part of [an] organization’s risk management processes.” The framework is intended for use by all companies, regardless of their size or complexity, and contains risk management principles (and best practices) that would allow companies to improve “the security and resilience of critical infrastructure.” However, NIST cautions companies that the framework is not a “one-size-fits-all” approach for dealing with cybersecurity risks.

**Cybersecurity Landscape**

Cyberthreats may affect not only technology but also an entity’s broader operations. Mary Galligan, director of Cyber Risk Services at Deloitte & Touche LLP, has outlined a three-pronged “threat matrix”: (1) threat vectors, (2) threat intelligence, and (3) threat resiliency. Threat vectors encompass cyberattack perpetrators and the reasons for their attacks. Threat intelligence involves an acknowledgment that securing data is not sufficient and that information sharing with governmental and other private-sector parties is also needed. Threat resiliency — or an entity’s ability to quickly identify, remediate, and recover from incidents — is critical because a cyberattack often increases the risk of other threats. Such additional threats include disruption of an entity’s daily business operations, damage to its reputation (not only from the attack itself but from public reception of the entity’s disclosures about the attack), and the costs of responding to and remediating a cyberattack.

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7 The executive order defines critical infrastructure as “systems and assets, whether physical or virtual, so vital to the United States that the incapacity or destruction of such systems and assets would have a debilitating impact on security, national economic security, national public health or safety, or any combination of those matters.”
Cybersecurity risk cannot be addressed by a one-time IT solution but must be evaluated on an ongoing basis. In addition, companies need to attempt to mitigate cybersecurity risks in a manner similar to other business risks. Consequently, companies must continually evaluate their vulnerabilities related to business processes and key systems. Given companies’ limited resources and the scarcity of cybersecurity resources, companies should concentrate on the most vulnerable aspects of their operations rather than focusing too broadly on systemic risk.

For more information about the cybersecurity landscape, see Deloitte’s April 8, 2014, Heads Up.

Physical Security

NERC has an active project, “CIP-014-1 — Physical Security,” to address the directives in FERC’s March 7, 2014, order related to the filing of its Reliability Standards for Physical Security Measures. The order states:

As part of its ongoing oversight of the Bulk-Power System, and pursuant to section 215(d)(5) of the Federal Power Act (FPA), the Commission directs [NERC], as the Commission-certified Electric Reliability Organization (ERO), to submit for approval one or more Reliability Standards that will require certain registered entities to take steps or demonstrate that they have taken steps to address physical security risks and vulnerabilities related to the reliable operation of the Bulk-Power System. The proposed Reliability Standards should require owners or operators of the Bulk-Power System, as appropriate, to identify facilities on the Bulk-Power System that are critical to the reliable operation of the Bulk-Power System. Then, owners or operators of those identified critical facilities should develop, validate and implement plans to protect against physical attacks that may compromise the operability or recovery of such facilities. The Commission directs NERC to submit the proposed Reliability Standards to the Commission within 90 days of the date of this order.

Furthermore, the order describes the purpose and industry need for the project as follows:

Physical attacks to the Bulk-Power System can adversely impact the reliable operation of the Bulk-Power System, resulting in instability, uncontrolled separation, or cascading failures. However, the current Reliability Standards do not specifically require entities to take steps to reasonably protect against physical security attacks on the Bulk-Power System. Therefore, to carry out section 215 of the FPA and to provide for the reliable operation of the Bulk-Power System, the Commission directs the ERO to develop and file for approval proposed Reliability Standards that address threats and vulnerabilities to the physical security of critical facilities on the Bulk-Power System. Such Reliability Standards will enhance the Commission’s ability to assure the public that critical facilities are reasonably protected against physical attacks. [Footnote omitted]

The NERC’s proposed standard based on FERC’s order was submitted to NERC members for voting from May 1 to May 5, 2014, and the proposed standard was approved on May 6, 2014. The NERC board of trustees adopted CIP-014-1 at its May 13, 2014, meeting, and FERC approved the standard on November 20, 2014.

FERC Developments

Order 1000

In the summary of Order 1000 on its Web site, FERC states that the objective of the standard is to reform the “electric transmission planning and cost allocation requirements for public utility transmission providers.” The rule creates three transmission-planning requirements:

• “Each public utility transmission provider must participate in a regional transmission planning process that satisfies the transmission planning principles of Order No. 890 and produces a regional transmission plan.”

• “Local and regional transmission planning processes must consider transmission needs driven by public policy requirements established by state or federal laws or regulations. Each public utility transmission provider must establish procedures to identify transmission needs driven by public policy requirements and evaluate proposed solutions to those transmission needs.”

• “Public utility transmission providers in each pair of neighboring transmission planning regions must coordinate to determine if there are more efficient or cost-effective solutions to their mutual transmission needs.”
Further, the order contains three requirements related to allocation of transmission costs:

- “Each public utility transmission provider must participate in a regional transmission planning process that has a regional cost allocation method for new transmission facilities selected in the regional transmission plan for purposes of cost allocation. The method must satisfy six regional cost allocation principles.”

- “Public utility transmission providers in neighboring transmission planning regions must have a common interregional cost allocation method for new interregional transmission facilities that the regions determine to be efficient or cost-effective. The method must satisfy six similar interregional cost allocation principles.”

- “Participant-funding of new transmission facilities is permitted, but is not allowed as the regional or interregional cost allocation method.”

In addition, “[p]ublic utility transmission providers must remove from Commission-approved tariffs and agreements a federal right of first refusal for a transmission facility selected in a regional transmission plan for purposes of cost allocation.” However, there are four exceptions to this requirement:

- The requirement “does not apply to a transmission facility that is not selected in a regional transmission plan for purposes of cost allocation.”

- Providers in a transmission planning region are permitted, but not required, “to use competitive bidding to solicit transmission projects or project developers.”

- State and local regulations related to the construction of transmission facilities are unaffected by this requirement. Such regulations include, but are not limited to, those associated with “authority over siting or permitting of transmission facilities.”

- “[I]ncumbent transmission providers may rely on regional transmission facilities to satisfy their reliability needs or service obligations.” However, public utility transmission providers are required to amend their tariffs “to require reevaluation of the regional transmission plan to determine if delays in the development of a transmission facility require evaluation of alternative solutions, including those proposed by the incumbent, to ensure incumbent transmission providers can meet reliability needs or service obligations.”

One of the most controversial aspects of the order was the requirement to remove from Commission-approved tariffs and agreements the right-of-first-refusal to build new transmission facilities. FERC ruled that utilities must compete with others for the right to build those facilities. Forty-five parties asked the U.S. Court of Appeals for the District of Columbia Circuit to review various aspects of the order in South Carolina Public Service Authority et al. v. FERC.

On August 15, 2014, the court of appeals rejected the pleas to overturn the order, arguing that FERC did not encroach on states’ authority in imposing regional transmission cost allocation and planning requirements. Moreover, the court believed that FERC had adequately justified its decision to remove the right-of-first-refusal. The court also upheld the rule’s requirement for jurisdictional utilities to participate in regional and interregional grid-planning processes.

Despite the removal of the right-of-first-refusal, a new report from Moody’s is predicting that such utilities will still end up building many of the new projects in their own service territories, since they will continue to have a competitive edge when bidding for such projects unless their relationships with state regulators have been strained. The incumbent utilities are well positioned to win competitive bids because of their expertise, technological know-how, and experience with such bidding.

**Formula Rate Standards**

On July 17, 2014, FERC released a paper that provides guidance on how utilities should update their transmission formula rates to ensure that they are just and reasonable. In separate orders that FERC also issued on July 17, 2014, the Commission directed two utilities to propose formula rate protocols and four utilities to revise their protocols or explain why such revision should not be required. Specifically, FERC directed the utilities to revise or provide formula rate protocols that (1) allow a broader range of interested parties to obtain formula rate information and participate in review processes; (2) boost transparency by making revenue requirements, cost inputs, calculations, and other information publicly available;
and (3) detail the procedures that interested parties can use to both informally and formally challenge the implementation of the formula rates.

The paper also states that FERC is requiring utilities to share annual updates to their formula rates “with all interested parties and to file [the] updates with the Commission on an informational basis.”

The FERC staff has identified certain common deficiencies in these updates. The paper indicates that utilities can “avoid common deficiencies” by ensuring that updates (1) are presented in a format that complies with FERC requirements stipulated in the guidance and (2) sufficiently support all inputs “so that interested parties can verify that each input is consistent with the requirements of the [rate] formula.”

Method for Determining Return on Equity

In a June 19, 2014, press release, FERC announced that it has adopted a new discounted cash flow method “for determining the rate of return on equity (ROE) for Commission-jurisdictional electric utilities.” The press release notes that the new method is the same as that used “for natural gas and oil pipeline ROEs: incorporating both short-term and long-term measures of growth in dividends.”

FERC applied the method to a pending complaint involving the ROE of New England Transmission Owners (NETOs), as detailed in the Commission’s Opinion 531. The press release notes that FERC has established “a paper hearing on the appropriate long-term growth rate to use, noting that in natural gas and oil pipeline proceedings [the Commission] uses growth in GDP as a measure of long-term growth.” The purpose of the paper hearing is to give the ruling’s participants “an opportunity to submit briefs on an issue regarding the application [of the new approach] to the facts of this proceeding.”

On the basis of this hearing, FERC released Opinion 531-A on October 16, 2014. In this order, FERC cuts the base rate of the NETOs’ ROE from 11.14 percent to 10.57 percent, finding that the existing rate was unjust and unreasonable. The new base ROE is effective immediately, and FERC has ordered the NETOs to provide refunds with interest for the period from October 1, 2011, through December 31, 2012.

Opinion No. 531-A constitutes FERC’s ruling on only one of three complaints challenging the NETOs’ base ROE, as reflected in ISO New England Inc.’s open-access transmission tariff.

The two other complaints were submitted in December 2012 and July 2014. FERC consolidated these two hearings but established two separate 15-month refund periods between December 27, 2012, and March 27, 2014. The hearing for this consolidated complaint is set to begin on June 8, 2015.

Other recent FERC orders related to this topic include the following:

- **EL14-86** — On November 24, 2014, FERC issued an order establishing a “trial-type, evidentiary hearing” related to a new complaint seeking to reduce the NETOs’ ROE even further. FERC consolidated this hearing with another pending complaint challenging the ROE. The refund effective date for the new complaint is July 31, 2014.

- **EL14-12** — On October 16, 2014, FERC issued an order establishing a “hearing and settlement judge procedures” related to a complaint seeking to reduce the existing 12.38 percent base ROE earned by most Midcontinent Independent System Operator Inc. transmission organizations to no more than 9.15 percent. This complaint also argues that the current ROE does not “reflect current capital market conditions.”

Market Prices

On its Web site, the EIA points out that “the United States has many regional wholesale electricity markets” and that “[w]holesale electricity prices are closely tied to wholesale natural gas prices in all but the center of the country.” The correlation between natural gas and electricity prices is strong enough that the prices usually rise and fall in tandem. With respect to wholesale natural gas prices, the main pricing point in the United States is Henry Hub in Louisiana.
Below is a table summarizing current and historical average wholesale electricity prices (on-peak and off-peak) for CAISO, Electric Reliability Council of Texas (ERCOT), ISO New England (ISO-NE), Midcontinent ISO (MISO), New York ISO (NYISO), PJM, and SPP. Also included is a summary of current and historical average wholesale natural gas prices for Henry Hub. The average wholesale electricity prices and wholesale natural gas prices are calculated by using SNL ISO day-ahead on-peak/off-peak prices and SNL day-ahead natural gas prices, respectively.

### SNL ISO Day-Ahead — On Peak Prices

<table>
<thead>
<tr>
<th>Date</th>
<th>CAISO Average</th>
<th>ERCOT Average</th>
<th>ISO-NE Average</th>
<th>MISO Average</th>
<th>NYISO Average</th>
<th>PJM Average</th>
<th>SPP Average</th>
</tr>
</thead>
<tbody>
<tr>
<td>First nine months of 2014</td>
<td>51.90</td>
<td>50.01</td>
<td>85.99</td>
<td>49.56</td>
<td>76.71</td>
<td>63.46</td>
<td>40.70</td>
</tr>
<tr>
<td>2013</td>
<td>44.89</td>
<td>38.16</td>
<td>64.72</td>
<td>38.36</td>
<td>54.36</td>
<td>42.20</td>
<td>N/A</td>
</tr>
<tr>
<td>2012</td>
<td>32.55</td>
<td>35.48</td>
<td>41.88</td>
<td>33.50</td>
<td>42.15</td>
<td>37.19</td>
<td>N/A</td>
</tr>
<tr>
<td>2011</td>
<td>36.21</td>
<td>61.48</td>
<td>52.84</td>
<td>39.24</td>
<td>52.60</td>
<td>47.50</td>
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<tr>
<td>2010</td>
<td>39.51</td>
<td>N/A</td>
<td>56.06</td>
<td>40.18</td>
<td>55.12</td>
<td>48.29</td>
<td>N/A</td>
</tr>
<tr>
<td>2009</td>
<td>37.43</td>
<td>N/A</td>
<td>46.27</td>
<td>34.15</td>
<td>46.35</td>
<td>40.21</td>
<td>N/A</td>
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<td>2008</td>
<td>N/A</td>
<td>N/A</td>
<td>90.99</td>
<td>66.21</td>
<td>91.78</td>
<td>75.25</td>
<td>N/A</td>
</tr>
</tbody>
</table>

### SNL ISO Day-Ahead — Off Peak Prices

<table>
<thead>
<tr>
<th>Date</th>
<th>CAISO Average</th>
<th>ERCOT Average</th>
<th>ISO-NE Average</th>
<th>MISO Average</th>
<th>NYISO Average</th>
<th>PJM Average</th>
<th>SPP Average</th>
</tr>
</thead>
<tbody>
<tr>
<td>First nine months of 2014</td>
<td>41.85</td>
<td>33.76</td>
<td>60.91</td>
<td>35.07</td>
<td>50.19</td>
<td>39.52</td>
<td>27.77</td>
</tr>
<tr>
<td>2013</td>
<td>36.30</td>
<td>28.25</td>
<td>48.76</td>
<td>30.37</td>
<td>38.99</td>
<td>30.47</td>
<td>N/A</td>
</tr>
<tr>
<td>2012</td>
<td>23.59</td>
<td>22.13</td>
<td>31.39</td>
<td>23.54</td>
<td>30.54</td>
<td>27.03</td>
<td>N/A</td>
</tr>
<tr>
<td>2011</td>
<td>22.41</td>
<td>31.06</td>
<td>40.67</td>
<td>26.15</td>
<td>39.95</td>
<td>33.35</td>
<td>N/A</td>
</tr>
<tr>
<td>2010</td>
<td>30.00</td>
<td>N/A</td>
<td>42.29</td>
<td>25.82</td>
<td>41.38</td>
<td>34.32</td>
<td>N/A</td>
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<tr>
<td>2009</td>
<td>26.91</td>
<td>N/A</td>
<td>37.12</td>
<td>20.93</td>
<td>34.90</td>
<td>29.64</td>
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<td>2008</td>
<td>N/A</td>
<td>N/A</td>
<td>71.17</td>
<td>33.35</td>
<td>67.93</td>
<td>48.00</td>
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</tr>
</tbody>
</table>

### SNL Day-Ahead Natural Gas Prices

<table>
<thead>
<tr>
<th>Date</th>
<th>Henry Hub Average</th>
</tr>
</thead>
<tbody>
<tr>
<td>First nine months of 2014</td>
<td>4.59</td>
</tr>
<tr>
<td>2013</td>
<td>3.73</td>
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<tr>
<td>2012</td>
<td>2.76</td>
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<tr>
<td>2011</td>
<td>4.00</td>
</tr>
<tr>
<td>2010</td>
<td>4.37</td>
</tr>
<tr>
<td>2009</td>
<td>3.94</td>
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<tr>
<td>2008</td>
<td>8.90</td>
</tr>
</tbody>
</table>
Section 2
SEC Update
Disclosure Effectiveness

In December 2013, in a report made in response to a JOBS Act mandate, the SEC staff indicated that the Commission would commence a broad effort to modernize and streamline its rules and regulations (i.e., the SEC’s “disclosure effectiveness project”). To achieve this objective, the SEC will focus not only on eliminating outdated, redundant, and overlapping disclosures but also on identifying topics about which investors may need better or more information to make educated investment decisions.

In 2014, Keith Higgins, director of the SEC’s Division of Corporation Finance, noted that the SEC staff will identify ways to improve the disclosure requirements in Regulations S-K and S-X. The staff will analyze Regulation S-K as part of the first phase of its disclosure effectiveness project, focusing “on the business and financial disclosures that flow into periodic and current reports, namely Forms 10-K, 10-Q, and 8-K, and, in one way or another, make their way into transactional filings.”

In addition, the staff has remarked on how, in the absence of rule changes, registrants can improve their disclosures in the near term — notably, by focusing on matters that are material and relevant to their operations, liquidity, and financial condition.

See Deloitte’s August 26, 2014, Heads Up for more information about the disclosure effectiveness initiatives that are currently underway and October 16, 2014, Heads Up for more information about changes that registrants can make now to provide effective disclosures.

Activities Related to Requirements Under the Dodd-Frank Act

The passage of the Dodd-Frank Act in July 2010 brought a number of key reforms to the U.S. financial system. The Dodd-Frank Act requires the SEC to perform certain actions, such as adopting rules or conducting studies. The discussion below summarizes Dodd-Frank Act activity that has occurred since the last edition of this publication.

Navigating the Conflict Minerals Rule

There is ongoing legal action against the SEC regarding the constitutionality of certain disclosure requirements in its final rule on conflict minerals (i.e., tin, tantalum, tungsten, or gold). In April 2014, the U.S. Court of Appeals for the District of Columbia Circuit held that parts of the final rule and of Section 1502 of the Dodd-Frank Act violate the First Amendment to the extent that they require “regulated entities to report to the Commission and to state on their website that any of their products have ‘not been found to be DRC conflict-free.’” Thus, although registrants are still expected to file Form SD and, if applicable, a conflict minerals report (CMR) required by the rule on or before the due date, they are not required to identify any products as “not found to be DRC conflict free” or “DRC conflict undeterminable.” Registrants could still elect to identify products as “DRC conflict free”; however, they would be required to obtain an independent private-sector audit (IPSA) in such cases.

On June 2, 2014, the SEC petitioned the U.S. Court of Appeals for the D.C. Circuit for another judicial hearing regarding the constitutionality of certain conflict minerals disclosures.

More than 1,300 registrants submitted their first conflict minerals filing in early June 2014. Of these registrants, 4 percent were from the energy and resources industry, 78 percent included a CMR as an exhibit to their Form SD, and only four had an IPSA performed.

For more information about the SEC’s final rule on conflict minerals and the related legal proceedings, see Deloitte’s July 21, 2014, and March 27, 2014, Heads Up newsletters.
Security-Based Swaps

On February 7, 2014, the SEC published amendments extending the expiration date for “interim final rules that provide exemptions under the Securities Act of 1933, the Exchange Act of 1934, and the Trust Indenture Act of 1939 for those security-based swaps that [1] prior to July 16, 2011 were security-based swap agreements and [2] are defined as ‘securities’ under the Securities Act and the Exchange Act as of July 16, 2011 due solely to the provisions of Title VII of the [Dodd-Frank Act].” The amendments affect the following interim final rules:

- Rule 240 of the Securities Act.
- Rules 12a-11 and 12h-1(i) of the Exchange Act.
- Rule 4d-12 of the Trust Indenture Act.

The new expiration date for the interim final rules is February 11, 2017.

Further, the SEC issued a proposed rule on April 17, 2014, that would revise the requirements for “security-based swap dealers and major security-based swap market participants” under the Exchange Act. The proposal is being issued in response to a mandate of the Dodd-Frank Act that “authorizes the SEC and other regulators to put in place a comprehensive framework to regulate the over-the-counter swaps and security-based swaps markets.” Comments on the proposed rule were due by July 1, 2014.

On June 26, 2014, the SEC also issued a final rule that explains “when a cross-border transaction must be counted toward the requirement to register as a security-based swap dealer or major security-based swap participant.” In addition, the final rule addresses “the scope of the SEC’s cross-border anti-fraud authority.” The final rule became effective on September 8, 2014.

SEC Adopts Money Market Fund Reforms

On July 23, 2014, the SEC adopted a final rule on money market fund (MMF) reform. The final rule retains the SEC’s proposal to eliminate the use of penny rounding for institutional nongovernment MMFs and establishes a current net asset value (NAV) — or floating NAV — like that used in other mutual funds. In addition, government and retail MMFs may continue using amortized cost to value a fund’s investments instead of calculating the fund’s value by using a floating NAV (i.e., they may continue to use a stable NAV, which is typically $1). Municipal MMFs are not exempt from the floating rate requirement unless they meet the definition of a “retail” MMF. MMFs with floating NAVs will be permitted to “continue to use amortized cost to value debt securities with remaining maturities of 60 days or less if fund directors, in good faith, determine that the fair value of the debt securities is their amortized cost value, unless the particular circumstances warrant otherwise.”

The final rule also includes provisions related to redemption gates and liquidity fees. Under these provisions, an MMF will be permitted to “impose a liquidity fee of up to 2%, or temporarily suspend redemptions (also known as ‘gate’) for up to 10 business days in a 90-day period, if the fund’s weekly liquid assets fall below 30% of its total assets and the fund’s board of directors (including a majority of its independent directors) determines that imposing a fee or gate is in the fund’s best interests.” In addition, an MMF “will be required to impose a liquidity fee of 1% on all redemptions if its weekly liquid assets fall below 10% of its total assets, unless the board of directors of the fund (including a majority of its independent directors) determines that imposing such a fee would not be in the best interests of the fund.”

Other provisions of the final rule include requirements related to enhanced portfolio diversification, stress testing, disclosures, and financial reporting obligations. These regulations may affect registrants in the P&U sector. For instance, the final rule conveys the SEC’s belief that under normal market conditions, an investment in an MMF “that has the ability to impose a fee or gate” qualifies as a cash equivalent under U.S. GAAP. It also clarifies that if events occur that cause an MMF to impose liquidity fees or gates, “shareholders would need to reassess if their investments in [such an MMF continues] to meet the definition of a cash equivalent” under U.S. GAAP; however, the final rule does not provide guidance on how such a reassessment might be performed. The final rule also notes that the SEC declined to issue a “more formal pronouncement
(as requested by some commenters) to confirm [its] position . . . because the federal securities laws provide the Commission with plenary authority to set accounting standards, and [the SEC does so in the final rule].”¹

SEC Adopts Rules Related to Asset-Backed Securities and Credit Agency Rating Reform

On August 27, 2014, the SEC adopted a final rule that revises the disclosure, reporting, and offering process for asset-backed securities (ABSs), which are typically offered through securitization transactions. The objectives of the final rule are to increase transparency, enhance information for investors, and implement Section 942(b) of the Dodd-Frank Act. The new rule introduces or revises requirements related to (1) asset-level information, (2) prospectus filings, (3) replacement of credit ratings, and (4) changes to Regulation AB.

The Jumpstart Our Business Startups Act

The SEC continues to complete its rulemaking mandates under the JOBS Act.² Below is a summary of JOBS Act activity that has occurred since the last edition of this publication.

Small-Company Capital Formation

On December 18, 2013, the SEC issued a proposed rule (in response to a mandate in Section 401 of the JOBS Act) that would exempt offerings of securities under Regulation A (up to $50 million annually) from the registration requirements of the Securities Act. The proposed rule specifies (1) which issuers are eligible for the exemption, (2) the content and filing requirements for issuers’ offering statements, and (3) issuers’ ongoing reporting requirements.

The proposed rule would update and expand the exemption by creating two tiers of offerings under Regulation A:

• Tier 1 would consist of offerings that satisfy Regulation A’s current requirements.

• Tier 2 would consist of securities offered of up to $50 million in a 12-month period with no more than $15 million offered by an issuer’s securityholders.

In addition, the proposed rule describes types of issuers that would be ineligible to use Regulation A to offer their securities. For example, the exemption under Regulation A would not be available to companies that (1) are currently SEC-reporting companies or to those organized (or whose principal place of business is located) outside the United States or Canada, (2) have no specific business plan or purpose, or (3) are subject to disciplinary action by the SEC.

Comments on the proposed rule were due by March 24, 2013. For more information about the proposal, see Deloitte’s December 20, 2013, journal entry.

¹ See Section VI of the final rule for additional information.

² In April 2012, the JOBS Act was signed into law to increase American job creation and economic growth by improving access to the public capital markets for EGCs. The JOBS Act addresses topics such as “crowdfunding” transactions, increases shareholder limits that would require companies to register with the SEC, and provides accommodations to EGCs. See Deloitte’s April 15, 2014, Heads Up for additional information.
Incorporating IFRSs Into U.S. Financial Reporting System

At the AICPA Conference on Current SEC and PCAOB Developments in December 2014, SEC Chief Accountant James Schnurr discussed a possible fourth alternative for incorporating IFRSs into the U.S. financial reporting system. Under this potential alternative, U.S. companies would have the option of voluntarily providing IFRS-prepared financial information as a supplement to their U.S. GAAP financial statements. The information from this fourth alternative could range from selected IFRS financial information to full IFRS financial statements. Mr. Schnurr further noted that “[u]nder this line of thinking, issuers that do not believe IFRS-based information would be beneficial to investors would not be forced to undertake what we understand to be, in some cases, significant implementation costs.” The SEC is expected to solicit feedback on this approach in 2015. See Deloitte’s December 15, 2014, Heads Up for additional information about the potential alternative.

Other SEC Matters

Financial Reporting Manual Updates

During 2014, the SEC’s Division of Corporation Finance issued the following updates to its Financial Reporting Manual (FRM):

- **October 20, 2014, updates** — Notable changes include (1) the deletion of interpretive guidance on development-stage entities (for consistency with U.S. GAAP); (2) clarifications to the definition in Regulation S-X, Rule 3-05, of “individually insignificant acquisitions”; (3) modifications to certain guidance on applying Regulation S-X, Rule 3-14, to real estate acquisitions.

- **February 6, 2014, updates** — The most significant change concerns the guidance on MD&A disclosures about “cheap stock” in IPO transactions. The SEC staff updated the guidance in Section 9520 of the FRM on accounting for cheap stock (i.e., equity securities issued as compensation in periods before an IPO). The updated guidance clarifies that the staff may ask companies “to explain the reasons for valuations that appear unusual.” The SEC has encouraged registrants undergoing an IPO to make their disclosures about this topic more relevant while avoiding excessive detail. See Deloitte’s April 28, 2014, Heads Up for more information.

CAQ SEC Regulations Committee Meeting Highlights

The CAQ SEC Regulations Committee and SEC staff periodically meet to discuss various technical accounting and reporting matters, including (1) capital formation initiatives, (2) disclosure effectiveness, (3) current financial reporting matters, and (4) current practice issues. Highlights of the committee’s March 21, June 25, and September 23, 2014, meetings are available on the CAQ’s Web site.

PCAOB Auditing Standard 18 on Related Parties

On October 21, 2014, the SEC issued an order approving PCAOB Auditing Standard 18, amendments to certain PCAOB auditing standards regarding significant unusual transactions, and other amendments to PCAOB auditing standards, including required procedures for obtaining an understanding of a company’s financial transactions with its executive officers.

For detailed information about the standard and amendments, see Deloitte’s June 23, 2014, Heads Up.

PCAOB’s Rules on Auditing Supplemental Information

On February 12, 2014, the SEC released an order approving PCAOB Auditing Standard 17 (issued in October 2013), which prescribes the auditor’s responsibilities related to supplemental information accompanying a registrant’s financial

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3 Alternatives already under consideration by the SEC regarding the use of IFRSs in the United States include (1) adopting IFRSs outright, (2) giving U.S. registrants the option of filing IFRS financial statements, and (3) using the so-called “condorsement” approach.
Cybersecurity

Cybersecurity Roundtable

On March 26, 2014, the SEC hosted a roundtable on cybersecurity and the related challenges for market participants (e.g., public companies, broker-dealers, investment advisers, and transfer agents). In her opening remarks, SEC Chairman Mary Jo White highlighted that cybersecurity threats are global and pose a grave risk to our economy, including “our critical infrastructures, our financial markets, banks, intellectual property, and . . . the private data of the American consumer.” She noted that these risks are “first on the Division of Intelligence’s list of global threats, even surpassing terrorism.” Panelists from various backgrounds, such as government officials, professional service providers, academics, investors, preparers, and market exchange representatives, shared their views on key topics, including the current cybersecurity landscape, public-company disclosure issues, and the role of the board of directors and senior leadership in assessing and responding to cybersecurity threats.

See Deloitte’s April 8, 2014, Heads Up for additional information.

Risk Alert

On April 15, 2014, the SEC’s Office of Compliance, Inspections, and Examinations issued a cybersecurity risk alert that provides additional information on its “initiative to assess cybersecurity preparedness in the securities industry.” The risk alert (1) highlights risks and issues that the staff has identified and describes factors for registrants to consider when assessing supervisory, compliance, and other risk management systems related to these risks and (2) allows registrants to make changes, as appropriate, to address or strengthen these systems. While the risk alert was issued to highlight considerations for registrants in the financial services industry, it is also relevant to the P&U sector.

SEC Staff Clarifies Views Regarding Presentation of New Revenue Guidance in Selected Financial Data

At the Financial Accounting Standards Advisory Council (FASAC) meeting on September 11, 2014, the SEC staff clarified its views on how registrants should reflect their implementation of ASC 606 (the “new revenue standard”) in the five-year selected financial data table required under SEC Regulation S-K, Item 301. The staff indicated that it would not object if such implementation is reflected on a basis that is consistent with the adoption in its financial statements (i.e., in less than each of the five years in the table). In other words, a registrant could present revenues in a manner consistent with the new revenue standard in the five-year table for (1) only the most recent three years if the registrant uses the full retrospective method to adopt the new revenue standard or (2) only the most recent fiscal year if it uses the modified transition basis. Regardless of the transition method adopted, registrants would be expected to disclose the method they used to reflect the information (e.g., how the periods are affected) and that the periods are not comparable.

Communications to XBRL Filers

On July 7, 2014, the SEC staff issued the following two documents for registrants that submit interactive data (XBRL) exhibits along with their filings.

- Sample Letter Sent to Public Companies Regarding XBRL Requirement to Include Calculation Relationships — Reminds registrants that the XBRL rules “require that [registrants] include calculation relationships for certain contributing line item elements for [the] financial statements and related footnotes.” Registrants are advised to “take the necessary steps to ensure that [they] are including all required calculation relationships” in their XBRL files.
SEC Staff Comments

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

Over the past year, the SEC staff’s comments to registrants from the P&U industry have continued to focus on:

- Accounting for the impact of ratemaking.
- Regulatory disallowance of plant, property, and equipment (PP&E).
- Identification of possible phase-in plans.
- Parent and subsidiary dividend restrictions.

The staff also continues to question whether registrants in the P&U industry have complied with the (1) requirement in ASC 450 to disclose the range of loss in connection with litigation and other contingencies and (2) segment reporting requirements in ASC 280.

In addition, because many utilities perform both regulated and nonregulated business activities, the SEC staff has asked registrants to discuss their analysis of whether to separately disclose the revenues and costs of revenues related to the nonregulated activities.

The SEC staff has also commented on various aspects of MLPs, a structure commonly used in the P&U industry. Specifically, the staff has commented on the characterization of distributed cash flows and the basis for the calculation of earnings per unit in dropdown transactions.

Accounting for the Impact of Ratemaking

<table>
<thead>
<tr>
<th>Example of an SEC Comment</th>
</tr>
</thead>
<tbody>
<tr>
<td>You disclose that ${X}$ of regulatory assets were not earning a rate of return as of September 30, 2013. You subsequently disclose that a portion of the regulatory asset related to pensions and other postemployment benefits relating to the unfunded differences between the projected benefit obligation and plan assets also does not earn a rate of return, but do not disclose an amount. Please revise to disclose the total amount of regulatory assets for which you do not earn a rate of return. Refer to ASC 980-340-50-1.</td>
</tr>
</tbody>
</table>

The SEC staff continues to ask rate-regulated utilities to disclose (1) how their current regulated rates are designed to recover their specific costs of providing service, (2) the nature of all their material regulatory assets and liabilities, (3) the anticipated recovery period of their regulatory assets or refund period of their regulatory liabilities, (4) whether a particular regulatory asset is earning a rate of return, and (5) their accounting policies related to revenues subject to refund. In addition, the staff may request supplemental explanations or separate detailed analysis and evidence that support the registrant’s recognition of regulatory assets.
Regulatory Disallowance of Property, Plant, and Equipment

Example of an SEC Comment

It is our understanding that you continued to recognize the \$X of capital costs related to your recently completed administrative and operations buildings as of June 30, 2013. If our understanding is correct, please tell us the specific facts and circumstances you considered in continuing to recognize said capital costs after the draft decision was issued, and your consideration of ASC 980-360-35-12. Please also tell us what events you believe would trigger derecognition of said capital assets.

Recently, various public-utility registrants have received comments from the SEC staff about how they applied ASC 980-360-35, which provides guidance on an entity’s subsequent measurement and recognition of PP&E. Registrants have been asked to explain considerations related to disallowances of PP&E in light of recent regulatory orders by state public-utility commissions that limit a public-utility entity’s cost recovery. Also, given the increasing costs of capital projects and cost caps imposed by regulatory authorities at the time they approve large new capital projects, the SEC staff has requested disclosures regarding the estimated costs of capital projects and details about the costs that could change during construction. SAB Topic 10.E states that “disallowed costs for recently completed plants [should] be charged to expense when the disallowance becomes probable and can be reasonably estimated.” ASC 980-360-55-18 contains an example illustrating the accounting for the disallowance of plant cost resulting from a cost cap.

Identification of Possible Phase-In Plans

Example of an SEC Comment

Please supplementally explain the history of the regulatory asset relating to depreciation including why a portion of depreciation for financial reporting purposes was deferred. Tell us over what period it arose and the identity of the plant(s) to which it relates to including whether any plant(s) were recently completed. Tell us when you started amortizing this regulatory asset.

Since many regulators wish to keep rates down in a current rate proceeding, a regulator may decide to defer costs associated with a major new plant addition. A deferral of any costs associated with a major new plant addition could be a phase-in plan. In accordance with ASC 980-340-25-2, cost deferrals are not permitted for phase-in plans. To qualify as a phase-in plan, a method for recognizing allowable costs must meet three criteria outlined in ASC 980-360-20. Ratemaking methods that can result in a phase-in plan include those under which:

- Rates for a new facility are leveled.
- Rates are based on the levelized lease payments under a capital lease (or power purchase agreement that meets the definition of a lease).
- A percentage of an overall rate increase that has been approved is deferred and included in rates in later years.
- The depreciation expense of a major new plant is deferred and included in rates in later years.

If a major newly completed plant is being included in rates for the first time and the regulator provides for a deferral of any costs associated with the new plant for inclusion in future rates rather than as part of cost of service in the current proceeding, those costs may not qualify as a regulatory asset under U.S. GAAP unless an exception applies, regardless of the probability that the incurred costs will be recovered in future rates.
Dividend Restrictions

Example of an SEC Comment

We note the significant number of debt agreements maintained by your wholly-owned subsidiaries along with your disclosure that you are required to comply with certain covenants in connection with the various long term loan agreements. Please tell us whether there are any subsidiary restrictions for paying cash dividends. Additionally, please tell us the amount of restricted net assets as defined in Rule 4-08(e)(3) of Regulation S-X as of the end of most recently completed year and how you compute the amount. In addition, if the restricted net assets exceed 25 percent of your consolidated net assets, please provide the disclosures required by paragraphs 3(i) and (ii) of Rule 4-08(e) of Regulation S-X and Schedule I prescribed by Rule 12-04 of Regulation S-X as required by Rule 5-04 of Regulation S-X.

The financial flexibility of registrants in the P&U industry and the nature of their relationships with affiliated parties, including the parent company, may be constrained by regulation. Subsidiaries often enter into financing agreements that may restrict (1) the transfer of assets in the form of advances, loans, or dividends to the parent company or another affiliated party or (2) other types of transactions with affiliates. The inability of a subsidiary to transfer assets to the parent company could, in turn, restrict the parent company’s ability to pay a dividend to its shareholders. In addition, holders of significant noncontrolling interests in a subsidiary may influence the subsidiary’s operations.

Various public-utility registrants have received comments from the SEC staff about their compliance with Regulation S-X, Rules 4-08(e) and 5-04. The staff has questioned whether such registrants adequately considered the Federal Power Act as well as FERC rules, state rules and regulations, and other regulations that restrict transfers of assets. In addition, the staff has asked public-utility registrants whether, in the absence of regulatory restrictions, they have considered other limitations (e.g., debt agreement covenants), which could restrict the transfer of assets from a subsidiary to the parent company through dividends, loans, advances, or returns of capital.

As a result of the staff’s comments, several P&U registrants have been required, or have agreed, to prospectively (1) expand their notes to the financial statements about potential dividend restrictions in accordance with Rule 4-08(e) and (2) include a Schedule I in their annual Form 10-K in accordance with Rule 5-04. A registrant must determine whether it needs to comply with Rule 4-08(e) independently of Rule 5-04 because compliance with one set of disclosure requirements does not satisfy the requirements of the other.

See Deloitte’s SEC Comment Letters — Including Industry Insights: A Recap of Recent Trends for a more detailed discussion of trends identified in the SEC staff’s comment letters, which includes those that apply to P&U registrants.
Section 3
International Financial Reporting Standards
IFRS Agenda Items

The sections below discuss IFRS-related topics that are particularly applicable to P&U companies.

Reporting the Financial Effects of Rate Regulation

In September 2012, the IASB embarked on a comprehensive rate-regulated activities project to address the lack of IFRS guidance on rate regulation. The project began with a research phase. After three months, the IASB decided to expand the project by adding another phase that eventually resulted in the issuance of a limited-scope standard on regulatory deferral accounts, IFRS 14, on January 30, 2014. Then, on September 17, 2014, the IASB issued a discussion paper (DP) in connection with its more comprehensive project on rate regulation, which is designed to address the broader issue of whether regulatory deferral accounts meet the definition of an asset or liability under the IASB’s conceptual framework.

Issuance of IFRS 14 on Regulatory Deferral Accounts

IFRS 14 permits first-time adopters of IFRSs to continue to account, with some limited changes, for regulatory deferral account balances (both assets and liabilities) in accordance with their previous GAAP, both when initially adopting IFRSs and in subsequent financial statements. Regulatory deferral account balances, and fluctuations in them, are presented separately in the statement of financial position and statement of profit or loss and other comprehensive income. Specific disclosures are also required.

This standard is elective and applicable only upon the initial adoption of IFRSs; therefore, it cannot be applied by entities that have previously adopted IFRSs. Further, to be eligible to apply IFRS 14, an entity must meet the standard’s criteria for rate-regulated activities.

First-time adopters must apply all other IFRSs before applying IFRS 14. Therefore, regulatory deferral accounts represent incremental amounts approved by the regulator that are recognized over and above amounts that are recognized under other IFRSs.

The standard replaces the commonly used U.S. GAAP terms “regulatory assets” and “regulatory liabilities” with “regulatory deferral account debit balances” and “regulatory deferral account credit balances,” respectively (collectively referred to as “regulatory deferral account balances”). The IASB will address whether such balances qualify as assets and liabilities under IFRSs as part of its comprehensive project on rate regulation.

Under IFRS 14, the sum of current and long-term assets or liabilities recognized under other standards is presented as a subtotal in the statement of financial position and then added to the regulatory deferral debit or credit balances and any related DTA or DTL. The resulting sum is presented as total assets or liabilities and regulatory deferral account debit or credit balances. Regulatory deferral account balances are not segregated into current and noncurrent components.

The objective of the disclosure requirements in IFRS 14 is to enable financial statement users to evaluate the nature of, and risks associated with, the specific rate regulation regime and the effects of that rate regulation on the reporting entity’s financial position, financial performance, and cash flows. In particular, IFRS 14 requires entities to explain activities that are subject to rate regulation by disclosing:

- The nature and extent of the rate-regulated activities.
- The identity of the rate regulator and whether the rate regulator is a related party.
- How future recovery of each class of regulatory deferral account debit balance or reversal of each class of regulatory deferral account credit balance is affected by risks and uncertainty.

These disclosures can be presented in the notes to the financial statements or incorporated into the financial statements by cross-reference to another statement, such as MD&A, provided that the regulator permits such alternative treatment.
IFRS 14 should be applied in an entity’s first annual IFRS financial statements for periods beginning on or after January 1, 2016. Earlier application is permitted.

**Discussion Paper on Rate Regulation**

The purpose of the DP is to solicit feedback from constituents on whether, and under what circumstances, the financial effects of rate regulation should be incorporated into financial reporting. The DP does not propose any specific accounting requirements.

The DP focuses on a generic type of rate regulation called “defined rate regulation,” which “applies when customers have little or no choice but to purchase the rate-regulated goods or services from the entity.” In a defined rate regulation scheme, the rate-regulated entity is permitted to recover “a determinable amount of consideration (the ‘revenue requirement’) in exchange for the rate-regulated activities that it performs.” Moreover, a rate-adjustment mechanism is installed to reverse differences between the amounts billed to customers and the amounts accrued under the revenue requirement. These differences are sometimes considered a combination of rights and obligations.

The rights and obligations in rate regulation can be implicit or explicit. Specific accounting requirements may be needed for the implicit rights and obligations related to rate regulation, but not for the explicit rights and obligations. The DP introduces various accounting alternatives for implicit rights:

- Recognition of regulatory deferral accounts as assets and liabilities.
- Recognition of rights and obligations as one intangible asset.
- Application of regulatory accounting requirements (even when such requirements conflict with otherwise applicable IFRSs).
- Development of specific IFRS requirements.
- Prohibiting the recognition of regulatory deferral account balances.

The DP further distinguishes between cost-based and incentive-based rate-regulatory schemes. Pure cost-based schemes allow an entity to recover cost plus a reasonable rate of return (no more, no less), while incentive-based schemes typically have a profit target. The DP indicates that “defined rate regulation” is a hybrid form of regulation based on cost-recovery principles but which also includes incentive mechanisms that may permit an entity to under-perform or over-perform when compared to the target profit or rate of return.

Comments on the DP are due by January 15, 2015. For more information about the DP, see Deloitte’s December 2014 Power & Utilities Spotlight.

**Canadian Companies’ Election of U.S. GAAP in Lieu of IFRSs**

In Canada, most “publicly accountable enterprises” were required to adopt IFRSs for financial years beginning on or after January 1, 2011. However, through a series of one-year deferrals, mandatory adoption of IFRSs has been deferred until 2015 for qualifying entities with rate-regulated activities.

Like U.S. GAAP, Canadian GAAP requires that the impact of rate-regulated activities be recognized directly in the financial statements of rate-regulated entities either as regulatory assets or regulatory liabilities. IFRSs did not allow for such treatment before the issuance of IFRS 14. As a result, the required adoption of IFRSs (pre-IFRS 14) by utilities and other participants in rate-regulated industries presented certain difficulties, including significant income statement volatility (e.g., the inability to record regulatory assets and liabilities) and the need to maintain two sets of books to inform regulators about the impact of regulation on the company’s results.
Consequently, Canadian utilities have pursued multiple paths over the past few years, including:

- Taking advantage of the AcSB’s continued one-year IFRS deferrals for qualifying utilities (see above), which expire in 2015.
- Adopting U.S. GAAP for local filings when permitted.
- Listing securities and filing in the United States under U.S. GAAP.
- Proceeding with IFRS adoption, generally without recognizing regulatory assets and liabilities.

As a result of the uncertainty regarding the timing and outcome of the IASB’s project, more and more Canadian rate-regulated companies have been electing to adopt U.S. GAAP. The primary reasons Canadian companies have given for adopting U.S. GAAP in lieu of IFRSs are transparency and simplicity. The belief is that adoption of IFRSs will create a disconnect between the underlying regulatory model and the entity’s financial reporting, which would create confusion among stakeholders. In addition, because U.S. GAAP and the legacy Canadian GAAP are similar, transitioning to U.S. GAAP has a minimal impact on the accounting determinations related to rate base, cost of service, and revenue requirements.

The remaining qualifying entities with rate-regulated activities in Canada that have not yet adopted IFRSs or U.S. GAAP will be required to transition to IFRSs beginning with fiscal years starting on January 1, 2015, or later. Generally, it is expected that these first-time adopters of IFRSs will early adopt IFRS 14, which, in most cases, allows for grandfathering of legacy rate-regulated accounting applied under Canadian GAAP. However, IFRS 14 does change presentation and disclosure requirements related to regulatory assets and liabilities.
Section 4
Industry Accounting Hot Topics
Depreciation Adjustments

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

“Mirror Depreciation”

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

Nonlegal Cost of Removal

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

Negative “True” Depreciation

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

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

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

ASC 980-340 defines a phase-in plan as follows:

Any method of recognition of allowable costs in rates that meets all of the following criteria:

a. The method was adopted by the regulator in connection with a major, newly completed plant of the regulated entity or of one of its suppliers or a major plant scheduled for completion in the near future.

b. The method defers the rates intended to recover allowable costs beyond the period in which those allowable costs would be charged to expense under [U.S. GAAP] applicable to entities in general.

c. The method defers the rates intended to recover allowable costs beyond the period in which those rates would have been ordered under the rate-making methods routinely used prior to 1982 by that regulator for similar allowable costs of that regulated entity.

ASC 980-340 prohibits capitalization of the allowable costs that the regulator defers for future recovery under a phase-in plan. A rate decision that defers the recognition of depreciation or other allowable costs associated with a newly completed major capital project (including a capital lease) may meet the definition of a phase-in plan. Under ASC 980-340, an entity is not permitted to record a regulatory asset for a phase-in plan, regardless of whether it is probable that the deferred costs will be recovered in the future.

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

Normal Purchases and Normal Sales (NPNS) Scope Exception

In accordance with ASC 815-10-15-35, for a “contract that meets the net settlement provisions of paragraphs 815-10-15-100 through 15-109 and the market mechanism provisions of paragraphs 815-10-15-110 through 15-118 to qualify for the [NPNS] scope exception, it must be probable at inception and throughout the term of the individual contract that the contract will not settle net and will result in physical delivery.” In assessing whether continued application of the NPNS scope exception is appropriate, an entity must consider whether the facts and circumstances suggest that the counterparty to the contract may net-settle the contract, negotiate an early settlement for the contract, or otherwise reach an outcome indicating that it no longer is probable that the contract will result in physical delivery.

A contract that no longer qualifies for the NPNS exception but that still meets the definition of a derivative would need to be recorded at fair value in the entity’s financial statements, with an offsetting entry to current-period earnings. As with other derivatives, subsequent changes in the fair value of the contract would be recognized in earnings. For rate-regulated entities with regulatory recovery mechanisms, the change in fair value of the contract would be recognized as a regulatory asset or liability rather than in current-period earnings.

Impact of Contract Modifications and Force Majeure

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

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

Impact of Reduced Purchase Quantities and Volumetric Optionality

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

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

In addition to evaluating modifications of existing coal contracts, entities may negotiate cash settlements, enter into offsetting positions, or enter into new contracts that provide for volumetric optionality. Entities should carefully evaluate modifications, early cash settlements, and offsetting contracts to assess the impact on their ability to assert that the contract in question, and other similar contracts, will not settle net and will result in physical delivery. Entities should also consider whether the ability to enter into offsetting positions indicates that the coal is “readily convertible to cash” (RCC), as that phrase is used in the determination of whether a contract meets the definition of a derivative. When contracts contain volumetric optionality, entities should carefully consider whether the contract meets the definition of a derivative (i.e., whether the coal is RCC). An example of a coal contract with volumetric optionality is a contract for the delivery of 2 million tons per year in which the purchaser has the option to reduce annual delivery to 1.8 million tons or to increase delivery to 2.2 million tons. If volumetric optionality exists, the contract will not qualify for the NPNS election.1

Application of the NPNS Scope Exception to Certain Electricity Forward Contracts in Nodal Energy Markets

Background

To maintain the integrity of an electricity system, a supply-and-demand balance must exist on a system-wide basis, including the many points in the system at which electricity may be delivered or withdrawn. In its November 5, 2014, meeting handout, the FASB points out that “[h]istorically, power companies in the U.S. have built, owned, and operated” their own electricity grid systems. Each power company operated its transmission system in such a way that the consumption of electricity “was balanced with the supply of electricity generated, either by their own plants or by purchases from others.”

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1 A power purchase or sales agreement that is a capacity contract may qualify for the NPNS election under ASC 815-10-15-45 through 15-51.
The Board handout goes on to state that “[c]hanges in U.S. energy policy encouraged (a) the unbundling of interstate electricity transmission facilities (high voltage power lines) from other parts of the power generation and delivery supply chain; (b) operation of those transmission facilities on a functionally independent basis to promote open access to the grid; and (c) greater use and formalization of interconnection groups on a regional basis.” Many power companies joined a regional transmission organization (RTO) and, along with other RTO members, authorized day-to-day grid operations to be managed by an independent system operator (ISO). The handout emphasizes that “ISOs do not own the transmission system or generation facilities but instead manage and operate the grid.” An ISO-run nodal energy market essentially functions as a common carrier, and federal regulations require such a market to provide all qualified market participants with nondiscriminatory access to the electricity grid.

Developments in the wholesale power markets have resulted in changes in how usage of the grid is priced. ISOs typically employ nodal price signals to incentivize grid users to transmit electricity via the most economical path and (in the long term) encourage investment in generation and transmission assets. These objectives are accomplished by using locational marginal pricing (LMP) to establish “a price for the delivery and withdrawal of electricity at each specific location (referred to as a node or delivery point) on the grid where electricity can be produced or used.” LMPs are established relative to the congestion at nodes (e.g., highly congested nodes with more requests for usage than available capacity will have a higher LMP). The ISO determines a separate LMP for each node, and the price for the transmission of power within the grid equals the difference in LMP at the respective nodes multiplied by the quantity of power delivered between them.

Forward contracts for the physical delivery of electricity often meet the definition of a derivative in ASC 815. However, questions have arisen regarding whether the NPNS scope exception can be applied to such contracts in a nodal market operated by an ISO when the delivery point of the forward contract (the source) differs from the location of the purchaser’s customers (the sink) and LMP charges and credits are therefore incurred in connection with the delivery of power to end users. Such questions have arisen because of the interaction of (1) nodal LMPs, (2) gross calculation of charges and credits on the ISO bill, (3) the inability of market participants to procure physical transmission on a forward basis, (4) the physical delivery of electricity purchased to liquid pricing locations rather than the sink, and (5) the mechanics of title transfer in certain ISO markets.

Views currently differ on whether the NPNS scope exception applies to the type of contract described above. For example, some believe that such contracts are eligible for the NPNS scope exception because they, in substance, result in physical delivery. Consumption of the electricity at the sink is evidence to support this position, since all sources and uses of power within the electricity grid must be balanced and equal. However, others believe that the contracts do not qualify for the NPNS exception because the transaction with the ISO constitutes net settlement of the physical forward and the contracts therefore are not physically delivered.

Inquiry

A working group consisting of members of each of the Big Four accounting firms and the EEI submitted an inquiry to the SEC in the fall of 2013 regarding NPNS eligibility for forward electricity transactions in nodal markets. The focus of the inquiry was whether the NPNS scope exception can be applied to a forward power contract for physical delivery within a nodal market operated by an ISO when the delivery point of the forward contract differs from the location of the purchaser’s customers. A similar issue exists for generators (sellers) with forward contracts that deliver at locations other than their plant busbar. The SEC staff considered this issue and engaged in significant dialogue with the working group through much of 2014. Ultimately, the SEC did not answer the question but instead referred the issue to the FASB for its consideration. On November 5, 2014, the FASB voted in favor of adding the issue to the EITF’s agenda. We understand that the Board will conduct an education session on the matter in January 2015 and that the EITF will commence deliberations at its March 2015 meeting. Entities affected by this issue should consult with their auditors regarding the impact of this open inquiry on existing and new NPNS designations.
Section 4 — Industry Accounting Hot Topics: Impact of Subsequent Events Related to Regulatory Matters

Impact of Subsequent Events Related to Regulatory Matters

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

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

Loss Contingencies Versus Gain Contingencies

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

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

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

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

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

Considerations for Regulated Utilities

ASC 980 does not specifically address subsequent events unique to the P&U industry. Accordingly, entities should use the general guidance in ASC 855 to evaluate the accounting for subsequent events related to regulatory matters. Legislation does not constitute a regulatory matter. The enactment of a law or the issuance by a government agency of a new regulation after the balance sheet date but before issuance of the financial statements would be accounted for as a
nonrecognized subsequent event (because the newly enacted law or regulation does not provide evidence of conditions that existed as of the balance sheet date).

Although a regulated utility’s application of the guidance in ASC 855 will depend on its particular facts and circumstances, the examples below illustrate how a regulated utility company might apply the guidance to typical subsequent events.

Subsequent-Event Examples

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

On July 15, 2014, Utility A’s regulator issued an order with respect to a routine review of Utility A’s fuel clause adjustment calculation for the period from January 1, 2013, to December 31, 2013. Utility A had not yet issued its June 30 financial statements. In this order, the regulator ruled that Utility A should have credited certain wholesale sale margins to its retail fuel clause. The order required Utility A to refund $5 million. Utility A was aware that intervenors were questioning this item on the basis of testimony that had been filed a few months earlier but had expected to prevail in this matter, which represented a loss contingency as of June 30. The July 15 order was a Type 1 subsequent event that provided additional information about the probability and amount of the loss as of June 30. Therefore, Utility A accounted for the effect of this order in its financial statements as of and for the period ended June 30, 2014, and included the disclosures prescribed by ASC 980-605.

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

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

**Appeal of Prior Unfavorable Rate Order**

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

In conjunction with its ruling on a rate case, Utility D’s regulator concluded that there was significant management error in the planning and construction of a recently completed power plant. In the order issued after the balance sheet date but before the financial statements had been issued, the regulator required that plant costs in excess of a specified amount not be recovered in rates. The recovery of this plant was a key issue throughout the proceedings and the primary basis for the request for an increase in rates. Before the issuance of the rate order, Utility D had concluded that the likelihood of a disallowance was reasonably possible but less than probable. Utility D concluded that the post-balance-sheet ruling constituted additional significant objective evidence about the likelihood of disallowance as of the balance sheet date. Accordingly, Utility D updated its assessment of the probability of a disallowance as a result of this Type 1 subsequent event and recorded a charge to earnings in the current period. Post-balance-sheet events other than a final order from a regulator may also constitute significant objective evidence about conditions that exist as of the balance sheet date.

Subsequent Natural Disaster Affects Likelihood of Recovery of a Regulatory Asset

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

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

Surprise Development in a Proceeding

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

In connection with its current rate proceeding, shortly after year-end, Utility F commenced settlement discussions. Intervenors indicated that they were willing to settle the case if Utility F would forgo the remaining amortization of the storm damage costs. While Utility F strongly disagreed with the intervenors’ position on storm damage costs, in the context of the overall settlement proposal, Utility F was likely to agree to the settlement. On the basis of the settlement terms, no other existing regulatory assets were at risk (i.e., Utility F did not concede the storm cost asset to protect another regulatory asset whose loss was otherwise probable as of the balance sheet date), and the return on equity was slightly higher than Utility F was expecting. Shortly before the financial statements were issued, the parties agreed to the settlement. On the basis of precedent, Utility F believed it was probable that its regulator would approve the settlement. Utility F concluded that this settlement represented a Type 2 subsequent event and disclosed the settlement in the notes to the financial statements.

In accordance with ASC 980-360, when it becomes probable that part of the cost of a recently completed plant will be disallowed for rate-making purposes and the amount of the disallowance can be reasonably estimated, the estimated amount of the probable disallowance is deducted from the reported cost of the plant and recognized as a loss. The terms “probable,” “reasonably possible,” and “remote” are defined in ASC 450-20, and entities must exercise considerable judgment when applying them.
facts and conditions that existed as of the balance sheet date. Utility F believed that in the absence of its decision to agree to the settlement, its regulator most likely would have continued to allow recovery of the deferred costs over the remaining two years.

Companies need to exercise judgment when there are surprise developments. For example, had there been any discussions with intervenors before the balance sheet date about the potential to forgo recovery of the deferred costs, or had testimony been filed advocating no further recovery, questions would have been raised as of the balance sheet date about the probability of recovery and the settlement may have indicated a Type 1 subsequent event. In most cases in which a rate order issued after year-end contains an unexpected ruling affecting a regulatory asset as of the balance sheet date, such a rate order is typically considered a Type 1 subsequent event if commission staff or intervenors have questioned the matter as part of the rate proceedings or it was clear that the item disallowed was subject to a prudence review in the current regulatory process.

Plant Abandonments and Disallowances of the Costs of Recently Completed Plants

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

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

Plant Abandonment

ASC 980-360 states that when it becomes probable that an operating asset or an asset under construction will be abandoned, the associated cost should be “removed from construction work-in-process or plant-in-service.” ASC 980-360 further indicates that if the regulator is likely to provide a full return on the recoverable costs, a separate asset should be established with a value equal to the original carrying value of the abandoned asset less any disallowed costs. If the regulator is likely to provide a partial return or no return, the new asset value should equal the present value of the future revenues expected to be provided to recover the allowable costs of the abandoned asset and any return on investment. The utility’s incremental borrowing rate should be used to measure the present value of the new asset. Any disallowance of all or a part of the cost of the abandoned asset should be recognized as a loss when it is both probable and estimable. During the recovery period, the new asset should be amortized to produce zero net income on the basis of the theoretical debt and interest assumed to finance the abandoned asset. ASC 980-360 does not specify where the separate asset should be classified on the balance sheet; it only indicates that the cost amount should be removed from CWIP or plant in service. In practice, most companies have classified the separate asset as a regulatory asset or as a category of plant other than CWIP or plant in service.

Matters Related to Abandonment Accounting

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

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

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

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

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

**Reconsideration of Abandonment Decision**

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

**Disallowances of Costs of Recently Completed Plants**

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

Utilities often do not record a disallowance before receipt of a rate order because the loss is not reasonably estimable. However, there could be circumstances in which a rate order has not been issued but a disallowance loss could be probable and reasonably estimable. If the prudence of a recently completed plant is being challenged in a current rate proceeding, a utility must use significant judgment in evaluating the likelihood and estimate
of a loss. If the utility does not record the loss in its financial statements, it should disclose the range of a reasonably possible loss in the footnotes if the loss could be material.

There is no specific guidance in (1) ASC 980-360 or ASC 360-10-35 defining a “recently completed plant” or (2) ASC 980-340 defining a “newly completed plant.” In practice, these terms have effectively been defined on the basis of facts and circumstances, so some diversity has resulted. The starting point for determining what constitutes a recently completed plant or a major, newly completed plant is typically the time from the completion-in-service date until the plant owner files its initial rate request for inclusion of the plant in allowable costs. Unlike the phase-in plan guidance in ASC 980-340, which refers to “major” in connection with “newly completed plant,” the disallowance guidance in ASC 980-360 refers to “recently completed plant” and does not introduce the concept of “major.” As a result, in the evaluation of potential disallowances, the guidance in ASC 980-360 applies to all recently completed additions to PP&E, not just “major” new additions.

Questions that have arisen about the definition of a new or recently completed plant include:

- Is a newly acquired “used” plant (e.g., the purchase of a 10-year-old power plant) considered a new or recently completed plant?
- If a component of an asset is replaced (e.g., a replacement turbine at a power plant), is that replacement component considered a new or recently completed plant?

Because ASC 980-360 does not address these issues, diversity in practice has resulted.

ASC 980-360 also addresses explicit, but indirect, disallowances that occur when no return or a reduced return is permitted for all or a portion of the new plant. In the case of an indirect disallowance, if the regulator does not specify the amount of the disallowance, the amount must be calculated on the basis of estimated future cash flows. To determine the loss resulting from an indirect disallowance, entities should estimate and discount the future revenue stream/cash flows allowed by the regulator by using a rate consistent with that used to estimate the future cash flows. This amount should be compared with the recorded plant amount, and the difference should be recorded as a loss. Under this discounting approach, the remaining asset should be depreciated in a manner consistent with the rate-making and in a manner that would produce a constant return on the undepreciated asset that is equal to the discount rate. Although an explicit but indirect disallowance must be recorded as a loss, ASC 980-360-35-15 notes that “an entity is not required to determine whether the terms of a settlement agreement or rate order contain a hidden, indirect disallowance.” For example, if a regulator provides a return on equity on a recently completed plant that is lower than other rate-base items but still a reasonable return, we would generally not view the provision of a lower return by the regulator as an indirect disallowance.

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

Disallowances of costs for plants that are not recently completed are recognized in accordance with general U.S. GAAP. For example, assume that (1) a company puts a new plant into service and then goes through a rate case when the prudence of the costs are scrutinized and (2) the regulator concludes that the entire amount capitalized should be included in rate base, with depreciation expense on the entire capitalized amount included in cost of service. Further assume that the plant costs are questioned a few years later in the next rate case and that the regulator disallows a specific amount of the plant cost. A disallowance charge based on ASC 980-360 should not be recorded because that plant is no longer a recently completed plant. An entity should apply the impairment criteria in ASC 360 when evaluating disallowances of plant costs for PP&E that is not recently completed. However, because of the typically large grouping of assets based on the lowest level of cash flows for rate-regulated PP&E, it would be rare that an ASC 360 impairment charge would result from a disallowance of a “not recently completed” plant.

Accounting for Renewable Energy Certificates

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

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

**Lease Accounting**

As noted above, electricity suppliers often purchase RECs from third-party owners of renewable energy generation facilities. Frequently, the underlying renewable energy is also sold to the electricity supplier, and it is fairly common for a purchaser to acquire 100 percent of the electricity and RECs associated with the facility. Entities should evaluate such contracts under ASC 840 to determine whether they contain a lease.3

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

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

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

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

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

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

Another acceptable view is that RECs may be considered outputs because they (1) result directly from a facility’s production process and (2) represent discrete marketable elements.4 Proponents of this view believe that it is not necessary for outputs to be “tangible” as long as they are generated as a result of the operations of the PP&E and represent discrete elements that could be sold to other entities or other market participants. Such proponents also note that because RECs can significantly affect the underlying value of the PP&E, they are an important consideration in the evaluation of whether the right to use

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3 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.

4 Economic attributes are generally not considered outputs in the determination of whether an arrangement contains a lease unless they are both (1) generated by the facility’s production process and (2) separately marketable. For example, although PTCs are linked to a renewable facility’s production levels, they are not considered outputs because they can only be conveyed through an ownership interest and therefore are not separately marketable.
the renewable energy generation facility has been conveyed to the purchaser. They should therefore also be considered in
the determination of whether parties other than the purchaser are taking more than a minor amount of the output or other
utility that will be produced or generated by the PP&E.

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

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

See Section 6 for a discussion of the leases project and the proposed changes to lease accounting. On the basis of the
current ED, the rules related to determining whether an arrangement contains a lease are expected to change.

### Derivative Considerations

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

Renewable portfolio standards in several states have resulted in secondary markets for REC exchanges (e.g., the Green
Exchange). Because such markets are still evolving, the assessment of the “net settlement” criterion (more specifically,
whether the RECs are 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 entities continually evaluate contracts to buy or sell RECs over their lives, contracts that did not previously qualify
as derivatives may later meet the definition. Therefore, as REC markets develop, entities should consider use of the
“conditional” NPNS designation to reduce the risk of potential effects on the financial statements.5

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

### Asset Type and Accounting Value

Although both U.S. and international accounting standard setters have previously attempted to address the issues of
determining asset type and accounting value, the FASB and IASB have not provided any authoritative accounting literature
on this topic or on emission allowances. In the meantime, many companies have developed accounting policies in the
absence of explicit authoritative guidance.

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

5 Provided that a contract meets the criteria for the NPNS exception, an entity can designate the contract under the NPNS exception before that contract qualifies as a
derivative. Such designation is commonly referred to as the “conditional” NPNS designation.
### Asset Type

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

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

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

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

### Accounting Value

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

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

Entities may use multiple accounting models to determine the carrying value of RECs from internal renewable generation sources. Three such models are described below.\(^6\)

#### Incremental Cost

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

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\(^6\) The accounting value models described in this section are applicable to RECs accounted for as “inventory.” ASC 350-30-25-3 notes that the “[c]osts of internally developing, maintaining, or restoring intangible assets [should] be recognized as an expense when incurred.” Therefore, capitalization of internally generated RECs accounted for as intangible assets is not typically supportable under current accounting guidance.
Joint Product Allocation

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

By-Product Allocation

In some circumstances, RECs may be considered a by-product of electricity generation. In other cases (e.g., if renewable portfolio standards may exist in a state without an abundance of renewable generation), RECs may be the primary product developed by the renewable facility, with electricity considered a by-product. Under the by-product method, the by-product would be assigned cost at its fair value, with the residual amount recorded as the cost basis for the principal product. Depending on the principal product and by-product designations, this method could result in faster or slower cost recognition than the previous two methods.

Accounting Value Summary

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

REC Shortfall Considerations

In certain states with renewable portfolio standards, electricity suppliers may be required to purchase RECs when there is a REC shortfall below the required level for the compliance period (e.g., the entity did not generate enough electricity at qualifying facilities to meet its own compliance requirements). Shortfalls of RECs represent obligations that should be recorded as liabilities; however, the timing of liability recognition differs in practice. Some support recognition of a liability only when the entity’s RECs have been exhausted, while others believe that consideration related to expected shortfalls should be recognized throughout the compliance period in accordance with ASC 270. Because of the evolving nature of renewable portfolio standards and the diversity in accounting views, companies should consider discussing the accounting for expected shortfalls with their auditors.

Rate-Case Settlements

A utility company periodically files a rate case with its regulatory commission. This may be due to the commission’s requirements that the utility company file a new rate case or because the utility company has chosen to request new rates. When fully litigated in front of the regulatory commission, the rate-case process is often long, sometimes lasting more than a year from the date the utility company initially files its rate-case request to the date the regulatory commission approves the request. The rate-case process involves data requests from the commission staff and intervenors to the rate case as well as multiple rounds of testimony and hearings.
However, in many regulatory jurisdictions, the utility company and the intervenors will hold settlement discussions. The goal of the settlement discussions is for the utility company and the intervenors to agree to the significant terms of the rate case. The settlement is filed with the regulatory commission in the form of a settlement agreement that the regulatory commission can then review and approve or reject. The advantage of a settlement agreement is that it reduces the period before new rates can be established because hearings and testimony are not required. A settlement agreement may settle all aspects of a rate case or it may refer a portion of the rate case (e.g., recovery of a specific cost) back to the regulator.

Significant terms in a settlement agreement may include the revenue requirement, recovery of various regulatory assets, or the return on rate base.

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

- A utility company should consider preparing a calculation of the hypothetical settled revenue requirement on the basis of the initially filed rate case, filed testimony and responses to intervenor requests, discussions with intervenors and the regulator, and the settlement agreement. This detailed calculation, which is based on the agreed-to revenue requirement, may help the utility company understand the components (e.g., those related to rate base, cost of service, and return on rate base) of the settled revenue requirement and the accounting implications of the settlement. To perform this calculation, the utility company may need input from various departments at the company, including regulatory, accounting, and legal, and will need to use significant judgment depending on the level of detail in the settlement agreement. The calculation of the hypothetical settled revenue requirement should be sufficiently detailed for parties to understand the significant judgments and the allocations made.

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

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

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

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

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

Asset Grouping and Identifiable Cash Flows for Impairment Recognition and Measurement

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

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

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

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

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

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

- **The entity’s distribution characteristics, such as regional distribution centers, local distributors, or individual plants** — The entity may consider how it manages outages and maintenance for its various assets. If management adjusts output at one plant to compensate for an outage at another, interdependent cash flows may exist. By contrast, if each plant is managed individually and there is little coordination throughout the group, an asset grouping method may not be appropriate.
• The extent to which purchases are made by an individual location or on a combined basis — The assessment of this criterion may show that certain costs are incurred for the benefit of individual plants while certain purchases may be for the use of more than one plant. For example, fuel for plants may be purchased from a common fuel source and may be allocated by a central function. This may depend, among other things, on the similarity of the plants as well as their proximity to each other.

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

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

Master Limited Partnerships

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

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

Industry Considerations

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

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

**Predecessor Entity**

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

**Carve-Out Financial Statements**

A parent company often forms an MLP by contributing certain qualifying assets, in which case the predecessor historical financial statements included in the registration statement will be a carve-out of the parent company’s business.

See the Carve-Out Financial Statements subsection for discussion of other relevant accounting and reporting considerations.

**Materiality**

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

**Additional Financial Statements**

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

**Pro Forma Financial Statements**

When the historical financial statements do not reflect the ongoing entity, pro forma financial statements are required. Many MLPs require pro forma financial statements because of newly revised cost-sharing arrangements as well as long-term commercial agreements entered into with the parent. In addition, the consummation of the IPO and the use of the proceeds will need to be reflected.

**Dropdown Transactions**

P&U parent companies that create an MLP structure often will hold back certain qualifying assets to sell, or “drop down” into the MLP, at a later date. A dropdown transaction is considered a transaction between entities under common control. The accounting for transactions between entities under common control is similar to the accounting under the pooling-of-interest method. A transfer of assets and liabilities between the parent entity and the MLP should be recognized at the parent’s carrying amount of these assets and liabilities as of the date of the transfer. Any difference between the carrying amount of the net assets received and the purchase value is considered an equity contribution/distribution. In addition, once the dropdown transaction is reported in the MLP’s financial statements, the income statement and other financial statements of the commonly controlled receiving entity would be recast and combined retrospectively — as if the
transaction had occurred at the beginning of the earliest period presented. The prior years' comparative information should be presented retrospectively only for the periods in which the entities were under common control.

**Carve-Out Financial Statements**

In response to various market factors, utilities may seek to dispose of a portion of their operations or spin off portions of their business into a separate entity. One factor contributing to a recent increase in such divestitures is deregulation in certain jurisdictions, which has resulted in utilities with increasingly unregulated operations. In addition, recent energy efficiency programs and stagnant demand have led utilities to seek value in innovative ways. These and other market considerations have led companies to divest undervalued or strategically misaligned operations to unlock their value.

A carve-out occurs when a parent company segregates a portion of its operations and prepares a distinct set of financial information in anticipation of a sale, spin-off, or divestiture of a portion of its operations, which is referred to as the "carve-out entity." The carve-out entity may consist of all or part of an individual subsidiary, multiple subsidiaries, or even an individual segment or multiple segments. In some cases, one or more portions of a previously consolidated parent company’s subsidiaries may constitute the newly defined carve-out entity.

As used in the discussion below, the term "carve-out financial statements" describes separate financial statements that are derived from the financial statements of a parent company. The form and content of those financial statements will vary depending on the circumstances of the transaction. For example, if the carve-out financial statements are to be used solely by a small, strategic buyer, an unaudited balance sheet and income statement for the most recent fiscal year may be sufficient. A public buyer, however, may need a full set of SEC-compliant audited financial statements, including footnotes, for the three most recent fiscal years. Yet another buyer might ask that the periods be audited but may be completely unconcerned with SEC reporting considerations. Accordingly, assessing the needs of potential financial statement users is critical to understanding the level of detail and number of periods to be presented in the carve-out financial statements. Such an assessment can be particularly complex when the carve-out financial statements are being prepared before all relevant information is known (e.g., before a method of disposal has been determined, before the buyer has been identified).

**Internal Control Considerations**

ICFR is one important item for utilities to consider when carving out a portion of their operations into a new entity. Key questions for entities to ask about ICFR include:

- Has existing ICFR for the host entity been sufficiently precise for purposes of the carve-out financial statements?
- What new accounting and reporting risks exist with respect to the carve-out entity and the process for preparing the carve-out financial statements?

Because carve-out financial statements represent a subset (or subsets) of an existing entity, the parent entity’s ICFR typically governs the carve-out entity’s transactions and processes. However, previous ICFR may not have been sufficiently precise to address the risks of misstatement related to the carve-out financial statements.

Implementing and evaluating ICFR related to carve-out financial statements is critical given the amount of judgment an entity must exercise in preparing these statements. Entities considering the preparation of carve-out financial statements should evaluate ICFR as part of their pre-transaction planning activities and determine whether they need to implement additional control activities, training programs, or financial reporting processes to sufficiently address the risk of material misstatement. Given the nature of carve-out statements, many of the control activities an entity implements will be management review controls.

The sections below discuss some of the considerations an entity should take into account when preparing carve-out financial statements.
Judgments and Allocations

Numerous challenges arise when an entity carves out activity and balances from the parent’s historical financial statements. For the statement of operations, an entity can often specifically identify revenues, including intercompany revenues, related to the carve-out entity. However, expenses can be more difficult. Carve-out financial statements are intended to reflect all costs of doing business. Although costs incurred by the parent on behalf of the carve-out entity must be reflected in the carve-out financial statements, such costs are often related to many different operations and cannot be specifically identified as part of the carve-out entity. In such cases, an entity must use a reasonable allocation method. Allocation methods in the industry are often based on items such as generation capacity, energy generated, headcount, and payroll.

For the balance sheet, an entity generally begins by identifying the assets and liabilities related to the carve-out entity. However, this process can be challenging when some assets or liabilities are commingled or combined with assets or liabilities related to other parts of the business. For example, cash, accounts receivable, and accounts payable are often commingled because they are managed centrally. Goodwill, debt, and pensions can also present a challenge because these assets or liabilities are often not recorded at the level of the carve-out entity. For each of these asset and liability classes, an entity will need to determine whether amounts should be attributed to the carve-out entity.

In addition to implementing control and planning activities to address the risk of material misstatement (as discussed in Internal Control Considerations above), entities should document management’s rationale for significant conclusions reached, since judgments and allocations often have a material impact on the carve-out financial statements.

Tax Considerations

When performing a carve-out, an entity should pay particular attention to the structuring of the legal transaction to avoid unintended tax consequences. Specifically, how the carve-out transaction occurs can affect whether the transaction represents a taxable event. To avoid these unintended consequences, tax departments should be involved in drafting the legal documents governing the transaction. In addition, an entity may need to determine the impact of changes in state tax rates and the changes to apportionment factors if assets are transferred between state jurisdictions.

Reporting Considerations

The sections below discuss aspects of carve-out financial statements that are typically complex and for which reporting considerations often arise. In evaluating these considerations, a reporting entity must use judgment and assess its specific facts and circumstances.

Discontinued Operations

In a carve-out transaction, a parent company generally disposes of a portion of its operations. As a result, the ongoing entity should consider whether the operations that are, or will be, disposed of meet the criteria for classification as held for sale or presentation as a discontinued operation in the parent company’s financial statements. If the criteria for reporting discontinued operations are met, it is unlikely that amounts presented as discontinued operations for the carve-out entity in the parent company’s financial statements would equal the amounts for the operations reflected in the carve-out entity’s separate financial statements (e.g., because of differences in how expenses may have been allocated).

In April, 2014, the FASB issued ASU 2014-08 (codified in ASC 205-20), which changes the criteria for reporting discontinued operations and is expected to reduce the frequency of disposals that qualify for presentation as a discontinued operation. See the Accounting Standards Codification Update section for more information.

Business Segment Disclosure

Disposal transactions may have an impact on the parent entity’s segment reporting. A disposal of a significant portion of the parent entity’s operations could cause a change in management’s view of the business or in the parent entity’s segments. Further, in preparation for a disposal, management may seek to realign the business and may legally transfer operations...
from one segment to another. If segments are restructured, management should consider the guidance in ASC 280-10-50-34, under which an entity is required to retrospectively apply the segment change to earlier accounting periods.

**Transactions Between Entities Under Common Control**

Like the situation described in Business Segment Disclosure above, a transaction within a consolidated group may result in retrospective reporting requirements in accordance with ASC 805-50 if the acquiring entity prepares stand-alone financial statements. For example, in preparation for a disposal, management may transfer certain assets or operations to a new legal entity within the consolidated group. Such transactions are accounted for as transactions between entities under common control and have no accounting impact (other than a possible impact on segment disclosures) at the consolidated level. However, if subsidiaries of the parent entity prepare stand-alone financial statements, there may be an impact when assets or operations are transferred to or from the subsidiary. Because a transaction between entities under common control is accounted for at the parent entity’s historical cost, there is no measurement impact.

The transferring subsidiary generally would report the transfer as a disposal in its stand-alone financial statements and assess whether the disposal should be presented as a discontinued operation. The reporting by the receiving subsidiary depends on whether the transfer represents a “change in reporting entity” under ASC 250. A change in reporting entity results in presentation of the transfer as if it had occurred at the beginning of the earliest reporting period presented in the subsidiary’s stand-alone financial statements (such presentation is often called an “as-if pooling”). Alternatively, the receiving entity prospectively reports transfers that do not represent a change in reporting entity. An entity must use judgment in determining whether a transfer results in a change in reporting entity. Typically, transfers of legal entities or operating businesses would be reported as changes in reporting entity, while transfers of an individual nonfinancial asset would not.

**SEC Reporting**

SEC registrants often have additional things to consider when reporting disposal transactions, including how to report pro forma financial information. For example, Section 2.01 of the SEC’s Form 8-K instructions includes disclosure requirements for acquisitions or dispositions of a significant amount of assets. (Note that Section 2.01 also defines the term “significant.”) The disclosures that an entity is required to provide in accordance with this SEC guidance will depend on the facts and circumstances of the transaction but may include audited financial statements or pro forma financial information that contains the balances and activity of the acquired or disposed-of entity. In these situations, the required financial information is typically based on carve-out financial statements of the transferred entity; certain adjustments may be made on the basis of the nature of the reporting requirements.

**Other Resources**

For additional guidance on carve-out financial statements, see Deloitte’s *A Roadmap to Accounting and Financial Reporting for Carve-Out Transactions* for more information on carve-out financial statements.
Section 5
Energy Contracts, Derivative Instruments, and Hedging Activities
This section summarizes current trends and activity in the P&U sector and how potential rulemaking changes may affect the accounting and reporting for energy contracts.

**Regulatory Activity**

**Impact of Regulatory Trends**

Objectives of the ongoing environmental regulations include reducing emissions, increasing efficiency, and lowering consumer costs. Such rulemaking could lead to the further establishment and growth of regional and national cap-and-trade mechanisms that will assist in the development of primary and secondary markets for trading emissions-related instruments. This development of trading markets could also pave the way to trading financial derivatives related to physical emissions.

**Environmental Protection Agency (EPA) Rules**

**Cross-State Air Pollution Rule**

In April 2014, the U.S. Supreme Court upheld the EPA's CSAPR, which is designed to set limits on emissions from power plants in 28 states in the eastern half of the United States via a cap-and-trade program. The EPA is currently reviewing the Supreme Court’s opinion but has not yet indicated whether it plans to move forward with its efforts to reinstate the CSAPR. Meanwhile, the Clean Air Interstate Rule (CAIR) remains in effect. The CAIR regulates emissions of SO₂ and NOₓ from power plants, seeking to limit particles that drift from one state to another. The CAIR's cap-and-trade system, which covers 27 eastern states and the District of Columbia, allows the states to meet their individual emissions budgets by selecting one of two compliance options: (1) requiring power plants to participate in an EPA-administered interstate cap-and-trade system that caps emissions in two stages or (2) undertaking measures of their own choosing.

**Clean Power Plan**

In June 2014, the EPA proposed the CPP, a comprehensive plan designed to reduce existing emissions by fossil-fuel electric-generating-unit (EGU) plants. Under the CPP, by the year 2030, carbon emissions within the power sector would be reduced by about 30 percent compared with 2005 levels. The CPP is also expected to reduce other particle pollution, as well as NOₓ and SO₂ levels, by about 25 percent. While the CPP is expected to result in a collaborative effort at the federal and state levels, the onus of complying with the CO₂ emissions mandate will be greater with the states, each of which will need to develop a specific state implementation plan by considering its (1) existing emissions reduction strategies; (2) energy resources; (3) operational efficiencies; and (4) energy, environmental, and economic needs.

**Market Activity**

**Coal**

Coal prices in the United States have remained competitive with natural gas prices. The spot price for high-grade, low-sulfur Central Appalachian coal increased by 12 percent, from about $53 per ton in the third quarter of 2013 to about $60 per ton in the third quarter of 2014. Similarly, the spot price for low-grade, high-sulfur Powder River Basin coal increased by 14 percent, from about $9 per ton in the third quarter of 2013 to about $12 per ton in the third quarter of 2014. However, increasing regulatory constraints are causing power producers to gradually turn their attention from coal to natural-gas-fired generation capacity.

In addition, power producers have been moving away from long-term contractual arrangements with coal suppliers and entering into shorter-term supply contracts. Reasons for this shift include (1) concerns about supply-chain reliability as a result of constraints related to the long-haul railroad transportation of coal and (2) increasing regulatory burden. The
increase in shorter-term delivery contracts has caused spot coal deliveries to increase from about 6 percent of the total coal supplied in 2013 to about 11 percent in 2014. The reliability issues in coal supply have also introduced increasing volatility in the coal spot markets.

According to the EIA, four factors will continue to help gas displace coal in the long term: efficiency, flexibility, competitiveness, and regulation. Consequently, companies with coal-generation assets continue to focus on the accounting implications of coal displacement. Coal inventories may also continue to increase as forward demand weakens, triggering consideration of lower-of-cost-or-market (LCM) analysis and possible impairment.

Companies that enter into coal transactions should continue to be mindful of the following:

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

- **Impairment of coal generation assets, coal inventories, or both** — Coal generation may be displaced as the transition to natural gas occurs, which could have implications for the economic useful life of generation assets and related inventories. Trending price increases decrease the likelihood of inventory LCM adjustments. However, this same trend may contribute to the decisions to displace coal with cheaper generation and therefore has impairment implications for coal generation assets.

**Natural Gas**

U.S. natural gas prices have continued to increase over the past year. Henry Hub prices have risen by about 6 percent, from about $3.68 per MMbtu to about $3.92 per MMbtu. These prices are forecasted to stabilize as a result of an overall shift in shale-gas activity from drilling to production.

Current environmental regulatory trends, combined with the proliferation of shale gas, have created a situation in which power producers are increasingly retrofitting generators to adapt to natural-gas-fired technology. Natural-gas storage deficits and midstream capacity constraints will continue to play an important role in the pricing of natural gas in the medium term. Gas continues to behave like a local commodity because of these constraints. Short-term volatilities, infrastructure constraints, and evolving market locations all continue to contribute to the complexity of fair value accounting. Historical relationships and location basis assumptions have required updated analysis and can make it challenging to ensure that current market conditions have been appropriately reflected.

**Readily-Convertible-to-Cash Considerations (RCC) Related to Natural Gas Liquids and Liquefied Natural Gas**

**Natural Gas Liquids**

Natural gas and related commodities (e.g., natural gas liquids) continue to be treated as local commodities because of storage deficits and limitations in pipeline capacity. Currently, transportation costs tend to make up a material portion of the prices realized for the delivered gas, thereby preventing most companies from concluding that delivered products are RCC. However, as midstream infrastructure improves in the medium term and commercially viable markets develop, RCC conclusions will need to be revisited.

**Liquefied Natural Gas**

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

Historically, the United States has imported LNG through regasification facilities located on the East and Gulf Coasts. The development of these facilities was supported by the $12 per MMBtu natural gas prices in 2008. However, given the $3 to $4 prices for 2013 and 2014, along with the increased supply of shale gas, regasification facilities have begun to convert from regasification to liquefaction in anticipation of LNG export. The U.S. LNG export licensing process is administered by the Department of Energy (DOE) under the Natural Gas Act. To speed up the licensing process, the DOE has begun to prioritize projects on the basis of their merits. With low-cost players already in the market, at least some of the U.S. LNG players are considering entering into tolling arrangements to deliver LNG to international markets.

Despite this trend in activity, the market for bilateral LNG forwards has remained very small. Broker-dealer markets have been slow to develop for LNG, and there are still no exchange-traded LNG contracts. Therefore, most companies would conclude that LNG contracts are not RCC.

Companies with LNG transactions are encouraged to keep up to date with their RCC conclusions as the market continues to evolve.

**Alternative to Hedge Accounting**

While a revisit of hedge accounting has been on the financial instruments convergence agenda for some time, differences between the FASB’s and IASB’s views have stalled momentum. Given the complexity and administrative burden of applying hedge accounting, fewer and fewer companies have been electing to do so. Instead, the use of non-GAAP financial measures to explain or discuss operating and economic performance has continued to grow in popularity. Although non-GAAP financial measures may serve a similar purpose and enable companies to avoid applying hedge accounting, companies using these measures may be required to provide some additional disclosures to avoid misleading financial statement users.

**Regulation G — Disclosures About Non-GAAP Financial Measures**

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

**Bundled Contracts**

**Contract Assessment Considerations**

Although electricity procurement is typically the primary purpose of a power purchase, renewable energy contracts often include RECs along with the energy output. These types of contracts are often referred to as bundled contracts. In accounting for such contracts, a selling entity should consider the guidance in the FASB’s and IASB’s new revenue standard (codified in ASC 606).1

Specifically, P&U entities should carefully evaluate their contracts with customers for multiple products and services and assess whether (1) products or services separated in accordance with the guidance in other Codification topics should

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1 For more information about the boards’ new revenue standard, see Deloitte’s May 28, 2014, Heads Up as well as Introducing a New Revenue Model below. Also see Deloitte’s August 2014 Power & Utilities Spotlight for issues and potential challenges that may be particularly relevant for P&U entities.
be accounted for under ASU 2014-09 or (2) an entity should apply ASU 2014-09’s guidance on distinct performance obligations when separating multiple products and services in contracts with customers. While the new guidance is not expected to significantly change current practice for rate-regulated operations, P&U entities will need to consider the new standard and revisit their accounting for bundled arrangements.

Other relevant Codification topics that may affect bundled contracts include the following:

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

- **Derivative accounting** — To the extent that an element in a bundled arrangement is considered a nonlease element, entities would need to assess it to determine whether it meets the derivative requirements. Because ASC 815-15 does not specify how to identify a host for executory contracts with multiple elements, two views on identifying the host contract in a bundled arrangement have developed in the P&U industry:
  - **Predominant characteristics** — In this view, the host is defined as the portion of the contract that embodies the most significant economics under the transaction on the basis of the relative value contribution of the various contract elements. For bundled electricity contracts, electricity is often (but not always) the element with the most significant value and thus is defined as the host; therefore, the entire contract (including any potential nonderivative elements) would be deemed a derivative contract and fair value would be assessed for the entire contract. While we believe that this approach is fairly common in practice, we also think that it increases accounting risk and that reporting entities should consult with their auditors about whether this approach continues to be acceptable.
  - **Nonderivative host** — In this view, the host is defined as the portion of the contract that does not meet the derivative criteria. For example, the host contract in a bundled contract containing both electricity and RECs would be the REC element (as long as the REC element does not qualify as a derivative), and an entity would assess whether the electricity forward needs to be bifurcated. If the electricity portion of the contract must be bifurcated, reporting entities are permitted to elect the NPNS scope exception for embedded derivatives under ASC 815-15-55-21 (as long as the appropriate criteria are met). It would be rare for an entity to recognize an inception gain or loss as a result of bifurcating an embedded derivative.

**RTO (Regional Transmission Operator) or ISO (Independent System Operators) Considerations**

As discussed in Normal Purchases and Normal Sales Scope Exception (NPNS) above, the EEI submitted an inquiry to the SEC regarding NPNS eligibility for certain forward electricity transactions in nodal markets. The inquiry focuses on whether the NPNS scope exception can be applied to a forward power contract for physical delivery in a nodal market operated by an ISO when the delivery point of the forward contract differs from the location of the purchaser’s customers. Views on this topic differ. While some companies continue not to elect the NPNS scope exception for their derivative contracts, others believe that the exception should be applied to eligible contracts regardless of ISO considerations. The FASB’s decision on this topic is expected to significantly affect energy-contract accounting performed through an ISO.

This issue has also prompted companies to consider whether they need to establish new, or enhance existing, controls for relevant processes. For example, companies are taking a fresh look at how ISO- and RTO-related transactions are presented on the income statement and in other regulatory reporting.

**Gross/Net Income Statement Presentation**

The RTO is responsible for creating an exchange to match low-cost energy with load requirements. Each RTO does this by acting as the transmission system operator responsible for reliably and economically dispatching generation to meet
system load requirements. RTOs manage energy supply and demand on a pool basis (i.e., because energy is a nonstorable commodity). Because power is a commodity in which one MW cannot be distinguished from another, generators of electricity cannot clearly see the final destination of their electricity when it is sold into the RTO pool.

Because energy cannot be stored, a company must either sell excesses or purchase shortfalls, which creates numerous RTO-governed purchase and sale transactions. The accounting for these transactions, which may occur hourly or more frequently, is complex since a company must present both sales into and purchases out of the RTO. Given the shift of various jurisdictions away from a traditional vertically integrated model to an RTO-centric model, P&U companies should ensure that they have appropriate policies in place to account for sales and purchase transactions with the RTO both for U.S. GAAP purposes and to comply with the FERC chart of accounts. If a P&U company has multiple subsidiaries, the company should ensure that policies implemented at the subsidiary level are consistently applied at the consolidated level.

Volumetric Data

The shift of certain jurisdictions away from a traditional vertically integrated model to an RTO-centric model also places demands on owners of transmission assets to supply accurate volumetric data to the RTOs to settle sales and purchase transactions with the RTO or between counterparties. Volumetric data responsibilities of the P&U company can include transmission-level load data or carve-outs of distribution-load information in deregulated markets. Often, companies’ procedures for this process are manual and reviews are limited before data are submitted. P&U companies should ensure they have appropriate controls in place to confirm the accuracy of volumetric data sent into and withdrawn from the RTO.
Section 6
Accounting Standards Codification Update
Reporting of Discontinued Operations

On April 10, 2014, the FASB issued ASU 2014-08, which amends the definition of a discontinued operation in ASC 205-20 and requires entities to provide additional disclosures about disposal transactions that do not meet the discontinued-operations criteria. In addition to changing how entities identify and disclose information about disposal transactions under U.S. GAAP, the ASU elevates the threshold under which a disposal transaction qualifies as a discontinued operation (since too many disposal transactions were qualifying as discontinued operations under existing guidance).

Under the previous guidance in ASC 205-20-45-1, the results of operations of a component of an entity were classified as a discontinued operation if all of the following conditions were met:

- The component “has been disposed of or is classified as held for sale.”
- “The operations and cash flows of the component have been (or will be) eliminated from the ongoing operations of the entity as a result of the disposal transaction.”
- “The entity will not have any significant continuing involvement in the operations of the component after the disposal transaction.”

The new guidance eliminates the second and third criteria above and instead requires discontinued-operations treatment for disposals of a component or group of components that represents a strategic shift that has or will have a major impact on an entity’s operations or financial results.

Whether a P&U entity disposes of a reportable segment, an operating segment, a subsidiary, or another component, the disposal’s importance to the entity and financial statement users is critical to whether the disposal represents a strategic shift. Given the ASU’s lack of clarity on this topic, a P&U entity will need to use judgment in determining whether a strategic shift has occurred.

Scope

The ASU retains the discontinued-operations scope exception for oil and gas properties accounted for under the full-cost method but removes the exceptions in ASC 360-10-15-5 (e.g., the exception in ASC 360-10-15-5(e) for investments in equity securities accounted for under the equity method). Further, unlike current U.S. GAAP, the ASU includes “a business or nonprofit activity that, on acquisition, meets the criteria to be classified as held for sale” in the definition of a discontinued operation.

Presentation and Disclosure

The ASU (1) expands disclosure requirements for transactions that meet the definition of a discontinued operation and (2) requires entities to disclose information about individually significant components that are disposed of or held for sale and do not qualify as discontinued operations.

In addition, the ASU requires entities to reclassify assets and liabilities of a discontinued operation for all comparative periods presented in the statement of financial position. Before these amendments, ASC 205-20 neither required nor prohibited such presentation.

Further, regarding the statement of cash flows, an entity must disclose, in all periods presented, either (1) operating and investing cash flows or (2) depreciation and amortization, capital expenditures, and significant operating and investing
noncash items related to the discontinued operation. This presentation requirement represents a significant change from previous guidance.

See Deloitte’s April 22, 2014, Heads Up for further discussion of the ASU 2014-08 disclosure requirements.

Effective Date and Transition
The ASU is effective prospectively for all disposals (except disposals classified as held for sale before the adoption date) or components initially classified as held for sale in periods beginning on or after December 15, 2014. Early adoption is permitted.

Going Concern
On August 27, 2014, the FASB issued ASU 2014-15, which contains guidance on (1) how to perform a going-concern assessment and (2) when and how to disclose going-concern uncertainties in the financial statements.

Under U.S. GAAP, an entity’s financial reports reflect its assumption that it will continue as a going concern until liquidation is imminent. However, before liquidation is deemed imminent, an entity may have uncertainties about its ability to continue as a going concern. Because there are no current U.S. GAAP requirements related to disclosing such uncertainties, auditors have used applicable auditing standards to assess the nature, timing, and extent of an entity’s disclosures. The ASU is intended to reduce the diversity in practice that has resulted from this lack of specific going-concern disclosure requirements.

Time Horizon
In each reporting period (including interim periods), an entity is required to assess its ability to meet its obligations as they become due for one year after the issuance date of the financial statements.

Disclosures
An entity must provide certain disclosures if “conditions or events raise substantial doubt about [the] entity’s ability to continue as a going concern.” The ASU defines substantial doubt as follows:

Substantial doubt about an entity’s ability to continue as a going concern exists when conditions and events, considered in the aggregate, indicate that it is probable that the entity will be unable to meet its obligations as they become due within one year after the date that the financial statements are issued . . . . The term probable is used consistently with its use in Topic 450 on contingencies.

In applying this disclosure threshold, an entity must evaluate “relevant conditions and events that are known and reasonably knowable at the date that the financial statements are issued.” Reasonably knowable conditions or events are those that can be identified without undue cost and effort.

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1 In accordance with ASC 205-30, an entity must apply the liquidation basis of accounting once liquidation is deemed imminent.
2 PCAOB AU Section 341, The Auditor’s Consideration of an Entity’s Ability to Continue as a Going Concern.
If an entity triggers the substantial-doubt threshold, its footnote disclosures must contain the following information, as applicable:

<table>
<thead>
<tr>
<th>Substantial Doubt Is Raised but Is Alleviated by Management’s Plans</th>
<th>Substantial Doubt Is Raised but Is Not Alleviated</th>
</tr>
</thead>
<tbody>
<tr>
<td>• Principal conditions or events.</td>
<td>• Principal conditions or events.</td>
</tr>
<tr>
<td>• Management’s evaluation.</td>
<td>• Management’s evaluation.</td>
</tr>
<tr>
<td>• Management’s plans.</td>
<td>• Management’s plans.</td>
</tr>
<tr>
<td>• Statement that there is “substantial doubt about [the] entity’s ability to continue as a going concern.”</td>
<td></td>
</tr>
</tbody>
</table>

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

**Effective Date**

The guidance in the ASU is “effective for annual periods ending after December 15, 2016, and interim periods within annual periods beginning after December 15, 2016.” Early application is permitted.

For additional information about the going-concern ASU, see Deloitte’s August 28, 2014, *Heads Up.*

**Development-Stage Entities**

On June 10, 2014, the FASB issued ASU 2014-10, which eliminates the concept of a development-stage entity (DSE) from U.S. GAAP. Specifically, the ASU removes:

- ASC 915 in its entirety, which contained presentation and disclosure requirements related to DSEs (e.g., inception-to-date information).
- The guidance in ASC 810 on evaluating whether a DSE has sufficient equity at risk (one of the criteria for determining whether an entity is a VIE).

The ASU also clarifies that the disclosure requirements in ASC 275 (i.e., disclosures about risks and uncertainties) apply to entities that have “not commenced planned principal operations.”

ASU 2014-10 could affect P&U entities with investees that currently qualify as DSEs under ASC 915 (e.g., P&U entities involved in the beginning stages of constructing a renewable or fossil fuel generation asset). P&U entities with interests in DSEs will have to assess their consolidation of such entities. Further, even if a P&U entity with an interest in a DSE determines that it does not need to consolidate the entity, it will need to provide disclosures if it has a variable interest in the entity.

Except for the amendments to ASC 810, the ASU is effective for (1) reporting periods (including interim periods) beginning after December 15, 2014, for public business entities and (2) annual periods beginning after December 15, 2014, and interim periods beginning after December 15, 2015, for other entities. The amendments to ASC 810 are effective one year later for public business entities and two years later for other entities. Early adoption of the amendments is permitted for “any annual reporting period or interim period for which the entity’s financial statements have not yet been issued.”

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1. The Codification Master Glossary defines a DSE as “an entity devoting substantially all of its efforts to establishing a new business and for which either of the following conditions exists: (a) planned principal operations have not commenced; (b) planned principal operations have commenced, but there has been no significant revenue therefrom.”

2. The ASU notes that users of DSE financial statements do not find “the [DSE] distinction, the inception-to-date information, and certain other disclosures that DSEs are currently required to provide to be decision useful.”
Service Concession Arrangements

On January 23, 2014, the FASB issued ASU 2014-05 in response to the final consensus on Issue 12-H reached by the EITF at its November 2013 meeting. The ASU prohibits an operating entity from accounting for certain service concession contracts as a lease under ASC 840 and from recognizing a grantor’s infrastructure (e.g., transmission or distribution assets of a municipality) as property, plant, or equipment in its statement of financial position. Entities should consult other ASC topics for guidance on accounting for various components of a service concession contract (e.g., the guidance in ASC 605 on recognizing revenue resulting from the operating entity’s performance under a service concession contract).

Scope

ASU 2014-05 affects operating entities that enter into service concession contracts with a public-sector entity grantor to provide a public service by operating the grantor’s infrastructure. To qualify as a service concession arrangement, an arrangement must meet both of the following criteria:

1. The grantor controls or has the ability to modify or approve the services that the operating entity must provide with the infrastructure, to whom it must provide them, and at what price.
2. The grantor controls, through ownership, beneficial entitlement, or otherwise, any residual interest in the infrastructure at the end of the term of the arrangement.

P&U entities should carefully evaluate whether they have relationships with any governmental entities (e.g., counties, states, municipalities, public service commissions) in which services are provided on behalf of, or with, these entities. (However, this evaluation would not take into account relationships with regulators that are within the scope of ASC 980.) When such relationships qualify as service concession arrangements by meeting both of the above criteria, P&U entities will need to reassess their treatment of the related contracts and their effects on the financial statements.

Transition and Effective Date

The guidance in the ASU is effective for public business entities for fiscal years beginning after December 15, 2014, and interim periods therein. For other entities, the ASU is effective for annual periods beginning after December 15, 2014, and interim periods within annual periods beginning after December 15, 2015. Early adoption is permitted. Entities will apply the guidance “on a modified retrospective basis to service concession arrangements that exist at the beginning of an entity’s fiscal year of adoption” and will recognize the cumulative effect of any income-statement effects as an adjustment to beginning retained earnings.

Pushdown Accounting

On November 18, 2014, the FASB issued ASU 2014-17 in response to the final consensus on Issue 12-F reached by the EITF at its September 2014 meeting. Under the ASU, an acquired entity has the option of applying pushdown accounting (i.e., establishing a new accounting and reporting basis) in its stand-alone financial statements upon a change-in-control event. Specifically, an acquired entity that elects pushdown accounting would apply the measurement principles in ASC 805 to push down the measurement basis of its acquirer to its stand-alone financial statements. In addition, the acquired entity would be required to provide disclosures that enable financial statement users “to evaluate the nature and effect of the pushdown accounting.”

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1 See Deloitte’s November 2013 EITF Snapshot for additional information about EITF Issue 12-H.
2 Service concession arrangements within the scope of ASC 980 are outside the scope of ASU 2014-05 and should continue to be accounted for under ASC 980.
3 The ASU’s scope includes both public and nonpublic acquired entities, regardless of whether such an entity is a business or a nonprofit activity.
4 Entities would achieve that disclosure objective by providing the relevant disclosures required by ASC 805.
Under ASU 2014-17, when an acquired entity elects to apply pushdown accounting, it would be:

- Prohibited from recognizing acquisition-related debt incurred by the acquirer unless the acquired entity is required to do so in accordance with other applicable U.S. GAAP (e.g., because the acquired entity is legally obligated).
- Required to recognize the acquirer’s goodwill.
- Prohibited from recognizing bargain purchase gains that resulted from the change-in-control transaction or event. However, the acquired entity would treat the bargain purchase gain as an adjustment to equity (i.e., additional paid-in capital).

ASU 2014-17 also clarifies that the subsidiary of an acquired entity would have the option of applying pushdown accounting to its stand-alone financial statements even if the acquired entity (i.e., the direct subsidiary of the acquirer) elected not to apply pushdown accounting.

In connection with the issuance of ASU 2014-17, the SEC has rescinded SAB Topic 5.J, which contained the SEC staff’s views on how SEC registrants should apply pushdown accounting. Thus, all entities—regardless of whether they are SEC registrants—will now apply the guidance in ASU 2014-17.

The ASU’s amendments became effective upon issuance.

Under the ASU, P&U entities would have greater flexibility in determining when to apply pushdown accounting. In their assessment, entities should consider the underlying needs of their financial statement users and whether regulatory requirements differ from those in the ASU’s guidance (i.e., whether regulatory reports restrict use of pushdown accounting).

**Consolidation**

The FASB is currently finalizing its forthcoming ASU on consolidation. While the Board’s deliberations have largely focused on the investment management industry, its decisions could have a significant impact on P&U entities’ consolidation conclusions. Specifically, the amended guidance could affect a P&U entity’s evaluation of whether (1) limited partnerships and similar entities should be consolidated and (2) variable interests held by the P&U entity’s related parties or de facto agents affect its consolidation conclusion. P&U entities will need to reevaluate their previous consolidation conclusions in light of their involvement with current VIEs, limited partnerships not previously considered VIEs, and entities previously subject to the deferral in ASU 2010-10.

For additional information about the FASB’s consolidation deliberations, see Deloitte’s October 7, 2014, Heads Up.

**Limited Partnerships (and Similar Entities)**

**Determining Whether a Limited Partnership Is a VIE**

The definition of a VIE would be amended only for limited partnerships and similar entities. Under the ASU, a limited partnership would be considered a VIE regardless of whether it has sufficient equity or meets the other requirements to qualify as a voting interest entity, unless either (1) a single LP or a simple majority or lower percentage of the limited partners—excluding interests held by the GP, by entities under common control of the GP, and by other entities acting on behalf of the GP—has substantial kick-out rights (including liquidation rights) or (2) LPs with equity at risk are able to exercise substantive participating rights over the GP. As a result of the proposed amendments to the definition of a VIE for limited partnerships and similar entities, partnerships that historically were not considered VIEs may need to be evaluated under the new VIE consolidation model. Although the consolidation conclusion may not change, an updated analysis on the basis of the revised guidance would be required. In addition, even if a reporting entity determines that it does not need to
Consolidation of a Limited Partnership

Under current U.S. GAAP, a GP is required to perform an evaluation under ASC 810-20 to determine whether it controls a limited partnership that is not considered a VIE. This evaluation focuses on whether certain rights held by the unrelated LPs are substantive and overcome the presumption that the GP controls (and therefore is required to consolidate) the partnership. To overcome the presumption that the GP controls the partnership, the LPs (excluding interests held by the GP, by entities under common control of the GP, and by other entities acting on behalf of the GP) must have either (1) the substantive ability to dissolve (liquidate) the limited partnership or otherwise remove the GP without cause or (2) substantive participating rights.

Like an entity's analysis under the current guidance in ASC 810-20, its analysis under the proposed guidance on determining whether the GP should consolidate a partnership that is not considered a VIE would focus on an evaluation of whether the kick-out, liquidation, or participating rights held by the other partners are considered substantive. The rights would be considered substantive if they can be exercised by a simple majority of all of the partnership interests, excluding the interests held by the GP, by entities under common control of the GP, and by other entities acting on behalf of the GP.

Partnerships that do not have substantive kick-out rights (including liquidation rights) or substantive participating rights would be VIEs. The evaluation of whether the GP should consolidate a limited partnership (or similar entity) that is considered a VIE is consistent with how all other VIEs would be analyzed (i.e., the GP's power over the VIE and the GP's economic exposure to the VIE would be considered). Accordingly, the GP would generally not be required to consolidate a limited partnership if the partners do not have substantive kick-out rights (including liquidation rights) or substantive participating rights unless the GP (or an entity under common control of the GP) has an interest in the partnership that could potentially be significant.

Identifying the Primary Beneficiary of a VIE

The FASB tentatively decided that in a manner consistent with the requirements in ASU 2009-17, a variable interest holder would be considered the primary beneficiary of a VIE (and would therefore be required to consolidate the VIE) when it has (1) the power to direct the activities of the VIE that most significantly affect the VIE's performance and (2) the obligation to absorb losses of, or the right to receive benefits from, the VIE that could potentially be significant to the VIE.

In addition, the FASB tentatively decided that when a decision maker evaluates its economic exposure to a VIE, it should consider its direct interests in the VIE together with its indirect interests held through its related parties (or de facto agents) on a proportionate basis. This approach is consistent with that in the FASB's November 2011 exposure draft (ED), which includes the following two examples of this concept:

- “[I]f a decision maker owns a 40 percent interest in a related party and that related party owns a 60 percent interest in the entity being evaluated, the decision maker’s interest would be considered equivalent to a 24 percent direct interest in the entity for the purposes of evaluating its decision-making capacity (assuming it has no other relationships with the entity).”

- “[I]f an employee of the decision maker is a related party and owns an interest in the entity being evaluated and that employee's interest has been financed by the decision maker, the decision maker shall include its indirect interest in the evaluation.”

However, the Board also decided that depending on the “nature and substance of the related party relationship,” a decision maker may conclude that it should consider its related party's interests as though it holds them directly (similar to the existing guidance in ASC 810). Specifically, the FASB indicated that if the reporting entity and its related party are under common control, the related party’s entire economic interest should be included in the reporting entity’s analysis of whether (1) it has a variable interest in the entity and (2) it is the primary beneficiary of the VIE.
Effects of Related Parties

Under the requirements in ASU 2009-17, when a related-party relationship exists,\(^9\) each party in the related-party group must first determine whether it has the characteristics of a controlling financial interest (ASC 810-10-25-38A) in the VIE. If none of the parties in the related-party group have the characteristics of a controlling financial interest individually, but the related-party group as a whole has these characteristics, the reporting entity must consider the factors in ASC 810-10-25-44 to determine which party in the group is the primary beneficiary and, therefore, the party that must consolidate the VIE (this analysis is commonly referred to as the “related-party tiebreaker test”). In addition, parties in the related-party group (including de facto agents) cannot conclude that power is shared and instead must identify one of the parties as the primary beneficiary of the VIE.

The FASB tentatively decided that in a manner consistent with these requirements, each party in a related-party group must first determine whether it individually has the characteristics of a controlling financial interest in the VIE. The FASB also decided to retain the current guidance under which parties in a related-party group (including de facto agents) cannot conclude that they do not individually have these characteristics because they consider power to be shared among them. Accordingly, when power is considered “shared,” the related parties would be required to perform the related-party tiebreaker test to identify the party in the group that is most closely associated with the VIE.

If power is not considered shared among the related parties, the related-party tiebreaker test would be performed only by parties in the decision maker’s related-party group that are under common control and that together possess the characteristics of a controlling financial interest. In this situation, the purpose of the test would be to determine whether the decision maker or a related party under common control of the decision maker is required to consolidate the VIE.

The FASB also tentatively decided that if neither the decision maker nor a related party under common control is required to consolidate a VIE but the related-party group (including de facto agents) possesses the characteristics of a controlling financial interest and substantially all of the VIE’s activities are conducted on behalf of a single entity in the related-party group, that entity would be the primary beneficiary of the VIE.

Effective Date and Transition

Modified retrospective application (including a practicability exception) would be required; full retrospective application would be optional. For public business entities, the ASU’s guidance would be effective for annual periods, and interim periods within those annual periods, beginning after December 15, 2015. For entities other than public business entities, the ASU’s guidance would be effective for annual periods beginning after December 15, 2016, and interim periods beginning after December 15, 2017. The ASU would allow early adoption for all entities but would require entities to apply its guidance as of the beginning of the annual period containing the adoption date.

P&U entities should start considering the extent to which they may need to change processes and controls to apply the revised guidance, including those related to obtaining additional information that may have to be provided under the disclosure requirements. Changing such processes and controls may be particularly challenging for entities that intend to early adopt the proposed guidance. In addition, companies should consider the effect of the revised guidance as they enter into new transactions.

Leases

The FASB has been working with the IASB for almost a decade to address concerns related to the off-balance-sheet treatment of certain lease arrangements by lessees. The boards’ proposed model would require lessees to adopt an ROU asset approach that would bring substantially all leases, with the exception of short-term leases (i.e., those with a lease term of 12 months or less), on the balance sheet. Under this approach, a lessee would record (1) an ROU asset representing its right to use the underlying asset during the lease term and (2) a corresponding lease liability.

\(^9\) The term “related parties” encompasses parties identified as related parties in ASC 850 and certain other parties described in ASC 810-10-25-43 that are considered de facto agents of the reporting entity.
The boards have spent a significant amount of time trying to define a lease arrangement to help entities determine whether an arrangement contains a lease or represents an agreement to provide a service. The boards’ revised leases ED, released by the FASB as a proposed ASU in May 2013, defines a lease as “a contract that conveys the right to use an asset (the underlying asset) for a period of time in exchange for consideration.” The revised ED focuses on whether (1) the contract is based on an identified asset and (2) the lessee obtains the right to control the use of the asset for a particular period. The definition in the revised ED represented a significant departure from the current guidance in ASC 840, under which a customer’s control of the outputs of an identified asset is considered sufficiently representative of a lease of that asset (e.g., a power purchase agreement, in which the off-taker purchases substantially all of the outputs of a generating facility).

The definition of “control” in the consolidation guidance will not carry over to the new leases standard. In addition, the boards’ final definition of a lease may have a significant impact on whether an arrangement is within the scope of the new guidance. For example, the boards have not yet determined how an entity will consider dispatch rights when assessing whether a lease exists. Similarly, while the fact that a customer is a plant operator may affect the lease determination, it may not be the deciding factor.

Lessee Accounting

While the FASB and IASB agree that a lessee should record an ROU asset and a corresponding lease liability when the lease commences, the boards support different approaches for the lessee’s subsequent measurement of the ROU asset. The FASB decided on a dual-model approach under which a lessee would classify a lease in accordance with criteria similar to the current lease classification criteria in IAS 17, while the IASB decided on a single-model approach under which lessees would account for all leases in a manner similar to a financed purchase arrangement.

Under the FASB’s approach, the lessee would account for a “Type A” lease (many current capital leases are expected to qualify as Type A) in a manner similar to a financed purchase arrangement. That is, the lessee would recognize interest expense and amortization for the ROU asset, which typically would result in a greater expense during the early years of the lease. For “Type B” leases (many current operating leases are expected to qualify as Type B), the lessee would recognize a straight-line total lease expense. For both Type A and Type B leases, the lessee would recognize (1) an ROU asset for its interest in the underlying asset and (2) a corresponding lease liability.

Unlike the current criteria in ASC 840, the lease classification criteria in IAS 17 are not “bright lines.” Therefore, it is possible that operating leases that currently meet the bright-line criteria in ASC 840 could be considered Type A leases under the FASB’s proposed dual-model approach. P&U entities would need to carefully reassess their lease classifications and consider whether this reassessment could affect their patterns of expense recognition.

Lessor Accounting

Earlier this year, the boards discussed constituents’ feedback on the ED and decided not to make significant changes to the existing lessor accounting model. Rather, they agreed to adopt an approach similar to the existing capital/finance lease and operating lease models in ASC 840 and IAS 17. However, the FASB decided to align the U.S. GAAP classification requirements with the criteria in IAS 17. In addition, the FASB decided that for leases that are similar to current sales-type leases, the lessor would only be permitted to recognize the profit on the transaction if the arrangement would have qualified as a sale under the new revenue recognition guidance (ASC 606).

Next Steps

The FASB and IASB are expected to complete their redeliberations of the proposed lease guidance in early 2015 and, although they have not indicated a release date, are likely to issue final guidance during the second half of 2015. Likewise, although the boards have not indicated when the final guidance would be effective, a date as early as January 1, 2018, is possible. See Deloitte’s March 27, 2014, Heads Up for additional information about the boards’ tentative decisions regarding the proposed lessee and lessor accounting models.
Lease accounting changes could have a significant impact on P&U entities, including their:

- **Systems** — For instance, a P&U entity may need to implement an IT system to maintain lease activity or update its legacy systems in light of the new standard.

- **Business decisions** — Examples of business decision changes include (1) evaluation of existing debt covenants to ensure that no new liabilities are in violation of the covenant and (2) more careful scrutiny of “lease vs. buy” decisions.

- **Financial reporting** — New model will result in increased disclosures and a need to use greater judgment in determining whether an arrangement contains a lease and whether such a lease should be classified as Type A or Type B.

## Financial Instruments — Classification and Measurement

### Recent Redeliberations

The FASB is no longer pursuing an approach to the classification and measurement of financial instruments that would be converged with the IASB’s model. Instead, the Board has decided to retain existing requirements related to (1) the classification and measurement categories for financial instruments other than equity investments, (2) the method for classifying financial instruments, (3) bifurcation of embedded derivatives in hybrid financial assets, and (4) accounting for equity method investments (including impairment of such investments). In addition, the Board has discussed making targeted improvements to the requirements related to accounting for equity investments and presenting certain fair value changes with respect to fair value option liabilities.

### Classification and Measurement of Equity Investments

Under the FASB’s tentative approach, entities would be required to carry all investments in equity securities that do not qualify for the equity method or a practicability exception at fair value through net income (FVTNI). For equity investments that do not have a readily determinable fair value, the FASB would permit entities to elect the practicability exception to fair value measurement. Under this exception (which is not available to reporting entities that are investment companies or broker-dealers), the investment would be measured at cost less impairment plus or minus observable price changes.

### Thinking It Through

The FASB has not addressed industry concerns about the accounting for decommissioning trusts used by P&U entities with nuclear and other decommissioning obligations. Under the FASB’s tentative approach, instruments other than equity investments held by these funds may be classified and measured as fair value through other comprehensive income (FVTOCI); however, this option would no longer be available for the equity investments themselves. Both the EEI and the AGA raised this issue in their joint comment letter to the FASB about the Board’s February 2013 ED.

### Impairment Assessment of Equity Investments That Are Measured by Using the Practicability Exception

In an effort to simplify the impairment model for equity securities for which an entity has elected the practicability exception, the FASB has tentatively decided to eliminate the requirement to assess whether an impairment of such an investment is other than temporary. In each reporting period, an entity would qualitatively consider certain indicators to determine whether the investment is impaired, including:

a. A significant deterioration in the earnings performance, credit rating, asset quality, or business prospects of the investee
b. A significant adverse change in the regulatory, economic, or technological environment of the investee

c. A significant adverse change in the general market condition of either the geographic area or the industry in which the investee operates

d. A bona fide offer to purchase, an offer by the investee to sell, or a completed auction process for the same or similar investment for an amount less than the cost of that investment

e. Factors that raise significant concerns about the investee’s ability to continue as a going concern, such as negative cash flows from operations, working capital deficiencies, or noncompliance with statutory capital requirements or debt covenants.

An entity that determines that the equity security is impaired on the basis of an assessment of the above indicators would recognize an impairment loss equal to the difference between the security’s fair value and carrying amount. In contrast, the existing guidance in ASC 320-10-35-30 requires entities to perform a two-step assessment under which an entity first determines whether an equity security is impaired and then evaluates whether any impairment is other than temporary.

### Thinking It Through

Under existing U.S. GAAP, marketable equity securities other than equity method investments (those for which the investor has significant influence over the investee) are classified as either held for trading (FVTNI) or available for sale (FVTOCI). For available-for-sale equity securities, any amounts in AOCI are recycled to net income upon sale or an other-than-temporary impairment. Investments in nonmarketable equity securities other than equity method investments are measured at cost (less impairment) unless the fair value option has been elected. Because equity securities can no longer be accounted for as available-for-sale securities or by using the cost method, P&L entities that hold such equity investments could see more volatility in earnings under the proposed guidance.

### Presentation of Fair Value Changes Attributable to Instrument-Specific Credit Risk for Fair Value Option Liabilities

The FASB has tentatively decided to introduce a new requirement related to the presentation of fair value changes associated with financial liabilities for which the fair value option has been elected. Under this tentative decision, an entity would be required to separately recognize in OCI the portion of the total fair value change attributable to instrument-specific credit risk. For derivative liabilities, however, any changes in fair value attributable to instrument-specific credit risk would continue to be presented in net income.

Under the FASB’s tentative approach, an entity would measure the portion of the change in fair value attributable to instrument-specific credit risk as the excess of the total change in fair value over the change in fair value “resulting from a change in a base market risk, such as a risk-free interest rate.” However, “an entity may use [an alternative] method that it considers to more faithfully represent the portion of the total change in fair value resulting from a change in instrument-specific credit risk.” In either case, the entity would be required to disclose the method it “used to determine the gains and losses attributable to instrument-specific credit risk and [to] apply the method consistently from period to period.”

See Appendix A in Deloitte’s August 8, 2014, Heads Up for a tabular comparison between classification and measurement models under current U.S. GAAP and those under the FASB’s tentative approach.

### Next Steps

Classification and measurement topics that the Board plans to discuss at future meetings include disclosures (e.g., core deposits), transition, effective date, and cost-benefit considerations.
Financial Instruments — Hedging

At its November 5, 2014, meeting, the FASB voted to move its current research project on hedge accounting to its active agenda. In deliberating the project, the FASB will discuss the following issues:

- Hedge effectiveness requirements.
- Whether the shortcut and critical-terms-match methods should be eliminated.
- Voluntary dedesignations of hedging relationships.
- Recognition of ineffectiveness for cash flow underhedges.
- Hedging components of nonfinancial items.
- Benchmark interest rates.
- Simplification of hedge documentation requirements.
- Presentation and disclosure matters.

P&U entities that use commodity and other hedging programs as part of their risk management strategies should consider closely following the Board’s activities related to hedge accounting.

Financial Instruments — Impairment

Background

In late 2012, the FASB issued a proposed ASU to obtain feedback on its current expected credit loss (CECL) model. Under the CECL model, an entity would recognize as an allowance its estimate of the contractual cash flows not expected to be collected. The FASB believes that the CECL model will result in more timely recognition of credit losses and will reduce complexity of U.S. GAAP by decreasing the number of different credit impairment models for debt instruments.11

Under the existing impairment models (often referred to as incurred loss models), an impairment allowance is recognized only after a loss event (e.g., default) has occurred or its occurrence is probable. In assessing whether to recognize an impairment allowance, an entity may only consider current conditions and past events; it may not consider forward-looking information.

CECL Model

Scope

The CECL model12 would apply to most13 debt instruments other than those measured at at FVTNI (lease receivables, reinsurance receivables that result from insurance transactions, financial guarantee contracts, and loan commitments). However, available-for-sale (AFS) debt securities would be excluded from the model’s scope and would continue to be assessed for impairment under ASC 320.

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11. Although impairment began as a joint FASB and IASB project, constituent feedback on the boards’ “dual-measurement” approach led the FASB to develop its own impairment model. The IASB, however, continued to develop the dual-measurement approach and issued final impairment guidance based on it as part of its July 2014 amendments to IFRS 9. For more information about the IASB’s impairment model, see Deloitte’s August 8, 2014, Heads Up.

12. The discussion of the CECL model reflects the FASB’s redeliberations to date, including tentative decisions made by the Board at its October 29, 2014, meeting.

13. The CECL model would not apply to the following debt instruments:
   - Loans made to participants by defined contribution employee benefit plans.
   - Policy loan receivables of an insurance entity.
   - Pledge receivables (promises to give) of a not-for-profit entity.
   - Loans and receivables between entities under common control.
Recognition of Expected Credit Losses

Unlike the incurred loss models in existing U.S. GAAP, the CECL model does not specify a threshold for the recognition of an impairment allowance. Rather, an entity would recognize an impairment allowance equal to the current estimate of expected credit losses (i.e., all contractual cash flows that the entity does not expect to collect) for financial assets as of the end of the reporting period. Credit impairment would be recognized as an allowance — or contra-asset — rather than as a direct write-down of the amortized cost basis of a financial asset. An entity would, however, write off the carrying amount of a financial asset when it is deemed uncollectible, which is consistent with existing U.S. GAAP.

Thinking It Through

Because the CECL model does not have a minimum threshold for recognition of impairment losses, entities will need to measure expected credit losses on assets that have a low risk of loss (e.g., investment-grade held-to-maturity debt securities). However, at its September 17, 2013, meeting, the FASB tentatively decided that an “entity would not be required to recognize a loss on a financial asset in which the risk of nonpayment is greater than zero [but] the amount of loss would be zero.” U.S. Treasury securities and certain highly rated debt securities may be assets the FASB contemplated when it tentatively decided to allow an entity to recognize zero credit losses on an asset, but the Board decided not to specify the exact types of assets. Nevertheless, the requirement to measure expected credit losses on financial assets whose risk of loss is low is likely to result in additional costs and complexity.

Measurement of Expected Credit Losses

An entity’s estimate of expected credit losses represents all contractual cash flows it does not expect to collect over the contractual life of the financial asset. When determining the contractual life of a financial asset, the entity would consider expected prepayments but would not be allowed to consider expected extensions unless it “reasonably expects” that it will execute a troubled debt restructuring.

The entity would consider all available relevant information in making the estimate, including information about past events, current conditions, and reasonable and supportable forecasts and their implications for expected credit losses. The entity is not required to forecast conditions over the contractual life of the asset. Rather, for the period beyond the period for which the entity can make reasonable and supportable forecasts, the entity would revert to an unadjusted historical credit loss experience.

The CECL model would not prescribe a unit of account (e.g., an individual asset or a group of financial assets) in the measurement of expected credit losses. However, an entity would be required to evaluate financial assets that are within the scope of the model on a collective (i.e., pool) basis when similar risk characteristics are shared. If a financial asset does not share similar risk characteristics with the entity’s other financial assets, the entity would evaluate the financial asset individually. If the financial asset is individually evaluated for expected credit losses, the entity would not be allowed to ignore available external information such as credit ratings and other credit loss statistics.

The FASB tentatively decided to permit the use of practical expedients in measuring expected credit losses for two types of financial assets:

- **Collateral-dependent financial assets** — In a manner consistent with existing U.S. GAAP, an entity would be allowed to measure its estimate of expected credit losses for collateral-dependent financial assets as the difference between the financial asset’s amortized cost and the collateral’s fair value.

- **Financial assets for which the borrower must continually adjust the amount of securing collateral (e.g., certain repurchase agreements and securities lending arrangements)** — The estimate of expected credit losses would be measured consistently with other financial assets within the scope of the CECL model but would be limited to the difference between the amortized cost basis of the asset and the collateral’s fair value (adjusted for selling costs, when applicable).
**Available-for-Sale Debt Securities**

Under the proposed ASU, the CECL model would have applied to AFS debt securities. However, in August 2014, the FASB tentatively decided that AFS debt securities would not be within the scope of the CECL model. Instead, the impairment of AFS debt securities would continue to be accounted for under ASC 320. However, the FASB tentatively decided to revise ASC 320 by:

- Requiring an entity to use an allowance approach (rather than permanently write down the security’s cost basis).
- Removing the requirement that an entity consider the length of time fair value has been less than amortized cost when assessing whether a security is other-than-temporarily impaired.
- Removing the requirement that an entity consider recoveries in fair value after the balance sheet date when assessing whether a credit loss exists.

**Thinking It Through**

The Board did not revise (1) step 1 of the existing other-than-temporary impairment model (i.e., an “investment is impaired if the fair value of the investment is less than its cost”) and (2) the requirement under ASC 320 that entities recognize the impairment amount only related to credit in net income and the noncredit impairment amount in OCI. However, the FASB did tentatively decide that entities would use an allowance approach when recognizing credit losses (as opposed to a permanent write down of the AFS security’s cost basis). As a result, in both of the following instances, an entity would reverse credit losses through current-period earnings on an AFS debt security:

1. If the fair value of the debt security exceeds its amortized cost in a period after a credit loss had been recognized through earnings (because fair value was less than amortized cost), the entity would reverse the entire credit loss previously recognized and recognize a corresponding adjustment to its allowance for credit losses.

2. If the fair value of the debt security does not exceed its amortized cost in a period after a credit loss had been recognized through earnings (because fair value was less than amortized cost) but the credit quality of the debt security improves in the current period, the entity would reverse the credit loss previously recognized only in an amount that would reflect the improved credit quality of the debt security.

The FASB’s tentative decisions to revise the impairment model in ASC 320 could result in earlier recognition of impairment.

**Disclosures**

Many of the disclosures required under the proposal are similar to those already required under U.S. GAAP as a result of ASU 2010-20. Accordingly, entities would be required to disclose information related to:

- Credit quality.
- Allowance for expected credit losses.
- Policy for determining write-offs.
- Past-due status.
- PCI assets.
- Collateralized financial assets.

14 Short-term trade receivables resulting from revenue transactions within the scope of ASC 605 are excluded from these disclosure requirements.
• Collateral-dependent financial assets.
• Policies for accounting for nonaccrual financial assets.

At a future meeting, the Board plans to discuss rollforward disclosures about an entity’s allowance and amortized cost balances and whether all of the tentative disclosure requirements should also apply to AFS debt securities.

**Next Steps**

The Board expects to discuss additional matters related to disclosures, transition, and effective date at a future meeting.

**Effects on Earnings per Unit of Master Limited Partnership Dropdown Transactions**

On October 30, 2014, the FASB issued a proposed ASU on MLP transactions in response to the EITF’s consensus-for-exposure on Issue 14-A. Under this proposal, upon the occurrence of a dropdown transaction occurring after initial formation of an MLP and accounted for as a reorganization of entities under common control, an MLP would allocate “the earnings (losses) of [the] transferred business before the date of the dropdown transaction . . . entirely to the general partner interest.” As a result, there would be no adjustment to historical earnings per unit reported for limited partner units.

Entities would apply the guidance in the proposed ASU retrospectively. The FASB plans to determine the proposal’s effective date after considering feedback from stakeholders.

For more information about the MLP proposal, see Deloitte’s September 2014 *EITF Snapshot.*

**FASB’s Disclosure Framework**

In July 2012, the FASB issued a DP as part of its project to develop a framework to make financial statement disclosures “more effective, coordinated, and less redundant.” The DP identifies aspects of the notes to the financial statements that need improvement and explores possible ways to improve them. See Deloitte’s July 17, 2012, *Heads Up* for additional information.

The FASB subsequently decided to distinguish between the “FASB’s decision process” and “entity’s decision process” for evaluating disclosure requirements.

**FASB’s Decision Process**

On March 4, 2014, the FASB released for public comment an ED of a proposed concepts statement that would add a new chapter to the Board’s conceptual framework for financial reporting. The ED proposes a decision process that the Board and FASB staff would use to determine what disclosures entities should be required to provide in the notes to the financial statements. The FASB’s objective in issuing the proposal is to improve disclosure effectiveness by ensuring that reporting entities clearly communicate the information that is most helpful to financial statement users. See Deloitte’s March 6, 2014, *Heads Up* for additional information.

**Summary of Comment-Letter Feedback**

Comments on the proposed concepts statement were due by July 14, 2014. The FASB received over 50 comment letters from various respondents, including preparers, professional and trade organizations, and accounting firms. Respondents generally expressed support for the development of a conceptual framework for use in evaluating disclosure requirements that would apply to existing and future standards.
However, many respondents were concerned that the ED’s “intentionally broad” proposed decision questions may result in excessive disclosures. Such respondents therefore suggested that the FASB use a filtering mechanism (e.g., based on cost and decision-usefulness) to further narrow disclosure requirements.

Respondents also suggested that the FASB clarify the difference between relevance and materiality and align the definition of materiality in the FASB’s concepts statement with that established by the Supreme Court.15 Subsequently, the FASB tentatively decided that the concepts statement would (1) state that materiality is a jurisdiction-based legal determination and (2) refer to the Supreme Court’s decision as an example.

Further, many respondents encouraged the Board to work with regulatory bodies, such as the SEC, to develop requirements that result in more effective, less redundant disclosures.

In their joint comment letter to the FASB, the EEI and AGA noted that “relevance” may significantly differ from “materiality” in various industries, including the P&U sector. For example, while gains and losses from derivative instruments used to manage risk may be quantitatively material to P&U entities’ income statements, the relevance of the information that must be disclosed about derivatives (ASC 815) and fair value measurements (ASC 820) may differ from that for other industries because of the nature of regulation. That is, for regulated P&U entities, derivative gains and losses are generally refundable to or recoverable from ratepayers and, therefore, the related fair value disclosures may not be as relevant since such gains and losses will ultimately be passed through to ratepayers and will not affect net income.

Next Steps

The FASB will continue redeliberating concerns raised in comment letters and will review feedback received as a result of its outreach activities, which included testing the entity’s decision process against various Codification topics (see below). A final concepts statement is expected to be issued after the outreach process is complete.

Entity’s Decision Process

Topic-Specific Disclosure Reviews

The FASB staff is currently analyzing ways to “further promote [entities’] appropriate use of discretion” in determining proper financial statement disclosures. This process will take into account “section-specific modifications” to the following Codification topics:

<table>
<thead>
<tr>
<th>ASC Topic</th>
<th>Status</th>
</tr>
</thead>
<tbody>
<tr>
<td>820 (fair value measurement)</td>
<td>Testing in progress. Results discussed with Board.</td>
</tr>
<tr>
<td>330 (inventory)</td>
<td>Not started.</td>
</tr>
<tr>
<td>715 (defined benefit plans)</td>
<td>Testing in progress. Results discussed with Board.</td>
</tr>
<tr>
<td>740 (income taxes)</td>
<td>Testing in progress. Partial results discussed with the Board.</td>
</tr>
</tbody>
</table>

A proposed ASU could be issued as a result of this process. No tentative decisions have been made on this matter to date.

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15 Paragraph QC11 in the third chapter of FASB Concepts Statement No. 8 states that “[i]nformation is material if omitting it or misstating it could influence decisions that users make on the basis of the financial information of a specific reporting entity.” Further, PCAOB Auditing Standard 11 explains that “[i]n interpreting the federal securities laws, the Supreme Court of the United States has held that a fact is material if there is a substantial likelihood that the . . . fact would have been viewed by the reasonable investor as having significantly altered the ‘total mix’ of information made available. As the Supreme Court has noted, determinations of materiality require ‘delicate assessments’ of the inferences a ‘reasonable shareholder’ would draw from a given set of facts and the significance of those inferences to him” (footnotes omitted).
Interim Reporting

The FASB deliberated modifications to the guidance on interim disclosure requirements. The Board tentatively decided that an update to an annual footnote disclosure is warranted as of an interim period if the update would alter the “total mix” of information available to investors. This is consistent with the guidance in SEC SAB 99, which is based on a Supreme Court ruling.16

During future redeliberations of interim reporting, the Board will continue reviewing comment-letter feedback on the ED.

FASB’s Simplification Initiative

Simplifying Income Statement Presentation by Eliminating the Concept of Extraordinary Items

In July 2014, as part of its simplification initiative, the FASB issued a proposed ASU that would remove from U.S. GAAP the concept of extraordinary items and therefore eliminate the requirement for entities to separately present such items in the income statement and disclose them in the footnotes. Extraordinary items are defined as those that (1) are unusual in nature and (2) occur infrequently. The proposed ASU retains the reporting and disclosure requirements for an event that demonstrates one of those characteristics but not both. Accordingly, financial statement users would continue to be informed about unusual or infrequent events after the concept of extraordinary items is eliminated.

The FASB believes that eliminating the concept would improve the efficiency of the financial reporting process since it would relieve entities from having to identify extraordinary items and comply with the associated presentation and disclosure requirements.

Comments on the proposal were due by September 30, 2014. If finalized, the new guidance would apply prospectively in annual periods beginning after December 15, 2015, and interim periods therein. Early adoption would be permitted.

Debt Issuance Costs

On October 14, 2014, the FASB issued a proposed ASU that would change the presentation of debt issuance costs in the financial statements. Under the proposal, an entity would be required to present such costs in the balance sheet as a direct deduction from the debt liability in a manner consistent with its accounting treatment of debt discounts. Amortization of the issuance costs would be reported as interest expense.

The proposed guidance would replace the guidance in ASC 835-30 that requires an entity to report debt issuance costs in the balance sheet as deferred charges (i.e., as an asset). It would also align U.S. GAAP on this topic with IFRSs, under which transaction costs that are directly attributable to the issuance of the liability are treated as an adjustment to the initial carrying amount of the financial liability.

Comments on the proposal were due by December 15, 2014. For more information about the proposed ASU, see Deloitte’s October 14, 2014, Heads Up.

Liabilities and Equity — Short-Term Improvements

In November 2014, the FASB voted to move part of its current research project on liabilities and equity to its active agenda. Specifically, the FASB decided to add a project addressing (1) practice issues related to ASC 815-40 and (2) targeted improvements to the organization of the related Codification topics, and (3) the indefinite deferral in ASC 480 for certain mandatorily redeemable noncontrolling interests issued by certain nonpublic entities. On a future date, the FASB will consider adding to its agenda a project related to convertible instruments.

To date, no technical decisions have been made in the project.

Private-Company Standard Setting

Definition of a Public Business Entity

In December 2013, the FASB issued ASU 2013-12, which defines the term “public business entity” (PBE). The definition establishes the scope of accounting alternatives developed by the Private Company Council (PCC). Specifically, entities that do not qualify as PBEs are generally eligible for private-company accounting alternatives. In addition, the FASB will incorporate the term PBE into future standard setting. Under the recently issued revenue standard, for example, an entity would refer to the definition of a PBE to determine whether it qualifies for effective date and disclosure relief. Therefore, even if an entity has no plans to elect a private-company accounting alternative, it should consider whether it meets the definition of a PBE when evaluating its eligibility for relief under future standards. An entity would apply the definition of a PBE in connection with its adoption of the first ASU that uses the term.

The ASU defines a PBE as a business entity that meets any one of the following criteria:

a. It is required by the U.S. Securities and Exchange Commission (SEC) to file or furnish financial statements, or does file or furnish financial statements (including voluntary filers), with the SEC (including other entities whose financial statements or financial information are required to be or are included in a filing).

b. It is required by the Securities Exchange Act of 1934 (the Act), as amended, or rules or regulations promulgated under the Act, to file or furnish financial statements with a regulatory agency other than the SEC.

c. It is required to file or furnish financial statements with a foreign or domestic regulatory agency in preparation for the sale of or for purposes of issuing securities that are not subject to contractual restrictions on transfer.

d. It has issued, or is a conduit bond obligor for, securities that are traded, listed, or quoted on an exchange or an over-the-counter market.

e. It has one or more securities that are not subject to contractual restrictions on transfer, and it is required by law, contract, or regulation to prepare U.S. GAAP financial statements (including footnotes) and make them publicly available on a periodic basis (for example, interim or annual periods). An entity must meet both of these conditions to meet this criterion.

Although these criteria are largely drawn from similar definitions under other standards (e.g., the definition of “public entity” in ASC 280), some are new. For example, criterion (a) is not in certain definitions and criterion (e) is not in any. Further, an entity would meet criterion (a) if its financial statements are included in another entity’s SEC filing (e.g., as a significant investee or an acquiree of an SEC registrant). Thus, in certain instances, an entity that would have been considered nonpublic under previous guidance will now qualify as a PBE. Conversely, because a subsidiary of a public company is not automatically a PBE under the ASU, there may be instances in which an entity that would have been considered public will not qualify as a PBE for stand-alone financial statement purposes.

An entity that determines it is not a PBE and that it can therefore elect the private-company accounting alternatives should remain cognizant of the following:

- **The mandates, if any, of its financial statement users** — The ASU’s Basis for Conclusions acknowledges that “decisions about whether an entity may apply permitted differences within U.S. GAAP ultimately may be determined by regulators (for example, the SEC and financial institution regulators), lenders and other creditors, or other financial statement users that may not accept financial statements that reflect accounting or reporting alternatives for private companies.” Therefore, entities should seek to understand the views of their regulators and other users about the acceptability of the accounting alternatives before making an election.

- **The absence of transition guidance** — The ASU does not provide guidance on situations in which an entity subsequently meets the definition of a PBE as a result of changes in circumstances. Entities should assume that they would be required to eliminate any private-company accounting alternatives from their historical financial statements if they later meet the definition of a PBE (e.g., in connection with an IPO). Therefore, from a practical
perspective, entities considering electing a private-company accounting alternative should consider the likelihood that they may later meet the definition of a PBE — and the potential effort associated with unwinding the accounting alternative — before making an election.

For more information about ASU 2013-12, see Deloitte’s January 27, 2014, Heads Up.

An entity may need to carefully examine the circumstances related to both its financial statement requirements and any restrictions on the transfer of its securities in determining whether it satisfies any of the PBE criteria. Many P&U entities will meet the definition of a PBE. Further, regardless of their eligibility under U.S. GAAP to elect private-company alternatives, entities may receive input from their regulators about whether electing such alternatives is acceptable.

### Accounting Alternatives for Private Companies

The PCC was established in 2012 to improve the accounting standard-setting process for private companies. During 2014, the PCC finalized alternative accounting guidance on the following (early adoption of each ASU is permitted):

- **Goodwill** — ASU 2014-02 allows private companies to use a simplified approach to account for goodwill after an acquisition. Under this alternative, an entity would (1) amortize goodwill on a straight-line basis, generally over 10 years; (2) test goodwill for impairment only when a triggering event occurs; and (3) make an accounting policy election to test for impairment at either the entity level or the reporting-unit level. In addition, the ASU eliminates “step 2” of the goodwill impairment test; as a result, goodwill impairment is measured as the excess of the entity’s (or reporting unit’s) carrying amount over its fair value. The accounting alternative, if elected, should be applied prospectively to goodwill existing as of the beginning of the period of adoption and new goodwill recognized in annual periods beginning after December 15, 2014, and interim periods within annual periods beginning after December 15, 2015. Early adoption is permitted, including application to any period for which the entity’s annual or interim financial statements have not yet been made available for issuance. See Deloitte’s January 27, 2014, Heads Up for more information.

- **Hedge accounting** — Under ASU 2014-03, private companies can apply a simplified method to account for interest rate swaps used to hedge variable-rate debt. An entity that elects to apply this method to a qualifying hedging relationship would continue to account for the interest rate swap and the variable-rate debt separately on the face of the balance sheet. However, such an entity would be able to assume no ineffectiveness in the hedging relationship and thus would essentially be able to achieve the same income statement effects as if it had issued fixed-rate debt. An entity that applies the simplified hedge accounting approach also may elect to measure the related swap at its settlement value rather than fair value. P&U entities would generally be eligible to elect this accounting alternative. The simplified hedge accounting approach is effective for annual periods beginning after December 15, 2014, and interim periods within annual periods beginning after December 15, 2015; early adoption is permitted. Entities would adopt the ASU under either a full retrospective or a modified retrospective method. See Deloitte’s January 27, 2014, Heads Up for more information.

- **Consolidation** — ASU 2014-07 gives private companies an exemption from having to apply the VIE consolidation guidance to a related-party lessor when the entity and the lessor are under common control. The entity must evaluate additional criteria about the relationship between the lessee and lessor before applying this exemption. If it applies the ASU, the entity may no longer be required to consolidate a related-party lessor entity. The alternative is effective for annual periods beginning after December 15, 2014, and interim periods within annual periods beginning after December 15, 2015. Early adoption is permitted, including application to any period for which the entity’s annual or interim financial statements have not yet been made available for issuance. The ASU should be applied retrospectively. See Deloitte’s March 21, 2014, journal entry for more information.

- **Intangible assets** — ASU 2014-18 companies with an exemption from having to recognize or otherwise consider the fair value of certain intangible assets in connection with in-scope transactions (i.e., business combinations, equity method investments and fresh-start reporting). Specifically, an entity is not required to recognize intangible assets for noncompete agreements and certain customer-related intangible assets. Because the amounts associated
with these items are subsumed into goodwill, an entity that elects this accounting alternative is also required to elect the goodwill accounting alternative, resulting in the amortization of goodwill. An entity that elects to adopt the accounting alternative should apply the guidance prospectively to the first eligible transaction within the scope of the ASU that occurs in an annual period beginning after December 15, 2015 (early adoption is permitted) and to all transactions thereafter.

Throughout 2014, the PCC discussed aspects of financial reporting that are complex and costly for private companies. The accounting for stock-based compensation was a significant focus of these discussions. In a recent meeting, the PCC and FASB board members agreed that the PCC would incorporate its views on this topic into the separate stock-based compensation project that the FASB is undertaking as part of its simplification initiative.
Section 7
Introducing a New Revenue Model
Background

On May 28, 2014, the FASB and IASB issued their final standard on revenue from contracts with customers. The standard, issued as ASU 2014-09 by the FASB and as IFRS 15 by the IASB, outlines a single comprehensive model for entities to use in accounting for revenue arising from contracts with customers and supersedes most current revenue recognition guidance, including industry-specific guidance.1

The goals of the ASU are to clarify and converge the revenue recognition principles under U.S. GAAP and IFRSs while (1) streamlining, and removing inconsistencies from, revenue recognition requirements; (2) providing “a more robust framework for addressing revenue issues”; (3) making revenue recognition practices more comparable; and (4) increasing the usefulness of disclosures. The ASU states that the core principle for revenue recognition is that an “entity shall recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services.” The ASU indicates that an entity should perform the following five steps in recognizing revenue:

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

As a result of the ASU, entities will need to comprehensively reassess their current revenue accounting and determine whether changes are necessary. Entities are also required to provide significantly expanded disclosures about revenue recognition, including both quantitative and qualitative information about (1) the amount, timing, and uncertainty of revenue (and related cash flows) from contracts with customers; (2) the judgment, and changes in judgment, used in applying the revenue model; and (3) the assets recognized from costs to obtain or fulfill a contract with a customer.

Key Accounting Issues

Although the ASU may not significantly change how P&U entities typically recognize revenue, a few of the ASU’s requirements may be inconsistent with current practice. Discussed below are some key provisions of the ASU that may affect P&U entities as well as how the guidance might be considered in some typical transactions.

To help P&U entities implement the ASU, the FASB and IASB have created a joint transition resource group (TRG) and the AICPA has assembled a P&U industry task force.2 In addition, the AICPA is currently developing an accounting guide on revenue recognition. See Deloitte’s July 2014 and October 2014 TRG Snapshot publications for information about the topics discussed to date by the TRG.

Tariff Sales of a Regulated Utility

While ASU 2014-09 supersedes much of the industry-specific revenue guidance in current U.S. GAAP, it retains the guidance in ASC 980-605 on rate-regulated operations that have alternative revenue programs. P&U entities within the scope of ASC 980-605-15 will continue to recognize additional revenues allowable for Type A and Type B alternative revenue programs if those programs meet the criteria in ASC 980-605-25-4. However, in the statement of comprehensive income,

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1 The SEC has indicated that it plans to review and update the revenue recognition guidance in SEC Staff Accounting Bulletin (SAB) Topic 13, “Revenue Recognition,” in light of the issuance of the ASU. The extent to which the ASU’s guidance will affect a public entity will depend on whether the SEC removes or amends the guidance in SAB Topic 13 to be consistent with the new revenue standard.

2 Deloitte is represented on both the TRG and the AICPA task force.
revenues arising from such programs will be presented separately from revenues arising from contracts with customers that are within the scope of the ASU.

One of the issues that we expect the P&U industry task force to review is whether sales to tariff-based customers are within the scope of the ASU. If such sales are deemed to be within the ASU’s scope, it will be necessary to determine the term of the contractual relationship between the utility and each customer as well as any rights or obligations either party has under the contract.

**Blend-and-Extend Contract Modifications**

**Contract Modifications**

P&U entities should consider how they are affected by the ASU’s guidance on accounting for “approved” modifications to contracts with customers. The approval of a contract modification can be in writing, by oral agreement, or implied by customary business practices, and a contract modification is considered approved when it creates new, or changes existing, enforceable rights or obligations. A contract modification must be accounted for as a separate contract when (1) it results in a change in contract scope because of additional promised “distinct” goods or services (see Distinct Performance Obligations below) and (2) the additional consideration reflects the entity’s stand-alone selling price for those additional promised goods or services (including any appropriate adjustments to reflect the circumstances of the contract). That is, the entity would continue to account for the existing contract as if it was not modified and account for the additional goods or services provided in the modification as a “new” contract.

If a contract modification is not considered a separate contract (i.e., it does not meet the criteria above), an entity should evaluate the remaining goods and services in the modified contract and determine whether to account for the modification prospectively (if the remaining goods and services are distinct from those already transferred) or retrospectively in accordance with the ASU. If the remaining goods and services are distinct from those already transferred, the modification is accounted for prospectively, the transaction price is updated (i.e., it now includes both the remaining consideration from the original contract and the additional consideration in the modification), and the updated transaction price is allocated to the remaining goods and services to be transferred. In contrast, if the goods or services are not distinct and are part of a single performance obligation, the modification is treated retrospectively and the amount of revenue recognized to date is adjusted to reflect the new modified contract (e.g., the measure of progress is adjusted to account for the new expectation of performance completed), resulting in a cumulative-effect catch-up adjustment.

**Blend-and-Extend Contract Modifications**

B&E contract modifications are common in the P&U industry. In a typical B&E modification, the supplier and customer may renegotiate the contract to allow the customer to take advantage of lower commodity pricing while the supplier increases its future delivery portfolio. Under such circumstances, the customer and supplier agree to “blend” the remaining, original, higher contract rate with the lower, extension-period rate for the remainder of the original contract term plus an extended term. The supplier therefore defers the cash realization of some of the contract fair value that it would have received under the original contract terms until the extension period, at which time it will receive an amount that is greater than the current market price for those periods as of the date of the modification.
Potential Impact of New Revenue Model

P&U entities should carefully evaluate the facts and circumstances related to a B&E contract modification to determine whether it should be accounted for as a new contract (which may include a significant financing component) or as a prospective contract modification. A B&E contract modification is treated as a new contract when distinct goods or services are added to the contract and the additional consideration reflects the stand-alone selling price of those additional goods or services. In such cases, the payment terms may need to be reevaluated because the blending of the prices may create a significant financing component under the view that some of the consideration for the future goods or services is paid early as a result of the “blended” price agreed to by the parties. In contrast, when the additional distinct goods are not included at the stand-alone selling price in the contract modification, the modification will be treated prospectively (since the remaining and additional deliveries would be distinct from the goods delivered as of the modification date) and the new blended price will be allocated to the remaining goods to be provided to the customer (including the undelivered goods in the original contract and the newly added goods).

Commodity Exchange Arrangements

Scope Considerations

Commodity exchange arrangements are common in the P&U industry. In these arrangements, an entity agrees to sell a certain quantity and grade of a commodity to a counterparty at a specified location and simultaneously agrees to buy a specific quantity and grade of a similar commodity from that same counterparty at another location. In effect, specified inventories of the two parties are exchanged (e.g., in-ground natural gas inventories are exchanged at different storage locations). Entities usually enter into such arrangements to avoid ancillary costs (e.g., transportation costs).

Companies may need to determine whether these types of arrangements are outside the scope of the new revenue recognition model and are instead accounted for under ASC 845. Generally, the purpose of exchange arrangements is to allow the parties to meet the needs of the market; therefore, the parties in such arrangements are not considered to be the end-user purchasers of the product if they are in the same line of business. Although a counterparty in a commodity exchange arrangement may meet the ASU’s definition of a “customer,” nonmonetary exchanges between two parties in the “same line of business” are outside the new standard’s scope. Therefore, the new revenue model is not expected to have a significant impact on commodity exchange arrangements.

In certain arrangements, a marketer or other P&U entity may agree to sell wet gas to a gas processor and simultaneously buy back, as separate products, dry gas, condensates, natural gas liquids, etc. Such agreements are generally considered tolling arrangements, and P&U entities should carefully assess these arrangements to determine whether they are within the scope of the new revenue guidance or constitute a lease or receipt of a processing service that is accounted for under other U.S. GAAP. Similar considerations would also apply to gas-to-power tolls. P&U entities should be aware that while gas-processing and other tolling arrangements may be structured similarly to commodity exchange arrangements, the applicability of the ASU to the two types of arrangements may differ.
Distinct Performance Obligations

Identifying the Performance Obligations in the Contract

The ASU provides guidance on evaluating the promised “goods or services” in a contract to determine each performance obligation (i.e., the unit of account). A performance obligation is each promise to transfer either of the following to a customer:

- “A good or service (or a bundle of goods or services) that is distinct.”
- “A series of distinct goods or services that are substantially the same and that have the same pattern of transfer to the customer.”

Under the ASU, a series of distinct goods or services has the same pattern of transfer if both of the following criteria are met: (1) each distinct good or service in the series meets the criteria for recognition over time and (2) the same measure of progress is used to depict performance in the contract. Therefore, a simple forward sale of electricity, natural gas, etc., for which delivery of the same product is required over time would generally be treated as a single performance obligation satisfied continuously throughout the contract term. In this case, a P&U entity would determine an appropriate method for measuring progress toward complete satisfaction of the single performance obligation and would recognize the transaction price as revenue as progress is made.

Variable Pricing

Determining the Transaction Price

The ASU requires that variable consideration be included in the transaction price under certain circumstances. An estimate of variable consideration is only included in the transaction price to the extent that it is probable that subsequent changes in the estimate would not result in a “significant reversal” of revenue. This concept is commonly referred to as the “constraint.” The ASU requires entities to perform a qualitative assessment that takes into account the likelihood and magnitude of a potential revenue reversal and provides factors that could indicate that an estimate of variable consideration is subject to significant reversal (e.g., susceptibility to factors outside the entity’s influence, long period before uncertainty is resolved, limited experience with similar types of contracts, practices of providing concessions, or a broad range of possible consideration amounts). This estimate would be updated in each reporting period to reflect changes in facts and circumstances.

The use of variable consideration (e.g., index or formula-based pricing), as well as uncertainty regarding delivery quantity, may present challenges related to estimating and allocating the transaction price and applying the ASU’s constraint guidance. For example, a P&U entity may have a multiyear contract to sell a fixed quantity of electricity each hour at a price derived from a formula. When the transaction price includes a variable amount, an entity must estimate the variable consideration by using either an “expected value” (probability-weighted) approach or a “most likely amount” approach, whichever is more predictive of the amount to which the entity expects to be entitled.

3 Although the ASU does not define goods or services, it includes several examples, such as goods produced (purchased) for sale (resale), granting a license, and performing contractually agreed-upon tasks.

4 “Probable” in this context has the same meaning as in ASC 450-20: “the event or events are likely to occur.” In IFRS 15, the IASB uses the term “highly probable,” which has the same meaning as the FASB’s “probable.”
A contract may include various types of consideration. In some cases, an entity may need to use significant judgment in estimating certain variable amounts (e.g., amounts based on wind generation). In other instances, amounts may vary but are more easily estimated, such as potential minimum fees or charges that are, in substance, fixed (e.g., a capacity charge). When evaluating the constraint in such cases, an entity would determine the significance of the potential revenue reversal by comparing the potential reversal with the total consideration (including both fixed and variable consideration). The larger the fixed consideration (e.g., guaranteed minimum or capacity charges) is in proportion to the total consideration, the greater the likelihood that amounts of variable consideration would not create the potential for a “significant” reversal (i.e., the estimate would not be “constrained” and would therefore be included in the transaction price).

### Power Purchase Agreements

PPAs typically give the power purchaser the right, over the term of the contract, to buy from the independent power producer an amount of energy in exchange for a fixed price, a variable price, or a combination of fixed and variable pricing.

#### Identify the Contract With a Customer

Two P&U entities will often collaborate to develop a new generator, plant, or asset; in such contracts, one of the two parties will agree to off-take part or all of the power produced. For example, an industrial manufacturer or utility that wants to obtain power and green attributes may collaborate with a supplier (that will construct, own, and retain tax benefits from the generating asset) to design and develop a solar or wind farm. The parties in such collaborative arrangements will need to consider all facts and circumstances to determine whether a supplier/customer relationship exists.

#### Identifying the Performance Obligation(s) in the Contract

A PPA is a good example of an arrangement in which a series of distinct goods is accounted for as a single performance obligation. That is, when PPAs do not qualify as leases or derivatives, P&U entities may conclude under the ASU that a PPA represents a single performance obligation satisfied over time because:

- The product is substantially the same and will be transferred consecutively in the series (see ASC 606-10-25-14(b)) — for example, in consecutive hourly deliveries of electricity over multiple years.
- The customer will simultaneously receive and consume the benefits of each distinct delivery of electricity (i.e., the delivery of electricity meets the criterion in ASC 606-10-25-27(a) and, as a result, the series meets the criterion in ASC 606-10-25-15(a)).
- The same measure of progress for each distinct delivery of electricity (e.g., a unit-based measure) would be used, thereby satisfying the criterion in ASC 606-10-25-15(b).

Note that an entity may need to consider additional factors when electricity is bundled with other products and services under a PPA. See Bundled Arrangements below for more information.

#### Determining the Transaction Price

The amount and timing of contract pricing in a PPA can vary as a result of a number of commercial terms and contract provisions. PPAs, including those related to renewable energy sources such as wind, often contain explicit variable pricing provisions. Such PPAs might also include payment amounts related to a minimum availability requirement — for example, to ensure that the supplier’s investment in the generation asset is recovered. This minimum availability payment may be relatively large compared with variable payments. Although the minimum availability payment may depend on the entity’s ability to make available the renewable energy source throughout the PPA, such availability may be largely within the entity’s control.

The ASU states that when determining the transaction price, an entity should “assume that the goods or services will be transferred to the customer as promised in accordance with the existing contract and that the contract will not
be cancelled, renewed, or modified.” Because the entity can anticipate its own performance when determining the transaction price, the evaluation of the constraint (i.e., whether a significant revenue reversal may occur) may be eased as the magnitude of any potential subsequent reversal is mitigated by the fixed consideration (i.e., the minimum availability payment). See Variable Pricing above for additional discussion.

Recognizing Revenue When (or as) Performance Obligations Are Satisfied

A supplier recognizes revenue in a PPA that is determined to be a performance obligation satisfied over time by measuring progress toward satisfying the performance obligation in a manner that best depicts the transfer of goods or services to the customer (see Distinct Performance Obligations above for more details). Certain types of pricing provisions in a PPA may warrant a careful examination of the measure of progress to be used. Possible approaches for measuring progress may include (1) an output measure of progress (e.g., based on MWh delivered), (2) the invoicing method as an output measure of progress (i.e., as a practical expedient), or (3) an input measure of progress (e.g., costs incurred). We expect the P&U industry task force to address this topic and make implementation recommendations. It is generally expected that deliveries under strip-price contracts will be recognized at the contract price (i.e., will not give rise to embedded financing elements). P&U entities will need to consider this approach when assessing contracts with other pricing conventions (e.g., step-price arrangements).

Take-or-Pay Arrangements

In a take-or-pay arrangement, a customer pays a specified price to a supplier for a minimum volume of product or level of services. Such an arrangement is referred to as “take-or-pay” because the customer must pay for the product or services regardless of whether it actually takes delivery. Power, natural gas, and other energy commodity off-take contracts, as well as certain service arrangements (e.g., those related to natural gas storage or transportation), may be structured as take-or-pay.

Identifying the Performance Obligation(s) in the Contract

As in a PPA, in a take-or-pay arrangement, the supplier would generally conclude under the ASU that it has entered into a contract with a customer to deliver a series of distinct, but substantially the same, goods delivered consecutively over time (see discussion above in Distinct Performance Obligations). The supplier should account for that series of distinct goods as a single performance obligation — and as a single unit of account — because:

• The customer simultaneously receives and consumes the benefits of each distinct delivery of electricity or other commodity (i.e., the delivery of electricity meets the criterion in ASC 606-10-25-27(a) and, as a result, the series meets the criterion in ASC 606-10-25-15(a)).

• The same measure of progress for each distinct delivery of electricity or other commodity (e.g., a unit-based measure) would be used, thereby satisfying the criterion in ASC 606-10-25-15(b).

Recognizing Revenue When (or as) Performance Obligations Are Satisfied

Because the performance obligation in a take-or-pay arrangement is satisfied over time, the supplier recognizes revenue by measuring progress toward satisfying the performance obligation in a manner that best depicts the transfer of goods or services to the customer. The best depiction of the supplier’s performance in transferring control of the goods and satisfying its performance obligation may differ depending on the terms of the take-or-pay arrangement:

• Consider a vanilla take-or-pay arrangement for monthly deliveries of natural gas whereby the customer pays irrespective of whether it takes delivery and does not have the ability to make up deliveries not taken. In this case,
it may be appropriate to use an output measure of progress based on time to recognize revenue because the supplier could be satisfying its performance obligation as each month passes.

- In a take-or-pay arrangement for monthly deliveries of natural gas whereby the customer can make up deliveries not taken later in the contract tenor, an output measure of progress based on units delivered may be appropriate. In this case, the supplier should recognize revenue for volumes of natural gas actually delivered to the customer each month and recognize a contract liability for volumes not taken, since the supplier’s performance obligation associated with those volumes is unsatisfied despite receipt of customer payment.

**Bundled Arrangements**

Electricity is often sold in conjunction with other energy-related products and services, including capacity, various ancillary services such as voltage control, and RECs. Companies regularly enter into transactions in which such items as energy, RECs, and capacity are bundled together in a single contract, often with one transaction price.

**Scope Considerations**

ASU 2014-09 explicitly states that if other Codification topics address how to separate and account for the different products and services in a contract with a customer, entities should look to those topics first. Specifically, ASC 606-10-15-4 states:

> A contract with a customer may be partially within the scope of this Topic and partially within the scope of other Topics. . . .

a. If the other Topics specify how to separate and/or initially measure one or more parts of the contract, then an entity shall first apply the separation and/or measurement guidance in those Topics . . . .

b. If the other Topics do not specify how to separate and/or initially measure one or more parts of the contract, then the entity shall apply the guidance in this Topic to separate and/or initially measure the part (or parts) of the contract.

P&U entities should carefully consider their contracts with customers for multiple products and services and assess whether (1) products or services separated in accordance with the guidance in other Codification topics should be accounted for under ASU 2014-09 and (2) an entity should apply ASU 2014-09’s guidance on distinct performance obligations when separating multiple products and services in contracts with customers.

**Identifying the Performance Obligation in the Contract**

As discussed above, P&U entities that sell, for example, RECs together with the related energy may need to assess whether the promise to deliver RECs represents a performance obligation that is “distinct” from the promise to deliver electricity (see discussion above in **Distinct Performance Obligations**). Under the ASU, a performance obligation is distinct if it meets both of the following criteria in ASC 606-10-25-19:

- The good or service in the performance obligation is capable of being distinct (i.e., the customer can benefit from the good or service on its own or with readily available resources).
- The good or service is distinct in the context of the contract (i.e., it is separately identifiable from other goods or services in the contract).

If an entity concludes that the promise to deliver the RECs, for example, meets both criteria, that promise will be considered a distinct performance obligation. The transaction consideration will be proportionally allocated to each performance obligation (e.g., to the electricity and RECs).
Recognizing Revenue When (or as) Performance Obligations Are Satisfied

After determining which goods or services in the bundled arrangement result in distinct performance obligations, a P&U entity must assess when control of the good or service within each performance obligation is transferred (i.e., over time or at a point in time) to determine when revenue will be recognized.

Control of a good or service (and therefore satisfaction of the related performance obligation) is transferred over time when at least one of the following criteria is met:

- “The customer simultaneously receives and consumes the benefits provided by the entity’s performance as the entity performs."
- “The entity’s performance creates or enhances an asset . . . that the customer controls as the asset is created or enhanced."
- “The entity’s performance does not create an asset with an alternative use to the entity . . . and the entity has an enforceable right to payment for performance completed to date."

If a performance obligation is not satisfied over time, it is deemed satisfied at a point in time. Under the ASU, entities would consider the following indicators in evaluating the point at which control of an asset has been transferred to a customer:

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

The recognition of revenue is determined separately for each distinct performance obligation within a bundled arrangement. Therefore, there may be delays in the recognition of revenue attributable to other products and services that are sold with the related energy.

In the REC example above (in which the RECs are a distinct performance obligation), for instance, the P&U entity would need to appropriately consider the manner that best depicts the transfer of the RECs to the off-taker as it determines when it has satisfied the distinct performance obligation to deliver the certificates. If the title of the certificate is not transferred when the energy is sold (e.g., as a result of certification lag), control of the certificates may not have been transferred to the off-taker. Thus, revenue from the RECs may not be recognized at the same time as it is for the energy.

Some entities have historically concluded that, while the transfer of the title to RECs may lag behind the selling of the energy, certification is perfunctory after generation of the energy is complete and the patterns of revenue recognition for RECs should therefore match those for the energy. Entities may need to revisit this practice when adopting the ASU.

Sales of Power-Generating Property, Plant, and Equipment

P&U entities often enter into arrangements that include the full or partial sale of power-generating PP&E (e.g., transactions involving the sale of all or a part of power plants, solar farms, and wind farms). Under current GAAP, depending on the nature of the transaction, an entity might conclude that the transaction is the sale of a business and account for it under ASC 810-10 or, alternatively, conclude that it is the sale of real estate and account for it under ASC 360-20.
In-Substance Nonfinancial Assets

Currently, an entity accounts for real estate sales that take the form of an ownership interest in the entity by applying both the real estate sales guidance in ASC 360 and the guidance in ASC 810 (rather than only the deconsolidation guidance in ASC 810) if the sale involves an investment that is considered in-substance real estate (e.g., an equity interest in an entity whose sole asset is a single property). In addition, entities evaluate the disposal of equipment attached to real estate assets in accordance with ASC 360 if the equipment is considered integral equipment.

The ASU expands the concept of in-substance real estate to include all in-substance nonfinancial assets. Accordingly, an entity applies only the deconsolidation guidance in ASC 810 when the transfer or sale of a subsidiary or business is not considered the sale of in-substance nonfinancial assets. While the ASU does not define in-substance nonfinancial assets, a transaction that historically has been outside the scope of ASC 360 may be accounted for under the ASU’s guidance (rather than only ASC 810) if the entity substantially comprises nonfinancial assets (including real estate).

The ASU’s consequential amendments eliminate the guidance in ASC 360-20 on sales of real estate. Entities will therefore need to apply the new guidance in ASC 606 on sales or transfers of nonfinancial assets (including real estate).

Accounting for Partial Sales

Under ASC 360, a sale is considered a partial sale if the seller retains an equity interest in the property (or the buyer). Profit (the difference between the sales price and the proportionate cost of the partial interest sold) is recognized only if the buyer is independent of the seller (i.e., not a consolidated subsidiary of the seller) and if certain other requirements are met. The ASU does not carry forward the current guidance in ASC 360 on partial sales and does not provide guidance on the appropriate unit of account for performing this evaluation. Specifically, the ASU does not indicate whether the evaluation should focus on the transfer of control of the interest in the entity (as it would for the sale of an undivided interest) or on the transfer of control of the underlying asset held by the entity. The focus of the evaluation could significantly affect an entity’s determination of whether control has been transferred.

The FASB is currently evaluating its guidance on partial sales or transfers of nonfinancial assets as part of its project to clarify the definition of a business. However, if the FASB does not complete this project by the time the ASU becomes effective, diversity in practice may evolve since entities may apply different approaches to determine how to account for partial sales of nonfinancial assets in accordance with the ASU.

Disclosures

The ASU requires significantly more disclosures, including additional quantitative and qualitative information that enables “users of financial statements to understand the nature, amount, timing, and uncertainty of revenue and cash flows arising from contracts with customers.” The ASU’s disclosure requirements include:

- Presentation or disclosure of revenue and any impairment losses recognized separately from other sources of revenue or impairment losses from other contracts.
- A disaggregation of revenue to “depict how the nature, amount, timing, and uncertainty of revenue and cash flows are affected by economic factors” (the ASU also provides implementation guidance).
- Information about contract assets and liabilities (including changes in those balances) and the amount of revenue recognized in the current period that was previously recognized as a contract liability and the amount of revenue recognized in the current period that is related to performance obligations satisfied in prior periods.
- Information about performance obligations (e.g., types of goods or services, significant payment terms, typical timing of satisfying obligations, and other provisions).
• Information about an entity’s transaction price allocated to the remaining performance obligations, including (in certain circumstances) the “aggregate amount of the transaction price allocated to the performance obligations that are unsatisfied (or partially unsatisfied)” and when the entity expects to recognize that amount as revenue.

• A description of the significant judgments, and changes in those judgments, that affect the amount and timing of revenue recognition (including information about the timing of satisfaction of performance obligations, the determination of the transaction price, and the allocation of the transaction price to performance obligations).

• Information about an entity’s accounting for costs to obtain or fulfill a contract (including account balances and amortization methods).

• Information about the policy decisions (i.e., whether the entity used the practical expedients for significant financing components and contract costs allowed by the ASU).

The ASU requires entities, on an interim basis, to disclose information required under ASC 270 as well as to provide disclosures similar to the annual disclosures (described above) about (1) the disaggregation of revenue, (2) contract asset and liability balances and significant changes in those balances since the previous period-end, and (3) information about the remaining performance obligations.

Effective Date and Transition

The ASU is effective for annual reporting periods (including interim reporting periods within those periods) beginning after December 15, 2016, for public entities. Early application is not permitted (however, early adoption is optional for entities reporting under IFRSs).

The effective date for nonpublic entities is annual reporting periods beginning after December 15, 2017, and interim reporting periods within annual reporting periods beginning after December 15, 2018. Nonpublic entities may also elect to apply the ASU as of any of the following:

• The same effective date as that for public entities (annual reporting periods beginning after December 15, 2016, including interim periods).

• Annual periods beginning after December 15, 2016 (excluding interim reporting periods).

• Annual periods beginning after December 15, 2017 (including interim reporting periods).

During the October 2014 TRG meeting, FASB Vice Chairman James Kroeker announced that the FASB and its staff plan to conduct further outreach with both public and private companies over the next several months to gauge their progress with implementing the guidance in ASU 2014-09. Mr. Kroeker emphasized that the Board is considering whether to defer the effective date of the new revenue guidance and noted that a decision will be made no later than the second quarter of 2015.

Entities have the option of using either a full retrospective or a modified approach to adopt the guidance in the ASU.

• Full retrospective application — Retrospective application would take into account the requirements in ASC 250 (with certain practical expedients). Under this approach, entities would need to reevaluate their contracts from inception to determine the income recognition pattern that best depicts the transfer of goods and services. Further, for comparative financial statement purposes, public entities with a calendar year-end would be required to present income under the new revenue model beginning on January 1, 2015.

The SEC staff in the Division of Corporation Finance (the “Division”) has indicated that it would not object if the basis that a registrant uses to reflect its adoption of the new revenue standard in selected financial data (as required by Regulation S-K, Item 301) is the same as the basis that it uses to adopt the new revenue standard in its financial statements. If a registrant presents less than five years on the basis of the new revenue standard, it
would need to disclose the method it used and that the prior years in the selected financial data disclosure are not comparable. See Deloitte’s September 12, 2014, journal entry for more information.5

• **Modified retrospective application** — Under the modified approach, an entity recognizes “the cumulative effect of initially applying [the ASU] as an adjustment to the opening balance of retained earnings . . . of the annual reporting period that includes the date of initial application” (revenue in periods presented in the financial statements before that date is reported under guidance in effect before the change). Under the modified approach, the guidance in the ASU is only applied to existing contracts (those for which the entity has remaining performance obligations) as of, and new contracts after, the date of initial application. The ASU is not applied to contracts that were completed before the effective date (i.e., an entity has no remaining performance obligations to fulfill). Entities that elect the modified approach must disclose an explanation of the impact of adopting the ASU, including the financial statement line items and respective amounts directly affected by the standard’s application. The following chart illustrates the application of the ASU and legacy GAAP under the modified approach for a public company with a calendar year-end:

<table>
<thead>
<tr>
<th>Initial Application Year</th>
<th>2017</th>
<th>2016</th>
<th>2015</th>
</tr>
</thead>
<tbody>
<tr>
<td>New contracts</td>
<td>New ASU</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Existing contracts</td>
<td>New ASU + cumulative catch-up</td>
<td>Legacy GAAP</td>
<td>Legacy GAAP</td>
</tr>
<tr>
<td>Completed contracts</td>
<td>Legacy GAAP</td>
<td>Legacy GAAP</td>
<td>Legacy GAAP</td>
</tr>
</tbody>
</table>

The modified transition approach provides entities relief from having to restate and present comparable prior-year financial statement information; however, entities will still need to evaluate existing contracts as of the date of initial adoption under the ASU to determine whether a cumulative adjustment is necessary. Therefore, entities may want to begin considering the typical nature and duration of their contracts to understand the impact of applying the ASU and determine the transition approach that is practical to apply and most beneficial to financial statement users.

See Deloitte’s August 2014 *Power & Utilities Spotlight* for additional information on potential implementation challenges for P&U entities.

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5 At the 2014 AICPA Conference on Current SEC and PCAOB Developments, the Division staff noted that it will accept less than five years of revenue presented on the basis of the new revenue standard in selected financial data (i.e., it will not require a registrant to retrospectively adjust the last two years). In doing so, the staff is encouraging registrants to use the full retrospective method of adoption because that method will yield information that is more helpful to financial statement users.
Section 8
FERC Enforcement Activities
In November 2014, the FERC Office of Enforcement (OE) issued its 2014 Report on Enforcement (the “2014 Report”), which provides information about the OE’s activities, including its auditing and monitoring of data reported by companies under its jurisdiction and its surveillance and analysis of the conduct of companies and individuals in wholesale natural gas and electricity markets. The report notes that in fiscal year 2015, the OE will continue to focus on its previously established priorities:

- “Fraud and market manipulation.”
- “Serious violations of the Reliability Standards.”
- “Anticompetitive conduct.”
- “Conduct that threatens the transparency of regulated markets.”

The OE developed these priorities to further the three primary goals of FERC’s strategic plan:

- To ensure that “rates, terms, and conditions of jurisdictional services are just, reasonable, and not unduly discriminatory or preferential.”
- To promote “the development of a safe, reliable, and efficient energy infrastructure that serves the public interest.”
- To facilitate “organizational excellence through increased transparency, communication, and managing [FERC] resources and employees.”

**Highlights**

In fiscal year 2014, the OE “opened 17 new investigations while bringing 15 pending investigations to closure with no action or settlement.” Further, FERC “approved 8 settlement agreements . . . and 9 separate subjects to resolve pending investigations.” The settlements comprised “almost $25 million in civil penalties, disgorgement of approximately $4 million plus interest, and $1.7 million in public safety enhancements.” In addition, the settlements included provisions requiring the improvement of compliance programs and making periodic reports to the OE “regarding the results of those compliance enhancements.” The monetary amount imposed in civil penalties and disgorgements represented a significant decline from the 2012 and 2013 levels for these figures, owing primarily to the fact that no settlements or disgorgements imposed for individual investigations in 2014 exceeded the $100 million mark, as had been the case in the previous two years.

FERC has also “approved settlement agreements . . . that resolved [open-access transmission tariff] violations by two entities, violations of Reliability Standards by two entities, violations of hydropower safety regulations by one entity, violations of [FERC’s] regulations regarding filings and facility merger/consolidation authorization by four affiliated entities, violations of prohibitions on submission of inaccurate information by one entity, and violations of [FERC’s] regulations prohibiting manipulation in natural gas and electric markets by two entities.”

Over the past fiscal year, FERC has enhanced its ability to oversee the gas and electric markets by gaining access to the Commodity Futures Trading Commission’s (CFTC’s) Large Trader Report data. In addition, FERC performed “an extensive review of the Polar Vortex events that occurred in January and February of 2014 to determine whether potentially manipulative trading behavior contributed to the high natural gas prices and elevated electricity costs.”
Activities by Enforcement Division

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

Investigations

In fiscal year 2014, OE’s Division of Investigations (DOI) directed FERC’s secretary “to issue 9 notices of alleged violations [against] 21 separate corporate entities and 6 individuals.” These violations involved market manipulation, tariffs, regulations, and reliability standards.

For example, FERC approved the settlement of an investigation of a violation of its anti-manipulation rules that was self-reported by Direct Energy Services LLC. FERC staff concluded that Direct Energy had manipulated prices in May 2012 “at Algonquin and Transco Zone 6 to benefit its related financial positions.” Although Direct Energy did not admit that it had committed the violations, it agreed to pay a civil penalty of $20,000 and to disgorge $31,935. Overall, Direct Energy “received a relatively small civil penalty and disgorgement payments due to its self-reporting, strong compliance program, quick action, and full cooperation with [the OE’s] investigation.”

In addition, FERC continued to focus on requiring reliability enhancements. For example, FERC approved a settlement related to a September 2011 blackout in parts of Arizona; Southern California; and Baja California, Mexico. The settlement included both a civil penalty and a requirement that more than $10 million be invested in reliability enhancements.

Audits

In fiscal year 2014, the OE’s Division of Audits and Accounting (DAA):

- Completed 19 audits of public utilities, natural gas pipelines, and storage companies (financial and nonfinancial).
- Employed, for the first time, a risk-based method to plan its audits. FERC used “internal and external sources of information to inform the risk-based audit candidate selection process.” Some examples of internal sources are...
“discussions with agency officials . . . and analysis of rate filings, financial forms, and reports,” while external sources include such items as compliance history and meetings, discussions, and filings with other regulatory agencies.

- “[S]hifted its efforts to provide oversight of audit-related activities by the Electric Reliability Organization (ERO), NERC and its eight Regional Entities, to ensure compliance with [FERC]-approved mandatory reliability standards.”

The 2014 report includes the following additional information about the DAA’s activity:

In FY2014, [the] DAA reviewed 345 [FERC] filings. These filings and applications included requests for accounting approval, certificate authorizations, mergers and acquisitions, security and debt authorizations, and rate filings. Also, DAA provided informal guidance on 85 inquiries related to various aspects of [FERC] accounting, financial reporting, and record retention regulations. These inquiries came from jurisdicational entities, industry stakeholders, and consultants, as well as through the [FERC’s] Compliance Help Desk, Office of External Affairs, Enforcement Hotline, and other [FERC] offices.

Audit Findings

Below are some of the areas in which the DAA has identified consistent patterns of noncompliance over the past several years (quotes are from the 2014 Report):

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

- Merger Goodwill — including goodwill in the equity component of the capital structure absent [FERC] approval;
- Depreciation Rates — using state-approved or a blended depreciation rate consisting of [FERC] and state-approved depreciation rates without [FERC] approval;
- Merger Costs — including any merger-related costs in rates (e.g., third-party advisory fees, internal labor, severance, and other general and administrative costs) without [FERC] approval;
- Tax Prepayments — incorrectly recording tax overpayments not applied to a future tax year’s obligation as a prepayment leading to excess recovery through working capital;
- Unused Inventory and Equipment – including the cost of materials, supplies, and equipment purchased for a construction project without removing the cost of items unused in whole or in part from the cost of a project;
- Allocated Labor – using labor cost allocators not based on a representative time study to determine the amount of indirect labor costs to distribute to construction projects;
- Asset Retirement Obligation (ARO) — including ARO amounts in formula rates, without explicit [FERC] approval;
- Below-the-Line Costs — including below-the-line costs in formula rates (e.g., lobbying, charitable contributions, fines and penalties, and compromise settlements arising from discriminatory employment practices) without [FERC] approval; and
- Improper Capitalization — seeking to include in rate base (and earn a return on) costs that should be expensed.”

Example Finding

From 2001 through 2012, [the Company] classified and reported $X in lobbying expenses in above-the-line accounts rather than in Account 426.4, Expenditures for Certain Civic, Political and Related Activities.

“Allowance for Funds Used During Construction. Recent audit activity has shown deficiencies in how jurisdicational entities have calculated the Allowance for Funds Used During Construction (AFUDC) rate including: inclusion of goodwill-related equity in determining the equity component of AFUDC; failure to include short-term debt in computing the AFUDC rate;
computing AFUDC on contract retention; inclusion of unrealized gains and losses from other comprehensive income; compounding of the rate more than semi-annually; and use of an AFUDC methodology not prescribed by [FERC].”

**Example Finding**

[The Company] included ineligible costs, such as contract retention fees and other unpaid amounts, in the construction base component of its AFUDC calculation. This resulted in [the Company] over-accruing AFUDC.

“Nuclear Decommissioning Trust Funds. Some public utilities owning nuclear assets have failed to: make required [FERC] filings; secure required documents upon acquisition of nuclear assets; and separately report the wholesale portions of jurisdictional funds invested in external trust funds.”

**Example Finding**

None of [Company A’s] Subsidiaries submitted NDTF annual reports for their three nuclear generating plants. In addition, neither [Company B] nor the [Company A] Subsidiaries maintained separate accounts for the [FERC]-jurisdictional monies for decommissioning trust funds.

“Open Access Transmission Tariffs. An essential goal of open access is to support efficient and competitive markets. On recent OATT audits, DAA noted instances where company actions did not support this goal. Specifically, incorrect rates were billed to customers, available transfer capacity data was inaccurately posted, transmission capacity was not released in accordance with [FERC] approved tariffs, and scheduling protocols to ensure appropriate transmission reservations over constrained interfaces were not consistently followed.”

**Example Finding**

[The Company] did not release to the market a transmission capacity set-aside for a five-megawatt long-term Point-to-Point (PTP) service agreement once it expired. [The Company] did not detect this error for 22 months, until it worked on audit staff’s data request.

**Market Oversight**

According to the 2014 Report, the OE’s Division of Energy Market Oversight (the “Division”) “continuously examines the structure and operation of [the nation’s wholesale natural gas and electric power markets] to identify market anomalies, flawed market rules, tariff and rule violations, and other unusual market behavior.” In addition, the Division oversees FERC’s filing requirements, reviewing submissions for:

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

In fiscal year 2014, FERC implemented a new Web-based system for filing EQRs. The new system automated more than 150 compliance checks in addition to the roughly 9,000 EQRs reviewed by FERC staff. The 2014 Report notes that FERC plans to release a second version of the EQR filing system “in the future” and that this version will include “major changes.”

The 2014 Report also indicates that the Division has “provided ongoing market support to” [FERC’s] Gas-Electric Coordination initiative. Such support includes industry outreach initiatives and subject-matter experts. With the help of these subject-matter experts, in November 2013, FERC passed a final rule allowing gas pipeline and electric transmission operators to share nonpublic information, thereby enhancing reliability. To safeguard confidentiality of nonpublic information and “protect against undue discrimination,” the final rule contains a no-conduit provision that prohibits disclosure of such information to an affiliate or a third party.
Analytics and Surveillance

In an effort to restore and enhance the analytic capability of the OE, FERC created the Division of Analytics and Surveillance (DAS) in February 2012. The DAS focuses on “(1) natural gas surveillance; (2) electric surveillance; and (3) transactional analysis.”

During fiscal year 2014, the DAS worked on over 30 investigations, including those initiated by the DOI. The 2014 Report notes that the DAS’s investigative activities typically consist of “(1) assessing market conditions during periods of suspected manipulation; (2) identifying patterns of market activity that could indicate market manipulation; (3) identifying time periods in which potentially manipulative activities occurred; (4) fully reconstructing and analyzing companies’ trading portfolios; and, (5) calculating the amount of unjust profits resulting from violations to assist with determining a civil penalty recommendation under [FERC’s] penalty guidelines.”

In addition, the DAS spearheaded the review of Polar Vortex events (see Highlights above). Using the CFTC’s Large Trader Report data, the DAS was able to “quickly and efficiently evaluate natural gas and electric market participants’ financial incentives during” these events. While the DAS staff “found no evidence of widespread or sustained market manipulation,” the OE began a nonpublic “investigation related to the formation of a single monthly natural gas index.” The purpose of this investigation is to examine “potential downward price manipulation.” Further, the OE “has opened two additional non-public investigations to determine whether certain generators may have improperly benefited from the constrained conditions in the electric markets.”

Other Developments

Memorandum of Understanding Under the Dodd-Frank Act

FERC’s role under the Dodd-Frank Act continues to remain uncertain. For example, the Dodd-Frank Act mandated that FERC and the CFTC sign a Memorandum of Understanding (MoU) by January 2011 to coordinate potentially overlapping jurisdictions. Although the agencies missed the deadline, they signed a new Dodd-Frank MoU in 2014.

However, the two regulators are often still at odds with one another, as demonstrated during the Amaranth/Brian Hunter case. In this case, the CFTC and FERC both charged Brian Hunter with manipulating the natural gas market. When FERC fined Mr. Hunter $30 million, he took the case to the U.S. Court of Appeals, after which the CFTC sided with Mr. Hunter, arguing that FERC lacked jurisdiction in the matter. The court ruled in favor of Mr. Hunter, and the CFTC proceeded to settle the case for $750,000 without requiring Mr. Hunter to admit his guilt. Three U.S. senators have since sent CFTC Chairman Timothy Massad a letter questioning the CFTC’s actions.
Section 9
Income Tax Update
Normalization — Deferred Tax Assets for Net Operating Loss and Minimum Tax Credit Carryforwards

The normalization debate regarding the proper treatment of DTAs for NOL carryforwards in ratemaking may involve:

- Whether the full amount of the depreciation-related DTL may reduce rate base despite the existence of an NOL carryforward (i.e., whether the DTA for the portion of an NOL carryforward attributable to accelerated depreciation must be included in rate base).

- How to compute the depreciation-related portion of a DTA for an NOL carryforward.

- Consideration of alternative approaches for reducing the revenue requirement when an NOL carryforward exists and some or all of the DTA for the NOL carryforward is included in rate base.

In 2014, the IRS released four private letter rulings addressing the application of the deferred tax normalization requirements when an NOL carryforward exists. The four rulings are summarized below.

The taxpayer in PLR 201418024 incurred taxable losses in excess of taxable income over a multiyear period and as of its test year had an NOL carryforward and an MTC carryforward (because utilization of alternative minimum tax NOL carryforwards is limited to 90 percent of alternative minimum taxable income). The amount of accelerated depreciation claimed in the two loss years exceeded the amount of NOLs incurred in those years. The utility filed a general rate case with plant-based DTL balances reduced by the amounts of tax not deferred as a result of the NOL and MTC carryforwards. The commission issued an order in which the rates were based on DTL balances unreduced by the effects of the carryforwards. In its analysis, the IRS stated that “[t]here is little guidance on exactly how an [NOL or MTC carryforward] must be taken into account in calculating” DTLs in accordance with the normalization requirements but that “it is clear that both must be taken into account” for ratemaking purposes. The ruling indicates that the commission “has stated that in setting rates it includes a provision for deferred taxes based on the entire difference between accelerated tax and regulatory depreciation, including situations in which a utility has” an NOL or MTC carryforward. This approach “allows a utility to collect amounts from ratepayers equal to income taxes that would have been due” in the absence of the NOL and MTC carryforwards. Although the IRS accepted these commission assertions as true for purposes of the ruling, it did not conclude that the commission had actually set rates in accordance with the assertions and indicated that the assertions “are subject to verification on audit.” Further, the IRS held that because the commission had already taken the NOL and MTC carryforwards into account in setting rates, the reduction of rate base by the full amount of the DTL account without regard to the balances of the carryforward accounts was consistent with the normalization requirements.

The taxpayer and its consolidated group in PLR 201436037 and PLR 201436038 incurred or expected to incur NOLs resulting in NOL carryforwards. The taxpayer computed the depreciation-related portion of its DTA by using a with-or-without method in which the NOL carryforward was considered “attributable to accelerated depreciation to the extent of the lesser of” the amount of accelerated depreciation or the NOL carryforward. Other rate-case participants proposed different approaches. For example, in PLR 201436037, a participant proposed an approach in which regulatory tax expense would be reduced by the amount of the DTA determined to be attributable to accelerated depreciation. In both rulings, the IRS stated that regulations clearly indicate that an entity must take into account the effects of an NOL carryforward attributable to accelerated depreciation in determining the rate base reduction for DTLs for normalization purposes but that the regulations provide “no specific mandate on methods.” The IRS further stated that the with-or-without method ensures that “the portion of the [NOL carryforward] attributable to accelerated depreciation is correctly taken into account by maximizing the amount of the [carryforward] attributable to accelerated depreciation.” Further, the method “prevents the possibility of ‘flow through’ of the benefits of accelerated depreciation to ratepayers.” The IRS ruled that reducing rate base by the full amount of the DTL account balances offset by a portion of the DTA for the NOL carryforward “that is less than the amount attributable to accelerated depreciation” calculated on a with-or-without basis would be inconsistent with
the normalization requirements. Moreover, in PLR 201436037, the IRS noted that any reduction to tax expense included in cost of service to reflect the tax benefit of an NOL carryforward would be inconsistent with the normalization requirements because such a reduction “would, in effect, flow through the tax benefits of accelerated depreciation deductions through to ratepayers even though the [taxpayer has not yet realized such benefits.”

The utility subsidiary in PLR 201438003 forecasted that it would incur an NOL resulting in an NOL carryforward in its test period. The DTL used to reduce rate base was reduced by the amount of the DTA for the NOL carryforward. The utility’s commission issued an order in which the commission held that it was inappropriate to include the DTA for the NOL carryforward in rate base but stated that it intends to comply with the normalization requirements and that it would allow the utility to seek a rate adjustment if the utility obtains a private letter ruling affirming the utility’s position that failure to reduce its rate-base offset for depreciation-related DTL by the DTA attributable to the NOL carryforward would be inconsistent with the normalization requirements. The IRS stated that regulations clearly indicate that an entity must take into account the effects of an NOL carryforward attributable to accelerated depreciation in determining the rate base reduction for DTLs for normalization purposes but that the regulations provide “no specific mandate on methods.” The IRS further stated that the with-or-without method ensures that “the portion of the [NOL carryforward] attributable to accelerated depreciation is correctly taken into account by maximizing the amount of the [carryforward] attributable to accelerated depreciation.” Further, the method “prevents the possibility of ‘flow through’ of the benefits of accelerated depreciation to ratepayers.” In this case, the IRS ruled that reducing rate base by the full amount of the DTL account balance unreduced by the balance of the DTA for the NOL carryforward would be inconsistent with the normalization requirements. In addition, the IRS ruled that use of a balance for the portion of the DTA for the NOL carryforward attributable to accelerated depreciation that is less than the amount computed on a with-and-without basis would be inconsistent with the normalization requirements. The IRS also held that “assignment of a zero rate of return to the balance” of the DTA for the NOL carryforward attributable to accelerated depreciation would be inconsistent with the normalization requirements.

Normalization — Deferred Investment Tax Credit and Excess Deferred Taxes (Depreciation Study)

In August 2013, the IRS published PLR 201334036, which addresses the rates at which (1) deferred ITCs may be amortized under the Option 2 ITC normalization requirements and (2) excess deferred federal income taxes (EDFIT) may be amortized under the average rate assumption method (ARAM). The taxpayer in this ruling performed a depreciation study in conjunction with a rate case filing. The revised depreciation rates reflected extensions in the lives of assets and formed the basis of regulatory depreciation expense in the rate case filing. However, after rates had become effective, the taxpayer discovered that it had inadvertently failed to extend the ITC amortization periods and the ARAM amortization of EDFIT to correspond to the extended depreciable lives. The practical effects of these errors were to provide lower rates to customers by flowing through ITC and EDFIT tax benefits as a reduction of regulatory tax expense more rapidly than prescribed by the normalization requirements. The taxpayer represented that it would correct its ITC amortization rates and EDFIT amortization rates in its next rate case filing.

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

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

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

In the rulings, the Option 2 taxpayers determined that for several years they had been applying the Option 1 approach in setting their formula rates even though they had elected to apply the Option 2 normalization requirements. The effect of the erroneous treatment of ADITC in the formula rate templates was a reduction in customer rates. At the time the ruling requests were filed, the taxpayers had not made formula filings with the corrected templates, but the taxpayers indicated that they would do so in their next annual filings.

The commission did not specifically address these matters in rate cases involving the taxpayers and did not issue orders on this matter during the periods in which ADITC was erroneously treated in the templates. The commission did not insist on the errors. The rulings noted that the taxpayers acted upon discovery of these errors and adjusted their templates so that the templates would reflect the same amounts as if no errors had occurred when filed. The IRS exercised its discretion not to disallow or recapture ITC. The IRS indicated that its analysis would not necessarily apply to rate orders finalized after the dates of the rulings.

Presenting an Unrecognized Tax Benefit When Tax Carryforwards Exist

In July 2013, the FASB issued ASU 2013-11, codified as ASC 740-10-45-10A and 45-10B and amendments to ASC 740-10-45-11 through 45-13, to provide guidance on financial statement presentation of a UTB when an NOL carryforward, a similar tax loss, or a tax credit carryforward exists. The FASB’s objective in issuing the ASU was to eliminate diversity in practice resulting from a lack of existing guidance on this topic in U.S. GAAP.

Under ASC 740-10-45-10A and 45-10B, an entity must present a UTB, or a portion of a UTB, in the financial statements as a reduction to a DTA for an NOL carryforward, a similar tax loss, or a tax credit carryforward except when either of the following conditions is met:

- An NOL carryforward, a similar tax loss, or a tax credit carryforward is not available as of the reporting date under the governing tax law to settle taxes that would result from the disallowance of the tax position.

- The entity does not intend to use the DTA for this purpose (provided that the tax law permits a choice).

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

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

**Accounting for Investments in Qualified Affordable Housing Projects**

In January 2014, the FASB issued ASU 2014-01 (in response to the EITF consensus on Issue 13-B), which modifies ASC 323-740’s measurement and presentation alternative for certain investments in affordable housing projects that qualify for the low-income housing tax credit (LIHTC). Under the ASU, entities can apply, as an accounting policy election, a proportional amortization method to LIHTC investments if the following conditions are met:

- “It is probable that the tax credits allocable to the investor will be available.”
- “The investor does not have the ability to exercise significant influence over the operating and financial policies of the limited liability entity.”
- “Substantially all of the projected benefits are from tax credits and other tax benefits (for example, tax benefits generated from the operating losses of the investment).”
- “The investor’s projected yield based solely on the cash flows from the tax credits and other tax benefits is positive.”
- “The investor is a limited liability investor in the limited liability entity for both legal and tax purposes, and the investor’s liability is limited to its capital investment.”

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

- “The reporting entity is in the business of entering into those other transactions.”
- “The terms of those other transactions are consistent with the terms of arm’s-length transactions.”
- “The reporting entity does not acquire the ability to exercise significant influence over the operating and financial policies of the limited liability entity as a result of those other transactions.”

Further, the ASU requires an entity to:

- Evaluate its eligibility to use the measurement and presentation alternative in ASC 323-740 at the time of initial investment on the basis of facts and conditions that exist as of that date.
- Reevaluate those conditions if either of the following occurs:
  - A “change in the nature of the investment (for example, if the investment is no longer in a flow-through entity for tax purposes).”
  - A “change in the relationship with the limited liability entity” that could cause the reporting entity to no longer meet the conditions described in ASC 323-740.
• Test an LIHTC investment accounted for under the alternative method for impairment when it is more likely than not that the investment will not be realized and measure an impairment loss as the amount by which the investment’s carrying amount exceeds its fair value.

• Disclose information about “the nature of its investments in qualified affordable housing projects, and the effect of the measurement of its investments in qualified affordable housing projects and the related tax credits on its financial position and results of operations.”

However, the ASU does not prescribe where an entity would present investments accounted for under the measurement and presentation alternative in its statement of financial position.

For public entities, the ASU is effective for annual periods beginning after December 15, 2014, and interim periods therein. For nonpublic entities, the ASU is effective for annual periods beginning after December 15, 2014, and interim and annual periods thereafter. Early adoption is permitted.

Entities that applied the effective-yield method to account for LIHTC investments under the alternative in ASC 323-740 are permitted to continue to do so, but only for investments already accounted for under that method. Otherwise, the guidance in the ASU must be applied retrospectively to all periods presented.

For reporting entities that meet the conditions, and that elect to use the proportional-amortization method, to account for investments in qualified affordable housing projects, all amendments in the ASU apply. For reporting entities that do not meet the conditions or that do not elect the proportional-amortization method, only the disclosure-related amendments in the ASU apply.
Section 10
Renewable Energy
Production Tax Credits, Investment Tax Credits, and Treasury Grants

Introduction

PTCs are calculated by using stated rates (e.g., 2014 wind production at 2.3 cents) multiplied by kWh generated during each of the first 10 years of operation. The American Recovery and Reinvestment Act (the “Recovery Act”), which was signed into law by President Obama in February 2009, extended the placed-in-service date requirement for PTCs for wind resource generation facilities through December 31, 2012, and for certain other renewable generation facilities through December 31, 2013. Further, in January 2013, the American Taxpayer Relief Act of 2012 (the “Relief Act”) extended the PTC eligibility of wind resource generation facilities with construction beginning before January 1, 2014, and amended the PTC termination dates for other qualified facilities from a placed-in-service date to a beginning-of-construction date. In addition, the December 2014 Tax Increase Prevention Act extended the PTC eligibility for qualified facilities, including wind generation plants, to facilities with construction beginning before January 1, 2015. The IRS is expected to issue administrative guidance in 2015 regarding the application of the amended beginning-of-construction rules.

The energy credit under IRC Section 48 is an ITC available for certain renewable energy facilities placed in service through specified dates. ITCs are calculated by using stated rates (e.g., 30 percent for wind and solar electric generation property) multiplied by the tax basis of the eligible property. The Recovery Act provides an irrevocable election under IRC Section 48(a)(5) that allows entities to claim an ITC instead of a PTC for most PTC-eligible facilities placed in service after December 31, 2008, as long as no PTC has been claimed for such property (e.g., 30 percent wind electric generation property). The depreciable tax basis of the property is reduced by 50 percent of any ITC claimed, and the ITC is subject to recapture if the related property is sold or otherwise ceases to operate within five years of being placed in service. The Relief Act amended the credit termination date rules for most PTC-eligible facilities for which an ITC is elected and extended the termination date for wind resource generation facilities. Renewable energy facilities eligible for an ITC include solar electric generation property and combined heat and power system property placed in service before January 1, 2017, as well as wind resource generation facilities, closed-loop biomass facilities, open-loop biomass facilities, geothermal energy facilities, landfill gas facilities, municipal waste facilities, hydropower facilities, and marine and hydrokinetic renewable energy facilities with construction beginning before January 1, 2014.

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

In July 2009, the Treasury published Payments for Specified Energy Property in Lieu of Tax Credits Under the American Recovery and Reinvestment Act of 2009 (the “program guidance”) and FAQs on Section 1603. The Treasury also issued “Begun Construction” FAQs, which clarify eligibility requirements for properties placed in service after December 31, 2011 (i.e., the construction of such properties must have begun in 2009, 2010, or 2011).

Applicants that submitted an initial application with the Treasury before October 1, 2012, under the Begun Construction provisions are required to file an updated application within 90 days after the energy property is placed in service. Applicants should be aware that the Treasury will not accept any final applications filed after 90 days. Like initial applications, all final applications with an eligible cost basis of $1 million or more must also include a certification from independent accountants. The Treasury will accept either an agreed-upon procedures report prepared by an independent accountant in accordance with AICPA AT Section 201 or an examination report on the schedule of eligible costs paid or incurred (depending on whether the taxpayer applies the cash method or accrual method) in accordance with AICPA AT Section 101.
The program guidance, FAQs, and instructions for preparing an agreed-upon procedures report are available on the Treasury Department’s Web site. Renewable energy providers should be aware that the Treasury’s recent intense scrutiny of qualifying costs has resulted in (1) longer review periods, (2) more frequent challenges to applications, (3) occasional delays in receiving cash, and (4) sequestration of awards. As communicated via a message on sequestration on the Treasury’s Web site, every award given to a Section 1603 grant applicant on or after October 1, 2013, and on or before September 30, 2014, will be reduced by 7.4 percent, irrespective of when the application was received by the Treasury. Further, on September 30, 2014, the Treasury updated the above message on sequestration, indicating that every award given to a Section 1603 grant applicant on or after October 1, 2014, and on or before September 30, 2015, will be reduced by 7.3 percent, irrespective of when the application was received by the Treasury. The sequestration reduction rate will be applied unless or until a law is enacted that cancels or otherwise affects the sequester, at which time the sequestration reduction rate is subject to change.

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

In May 2013, the IRS issued Notice 2013-29, which “provides guidelines and a safe harbor to determine when construction has begun” on facilities that are eligible to receive an ITC or a PTC in accordance with the Relief Act (the construction of the facility must have begun before January 1, 2014). Eligible facilities include wind facilities, closed-loop biomass facilities, open-loop biomass facilities, geothermal facilities, landfill gas facilities, trash facilities, hydropower facilities, and marine and hydrokinetic facilities (no changes were made to the requirements for solar ITCs). However, under Notice 2013-29, the facility must be in a continuous state of construction on the basis of the relevant facts and circumstances. The following is a summary of significant provisions of Notice 2013-29:

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

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

  If the total cost of a facility that is a single project comprised of multiple facilities (as described in section 4.04(2)) exceeds its anticipated total cost, so that the amount a taxpayer actually paid or incurred with respect to the facility before January 1, 2014, is less than five percent of the total cost of the facility at the time the facility is placed in service, the [safe harbor threshold] is not fully satisfied. However, [the safe harbor threshold] will be satisfied and the PTC or ITC may be claimed with respect to some, but not all, of the individual facilities (as described in section 4.04(1)) comprising the single project, as long as the total aggregate cost of those individual facilities is not more than twenty times greater than the amount the taxpayer paid or incurred before January 1, 2014.
In evaluating the 5 percent safe harbor provision, taxpayers may rely on suppliers’ statements regarding costs that the supplier has paid or incurred on the taxpayer’s behalf for property to be manufactured, constructed, or produced under a binding written contract. In determining when it has incurred costs, the supplier may consult the economic performance rules in IRC Section 461(h) (see Treas. Regs. Section 1.461-1(a)(1) and (2)). The supplier may use any reasonable method (the method’s reasonableness depends on the facts and circumstances) to allocate the costs it incurs among the units of property manufactured, constructed, or produced under a binding written contract for multiple units. If a subcontractor manufactures components for the supplier, the cost of those components is incurred only when the components are provided to the supplier (not when the subcontractor pays or incurs the costs). In the determination and allocation of costs, property that the supplier reasonably expects to receive from a subcontractor within three and a half months from the date of payment (supplier’s payment to subcontractor) is considered to be provided by the payment date.

In September 2013, the IRS issued Notice 2013-60, which clarifies the rules on beginning construction discussed above. Specifically, Notice 2013-60 explains that a facility meets the continuous construction criterion (to satisfy the physical work condition) or the continuous efforts criterion to meet the safe harbor threshold if the facility is placed into service before January 1, 2016. Notice 2013-60 also explicitly states that when a qualifying facility meets the physical work criterion or the safe harbor threshold, the taxpayer that owns the qualifying facility as of the in-service date is eligible for the credit, regardless of whether it owned the facility at the beginning of construction.

Further, in August 2014, the IRS issued Notice 2014-46, which clarifies the application of the physical work test, the effect of certain transfers, and the application of the safe harbor for facilities that have “incurred less than five percent, but at least three percent, of the total cost of the facility before January 1, 2014.” Regarding the physical work test, Notice 2014-46 indicates that the Notice 2013-29’s list of activities that constitute physical work is not all-inclusive and that any one of the activities in Section 4.02 (e.g., “the beginning of the excavation for the foundation, the setting of anchor bolts into the ground, or the pouring of the concrete pads of the foundation”); 4.05(1) (e.g., “[p]hysical work on a custom-designed transformer that steps up the voltage of electricity produced at the facility to the voltage needed for transmission”); or 4.05(2) (e.g., “[r]oads that are integral to the facility are integral to the activity performed by the facility”) would constitute physical work of a significant nature. In addition, Notice 2014-46 explains that the purpose of the example in Notice 2013-29 was to demonstrate the “single project” concept, not to provide a “work or monetary or percentage threshold” that would meet the physical work criterion.

To qualify for the PTC or ITC, a taxpayer who begins construction does not need to be the same taxpayer who places the qualifying facility in service. Notice 2014-46 distinguishes between transfers of fully or partially developed facilities and transfers of “just tangible” property (including contractual rights to such property). Specifically, Section 4.01 of the notice states:

Thus, except as provided in section 4.03 of this notice, a fully or partially developed facility may be transferred without losing its qualification under the Physical Work Test or the Safe Harbor for purposes of the PTC or the ITC. For example, a taxpayer may acquire a facility (that consists of more than just tangible personal property) from an unrelated developer that had begun construction of the facility prior to January 1, 2014, and thereafter the taxpayer may complete the development of that facility and place it in service. The work performed or amount paid or incurred prior to January 1, 2014, by the unrelated transferor developer may be taken into account for purposes of determining whether the facility satisfies the Physical Work Test or Safe Harbor.

Notice 2014-46 also clarifies the relocation of equipment by a taxpayer. For instance, a taxpayer may begin constructing a facility in 2013 but subsequently transfer the equipment to another site. The taxpayer may take the costs paid or incurred before January 1, 2014, into account in determining whether the facility satisfies the physical work criterion or the safe harbor threshold.

In addition, Notice 2014-46 indicates that if a taxpayer incurred at least 3 percent, but less than 5 percent, of the total costs of the project before January 1, 2014, to meet the physical work criterion, the taxpayer can claim the tax credit related to the costs incurred.

Taxpayers are advised to maintain a continuous program of construction (since the IRS will closely scrutinize taxpayers who claim that their facilities qualify for PTCs or ITCs under the provisions related to physical work of a significant nature). In addition, taxpayers should consider documenting events that are beyond their control as well as milestones, continuous
status of execution, engineering progress reports, and any delays encountered. Further, significant contracts, such as turbine supply and EPC agreements, should include recordkeeping requirements to demonstrate progress.

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

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

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

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

**Grant-Eligible ITC Claimed on QPEs**

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

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

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

**Applicability to Pass-Through Entities**

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

**Rate-Regulated Entities**

The Recovery Act initially stipulated that rate-regulated entities must apply the ITC normalization rules to Section 1603 grants, meaning that the benefits of the grants could not be passed back to customers faster than a plant’s book depreciable life. However, in late 2011, the National Defense Authorization Act for Fiscal Year 2012 retroactively eliminated the normalization provisions associated with cash grants. Accordingly, a regulator can reduce rates for the grants faster than the life of the property without violating the normalization rules. The ITC normalization rules continue to apply to ratemaking and accounting for the energy credit under IRC Section 48 claimed with respect to public utility property.

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

**Accounting for PTCs**

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

**Structuring Project Arrangements and the Resulting Accounting and Tax Implications**

Many renewable energy businesses are unable to fully use renewable energy tax benefits, including PTCs, ITCs, and accelerated depreciation, as a result of the absence of taxable income. Because of start-up activities, current economic conditions, changing tax rules or circumstances (e.g., eligibility for bonus depreciation), or less than ideal resource generation (e.g., wind, solar), an entity that has a direct or indirect ownership in a renewable energy project (herein referred to as a “renewable energy entity”) may be unable to take advantage of all the renewable energy tax benefits available. To address this challenge, entities often look for ways to monetize the value of their tax benefits.

For example, renewable energy entities sometimes enter into partnerships, or other structured arrangements, with “green” investors or investors looking to reduce their tax liability. Such arrangements, which are often called “partnership flip structures” or “tax equity structures” (and are herein referred to as “structures”), give both the renewable energy businesses and investors opportunities to maximize benefits and returns on investments.

**Motivation for Structures**

The motivation for renewable energy entities to enter into structures is simple — the arrangements allow them to monetize renewable energy tax benefits that otherwise might be lost or delayed because of insufficient taxable income. By entering into structures and allocating renewable energy tax benefits to investors, these entities are able to generate positive cash flows immediately by receiving cash in exchange for the benefits.

The early years of a renewable energy project that is owned and operated directly or indirectly by a renewable energy entity often do not generate enough taxable income for an entity to take advantage of the tax benefits. Consequently, these entities are typically unable to use such tax benefits and are required to analyze the likelihood of using any of the deferred tax benefits in accordance with ASC 740-10-30-2.

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

Investors in structures are typically entities with available cash for investing opportunities and high tax liabilities. Since the inception of structures a few years ago, these investors have evolved from the typical investment banks and insurance companies to foreign investors — who have become more active in renewable energy structures in the United States by using these investments to enter the U.S. market — and other commercial entities that are interested in investing in renewable energy. Such investors have available cash for investing opportunities and are able to use tax benefits.
Renewable energy entities have explored various funding options, but the most common approach is for an investor to invest cash upon inception of the arrangement. Investing in structures allows investors to offset tax liabilities and receive an attractive after-tax return on their investment. In addition, such investors are often predisposed to marketing themselves as “green,” and by entering into structures, they are able to market themselves as being environmentally friendly and focusing on renewable energy alternatives.

**Features of Traditional Structures**

Structures contain certain features that allow investors to receive favorable tax treatment. A common arrangement is a tax partnership in which the renewable energy entity and the investor hold interests in a partnership that directly owns and operates a renewable energy project. Under such an arrangement, the investor purchases the partnership interest for cash and is allocated a majority of the tax benefits (e.g., PTCs, accelerated depreciation) and cash flows generated by the renewable energy project for some defined period. Typically, at the end of the period, the renewable energy entity has the option, but is not required, to repurchase all of the investor’s partnership interest at its fair value as of the option exercise date. The tax benefits and cash flows allocated to the investor typically flip down from 99 percent to 5 percent before the repurchase option period, which makes the repurchase less expensive than it would be in a sale-leaseback arrangement. Such an arrangement allows both the renewable energy entity and the investor to maximize the renewable energy tax benefits. The renewable energy entity monetizes unused tax credits and tax depreciation, while the investor receives tax benefits to offset its tax liability.

One variable of structures is the timing of the cash receipts from an investor. An investor typically would make a small up-front cash payment upon the formation of the partnership, followed by a substantial cash payment to the partnership to coincide with the commercial operation of the renewable energy project. The amount of cash is meant to capture the expected tax benefits that the investor will receive throughout the life of the structure.

The features of structures described above are consistent with those described in IRS Revenue Procedure (“Rev. Proc.”) 2007-65 (herein referred to as “traditional structures”). Issued in October 2007, Rev. Proc. 2007-65 provides a safe harbor for partnership arrangements between a renewable energy entity and one or more investors with the project company owning and operating the renewable energy project by identifying the economic terms that must be present in structures, including the following:

- Throughout the life of the structure, the renewable energy business has at least a 1 percent interest in partnership income, gains, deductions, losses, and credits (including PTCs).
- Throughout the life of the structure, the investor has at least a 5 percent interest in partnership income and has gains equal to at least 5 percent of its largest such interest.
- The investor’s allocation of renewable energy tax benefits cannot be guaranteed.
- When the project is 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 entity to purchase its partnership interest (i.e., a put option); however, five years after the placed-in-service date (determined in accordance with federal income tax rules), the renewable energy entity may have the ability (but may not be required) to repurchase the investor’s tax partnership interest at fair value (i.e., a call option).
- The renewable energy entity cannot lend to, or guarantee, the investor’s investment in the partnership.

As long as the safe harbor provisions in Rev. Proc. 2007-65 are met, the IRS will not challenge the validity of the partnership for federal income tax purposes or the allocation of renewable energy tax benefits. Although the features described in
Rev. Proc. 2007-65 specifically apply to wind partnerships with PTCs, they are also often copied in structures for other types of renewable energy partnerships (e.g., solar and biomass) and for other types of tax credits (e.g., ITCs).

### Accounting and Reporting Considerations for Traditional Structures

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

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

1. **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.

2. **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.

3. **The sale or transfer of an investment in the form of a financial asset that is in substance real estate.**

On the basis of the guidance in ASC 360-20-15-4 through 15-8, a renewable energy project typically is considered integral equipment, in which case the sale of the related partnership interest would be within the scope of ASC 360-20-15-3.

ASC 360-20 explains that two criteria must be met for an entity to use the full accrual method to recognize profit when real estate (or in-substance real estate) is sold: (1) the profit must be determinable and (2) the earnings process must be substantially complete.

ASC 360-20-40-3 states, in part:

- **Profit shall be recognized in full when real estate is sold, provided that both of the following conditions are met:**
  1. 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.
  2. 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 an entity cannot use the full accrual method to recognize revenue because the structure does not meet one or more of the criteria in ASC 360-20-40-5, a renewable energy entity must account for the sale of the partnership interest under another method described in ASC 360-20-40-28 through 40-64. Primarily because of the existence of the repurchase option held by the renewable energy entity (described in Features of Traditional Structures above), a sale of a partnership interest in a renewable energy project is likely to be accounted for under an approach other than the full accrual method (e.g., deposit, financing, leasing, profit-sharing). However, ASC 360-20 is silent on the mechanics and application of a method other than the full accrual method in a sale of (in-substance) real estate. In practice, profit-sharing and financing methods have been used to account for traditional structures. In selecting the appropriate method to use under ASC 360-20, a renewable energy entity must consider the specific facts and circumstances associated with the structure, including its substance and economics.

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

The accounting and reporting considerations discussed above apply to renewable energy entities. An investor would need to determine whether a structure constitutes equity or a debt security. If the investor concludes that a structure constitutes equity with no readily determinable fair value, it would need to determine whether it exercises significant influence over the investee in accordance with ASC 323-10, in which case it would apply equity method accounting. If, however, an investor concludes that a structure constitutes a debt security, it would classify and account for the structure in accordance with ASC 320-10.
Both renewable energy entities and investors need to evaluate structures under ASC 810 to determine whether the partnership or the renewable energy project is a variable interest entity and, ultimately, which party is required to consolidate the partnership that is contained in such structures.

Variations on Traditional Structures

The terms and form of structures have continued to evolve as a result of such factors as current market conditions, the availability and types of investors, fast-approaching deadlines to qualify for renewable energy tax benefits, and pending legislation affecting the industry as a whole (e.g., the CSPAR). Accordingly, variations on traditional structures have become more common over the past few years.

Put Options and Withdrawal Rights

Certain investors are subject to regulatory requirements under which they must demonstrate their ability to exit certain categories of investment (e.g., structures discussed herein) at a specified time (e.g., 10 years after the inception of the arrangement). One way for investors to demonstrate such ability is to hold a put option in the structures. The exercise price of the put option typically (1) is the lower of a fixed amount or the fair value of the investor’s partnership interest as of the exercise date and (2) does not provide an economic incentive for the investor to exercise the option.

A variation on a put option in structures is the presence of withdrawal rights, which are based on traditional common law or state law and represent an investor's right to withdraw from a partnership. The features of the exercise price for withdrawal rights are similar to those for put options. Withdrawal rights, however, are different from put options in that (1) withdrawal rights are not based on a regulatory requirement and (2) the only recourse for investors holding withdrawal rights is to the project assets (i.e., renewable energy projects), not to other partners (i.e., other investors, renewable energy entities) or other third parties.

Accounting Considerations

An entity should analyze the existence of a put option (or withdrawal right) within a partnership agreement to determine whether the substance and economics of the arrangement are equity- or liability-like. In performing such an analysis, the entity might wish to consider the guidance in ASC 480. In addition, renewable energy entities should apply ASC 815-15 to determine whether a put option (or withdrawal right) represents an embedded derivative in the partnership agreement that must be bifurcated.

Tax Considerations

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

Other Variations

In addition to put options and withdrawal rights, variations (not all-inclusive) in the features of traditional structures may include:

- Preset cash distribution ratios among the renewable energy entity and investors from the inception of the arrangement or upon the occurrence of an event specified in the partnership agreement.

- Predetermined date (as opposed to the achievement of a target internal rate of return on the investment in the partnership) that triggers the change in the allocation of tax benefits and cash distributions among the renewable energy entity and investors.

- Fixed ownership percentages among the members over the life of the partnership.
• A requirement for the partnership to distribute a fixed percentage of available cash (as defined in the partnership agreement) as preferred cash distribution to the investors before available cash is distributed to members of the partnership.

The accounting considerations for traditional structures (discussed above) also apply to arrangements containing variations on features of traditional structures.

**Other Accounting Considerations**

Depending on how both renewable energy entities and investors would account for the features of structures (described in Features of Traditional Structures and Variations on Traditional Structures above), it may be necessary to allocate income/loss (determined in accordance with GAAP) and cash distributions of the partnership to a renewable energy entity and investors at varying percentages at different times or upon the occurrence of certain events. Income/loss may be allocated in accordance with ASC 810-10 between the controlling and noncontrolling interest holders, or an equity method investor’s share of the partnership’s income/loss may be recorded in accordance with ASC 323-10. While ASC 810-10 is silent on the method to use for such income/loss allocation, ASC 323-10 prescribes allocation methods for investors, as discussed below.

Under the traditional equity method prescribed by ASC 323-10, income/loss would be allocated on the basis of preset ownership percentages for simple equity structures. Applying the traditional equity method to structures is generally challenging, because it does not adequately incorporate the structures’ complexities, including the varying allocations of income/loss and cash at different times or upon the occurrence of specified events.

When an investor receives allocations of income/loss that are disproportionate to its equity interest in the investee (such as that found in structures), it may not be appropriate to record equity method income/loss on the basis of the percentage of equity interest owned. Under ASC 323-10 and ASC 970-323-35-17, such arrangements should be “analyzed to determine how an increase or decrease in net assets of the venture (determined in conformity with GAAP) will affect cash payments to the investor over the life of the venture and on its liquidation.” The application of these principles often results in the use of the hypothetical liquidation at book value (HLBV) method.

The HBLV method is a balance-sheet-oriented approach for determining the allocation of GAAP equity and income/loss. Under this method, GAAP income/loss is allocated to each investor on the basis of the change during the reporting period of the amount each investor is entitled to claim in a liquidation scenario, which effectively indicates how much better (or worse) off the investor is at the end of the period than at the beginning of the period.

Renewable energy entities and their investors commonly use the HLBV method when allocating GAAP equity and income/loss on the basis of the features of structures described in the partnership agreements. Because features in structures are generally dominated by the value of the tax benefits being monetized, application of the HLBV method to allocate GAAP equity and income/loss in structures often incorporates tax concepts. Further, the underlying mechanics of the HLBV method largely depend on the terms of the partnership agreement and any interpretations thereof, which may involve the use of judgment. Thus, entities should tailor the components and mechanics incorporated into the HLBV calculation to properly reflect the facts and circumstances of each structure.

Certain variations on features found in traditional structures may lend themselves to the application of the traditional equity method or a variation thereof (e.g., one that is based on a preset ratio of cash distributions among the members) with respect to allocation of income/loss of a partnership to a renewable energy entity and its investors. In the context of structures, a method for allocating a partnership’s income/loss should reflect the economics and substance of the arrangements at inception and over the life of a structure. Although the accounting literature does not advocate a “one size fits all” approach, it is not appropriate to adjust the allocation method without a robust rationale supporting such a change (e.g., a change in the expected economics of the structure during its remaining life).

**Deferred Tax Considerations**

Renewable energy entities typically elect to be taxed as a partnership at the federal income tax level, in which case the federal income tax liabilities are passed through to the members of the partnership. In such circumstances, the tax-related
activity would not be reflected in the financial statements of the renewable energy entity if it is a pass-through entity for tax purposes.

Investors in structures are often entities with significant federal income tax liabilities; therefore, the features in structures are designed such that these investors would receive a majority of the tax benefits generated by the renewable energy project. Accordingly, temporary and permanent differences resulting from investments in structures are expected to arise, and investors need to consider the related income tax effects in accordance with ASC 740.

When an investor accounts for its interest in a structure under the equity method, there may be circumstances in which the balance of an investor’s investment in an investee differs from the investor’s claim on the book value of the investee. This difference is referred to as the investor basis difference. ASC 323-10-35-13 requires entities to account for this basis difference as if the investee were a consolidated subsidiary. That is, entities (investors) would need to determine the difference between the cost of their equity method investment and their share of the fair value of the investee’s individual assets and liabilities by applying the acquisition method of accounting in accordance with ASC 805.

Moreover, because equity method investments are presented as a single consolidated amount in the financial statements in accordance with the equity method of accounting, the tax effects attributable to basis differences are not presented separately in the investor’s financial statements as individual DTAs and DTLs; rather, such tax effects would become a component of this single consolidated amount in the financial statements.

**Accounting for Traditional Structures Under IFRSs**

One difference between U.S. GAAP and IFRSs concerns the application of ASC 360-20 to traditional structures under U.S. GAAP (discussed above in Accounting and Reporting Considerations for Traditional Structures). IFRSs do not currently contain any equivalent accounting guidance. When entities apply ASC 360-20 under U.S. GAAP, the investor’s interest in a traditional structure may ultimately, for example, be accounted for in equity (rather than as a liability).

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

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

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

U.S. GAAP and IFRSs also differ in their treatment of tax credits in traditional structures, such as PTCs. Under U.S. GAAP (ASC 740-10), investors (typically taxable entities for federal income tax purposes) are required to record tax credits earned as a component of deferred or current federal income tax expense in their financial statements. As discussed above, renewable energy entities often elect to be taxed as pass-through entities for federal income tax purposes; therefore, their financial statements would generally not include such tax credits as a component of deferred or current federal income tax expense. In contrast, because the accounting for tax credits is outside the scope of IAS 12 and most entities have accounted for tax credits on the basis of their nature and substance under IFRSs, tax credits may be recorded outside of the tax accounts.
While there are significant differences between the accounting for traditional structures under U.S. GAAP and that under IFRSs, entities should consider all relevant facts and circumstances in determining the appropriate accounting under each framework.

Renewable Energy

Start-Up Versus Development Costs and Timing of Capitalization

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

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

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

a. Opening a new facility

b. Introducing a new product or service

c. Conducting business in a new territory

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

e. Initiating a new process in an existing facility

f. Commencing some new operation.”

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

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

Construction costs are necessary costs incurred to prepare an asset for its intended use. Virtually all costs incurred in a project’s construction phase are capitalizable. Capitalization should cease on the commercial operation date. Potentially capitalizable construction costs may include EPC contractor fees; interest paid to third parties; test power costs and the related income (for short periods); internal costs directly related to the project; property tax incurred during the construction period; bonuses paid to the development team; and, in certain circumstances, development fees.
Certain late-stage development activities are likely to continue to take place after a project achieves commercial operation and may last up to a couple of years after the post-commercial-operation stage begins. Costs associated with late-stage development generally are related to employee training to operate and maintain the project, equipment fine-tuning, and contract negotiation concerning project operation. These costs are generally not capitalizable.

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

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

It is also important to understand how to account for revenues generated before commercial operations. For instance, once project construction is substantially complete, the related assets generally must be commissioned before commercial operations commence. As part of standard tests during the commissioning process, electricity will be generated. Once completed, the asset is shut down and certified and control is transferred from the manufacturer to the owner/operator upon the latter’s signature of acceptance. All revenues produced before the owner/operator’s acceptance of the project assets are considered test revenue. Test revenue is treated as a reduction of construction work-in-process in accordance with ASC 970-10-20, which states that “[r]evenue-producing activities engaged in during the holding or development period . . . reduce the cost of developing the property for its intended use, as distinguished from activities designed to generate a profit or a return from the use of the property.”

Example

Upon the near-completion of a wind turbine project, the turbines must be commissioned before being placed into commercial operation. As part of standard tests that are performed during the commissioning process, each wind turbine will produce some amount of electricity. Once the testing is complete, the turbine is shut down, a turbine completion certificate (TCC) is issued by the manufacturer, and the manufacturer relinquishes control of the turbine and transfers it to the owner/operator upon the latter’s signature of acceptance. All revenues produced by a particular wind turbine before the owner’s official acceptance of the TCC are considered test revenue and accounted for as a reduction of construction work-in-process in accordance with ASC 970-10-20.

Further, entities should develop a capitalization policy in accordance with ASC 360, ASC 720, and ASC 835 and apply this policy consistently to all of their projects. A best practice for capitalization policies is to incorporate entity-specific considerations, including factors affecting management’s judgment about properly accounting for start-up and development costs. At a minimum, entities should consider incorporating the following into their capitalization policy:

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

<table>
<thead>
<tr>
<th>Abbreviation</th>
<th>Description</th>
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<tbody>
<tr>
<td>AcSB</td>
<td>Canadian Accounting Standards Board</td>
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<tr>
<td>ADITC</td>
<td>accumulated deferred investment tax credit</td>
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<tr>
<td>AFS</td>
<td>available for sale</td>
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<tr>
<td>AGA</td>
<td>American Gas Association</td>
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<tr>
<td>AICPA</td>
<td>American Institute of Certified Public Accountants</td>
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<tr>
<td>AOCI</td>
<td>accumulated other comprehensive income</td>
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<tr>
<td>ARAM</td>
<td>average rate assumption method</td>
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<tr>
<td>ARM</td>
<td>attrition relief mechanism</td>
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<tr>
<td>ASC</td>
<td>FASB Accounting Standards Codification</td>
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<tr>
<td>ASU</td>
<td>FASB Accounting Standards Update</td>
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<tr>
<td>B&amp;G</td>
<td>blend and extend</td>
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<tr>
<td>Bcf/d</td>
<td>billion cubic feet per day</td>
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<tr>
<td>Btu</td>
<td>British thermal unit</td>
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<tr>
<td>CAIR</td>
<td>Clean Air Interstate Rule</td>
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<td>CAISO</td>
<td>California Independent Service Operator</td>
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<td>CapEx</td>
<td>capital expenditure</td>
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<td>CCIF</td>
<td>Critical Consumer Issues Forum</td>
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<tr>
<td>CCR</td>
<td>coal combustion residual</td>
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<tr>
<td>CECL</td>
<td>current expected credit loss</td>
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<tr>
<td>CFE</td>
<td>Comisión Federal de Electricidad (Mexico)</td>
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<tr>
<td>CFTC</td>
<td>Commodity Futures Trading Commission</td>
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<tr>
<td>CMR</td>
<td>conflict materials report</td>
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<tr>
<td>CO₂</td>
<td>carbon dioxide</td>
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<td>CPI</td>
<td>consumer price index</td>
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<tr>
<td>CPP</td>
<td>Clean Power Plan</td>
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<tr>
<td>CRISP</td>
<td>Cybersecurity Risk Information Sharing Program</td>
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<td>CSAPR</td>
<td>Cross-State Air Pollution Rule</td>
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<td>CWIP</td>
<td>construction work in progress</td>
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<tr>
<td>DAA</td>
<td>FERC’s Office of Enforcement Division of Audits and Accounting</td>
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<tr>
<td>DAS</td>
<td>FERC’s Office of Enforcement Division of Analytics and Surveillance</td>
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<tr>
<td>DG</td>
<td>distributed generation</td>
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<tr>
<td>DHS</td>
<td>Department of Homeland Security</td>
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<tr>
<td>DOE</td>
<td>U.S. Department of Energy</td>
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<tr>
<td>DOI</td>
<td>FERC’s Office of Enforcement Division of Investigations</td>
</tr>
<tr>
<td>DP</td>
<td>discussion paper</td>
</tr>
<tr>
<td>Abbreviation</td>
<td>Description</td>
</tr>
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<td>--------------</td>
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<tr>
<td>DRC</td>
<td>Democratic Republic of the Congo</td>
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<tr>
<td>DSE</td>
<td>development-stage entity</td>
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<tr>
<td>DTA</td>
<td>deferred tax asset</td>
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<tr>
<td>DTL</td>
<td>deferred tax liability</td>
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<tr>
<td>EBITDA</td>
<td>earnings before interest, taxes, depreciation, and amortization</td>
</tr>
<tr>
<td>ED</td>
<td>exposure draft</td>
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<tr>
<td>EDFIT</td>
<td>excess deferred federal income taxes</td>
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<td>EEI</td>
<td>Edison Electric Institute</td>
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<tr>
<td>EGC</td>
<td>emerging growth company</td>
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<tr>
<td>EGU</td>
<td>electric generating unit</td>
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<tr>
<td>EIA</td>
<td>U.S. Energy Information Administration</td>
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<tr>
<td>EIM</td>
<td>Western U.S. Energy Imbalance Market</td>
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<tr>
<td>EITF</td>
<td>Emerging Issues Task Force</td>
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<tr>
<td>EPA</td>
<td>Environmental Protection Agency</td>
</tr>
<tr>
<td>EPC</td>
<td>engineering, procurement, construction</td>
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<tr>
<td>EQR</td>
<td>Electric Quarterly Report</td>
</tr>
<tr>
<td>ERCOT</td>
<td>Electric Reliability Council of Texas</td>
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<tr>
<td>ERO</td>
<td>Electric Reliability Organization</td>
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<tr>
<td>FAQs</td>
<td>frequently asked questions</td>
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<td>FASB</td>
<td>Financial Accounting Standards Board</td>
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<tr>
<td>FERC</td>
<td>Federal Energy Regulatory Commission</td>
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<tr>
<td>FPA</td>
<td>Federal Power Act</td>
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<tr>
<td>FRM</td>
<td>SEC’s Division of Corporation Finance Financial Reporting Manual</td>
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<tr>
<td>FVTNI</td>
<td>fair value through net income</td>
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<tr>
<td>FVTOCI</td>
<td>fair value through other comprehensive income</td>
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<tr>
<td>GAAP</td>
<td>generally accepted accounting principles</td>
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<tr>
<td>GDP</td>
<td>gross domestic product</td>
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<td>GP</td>
<td>general partner</td>
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<tr>
<td>GW</td>
<td>gigawatt</td>
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<tr>
<td>HLBV</td>
<td>hypothetical liquidation at book value</td>
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<td>IAS</td>
<td>International Accounting Standard</td>
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<tr>
<td>IASB</td>
<td>International Accounting Standards Board</td>
</tr>
<tr>
<td>ICFR</td>
<td>internal control over financial reporting</td>
</tr>
<tr>
<td>IFRS</td>
<td>International Financial Reporting Standard</td>
</tr>
<tr>
<td>IMF</td>
<td>International Monetary Fund</td>
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<td>IPO</td>
<td>initial public offering</td>
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<td>IPSA</td>
<td>independent private-sector audit</td>
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<td>Description</td>
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<td>IRC</td>
<td>Internal Revenue Code</td>
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<tr>
<td>IRS</td>
<td>Internal Revenue Service</td>
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<td>ISO</td>
<td>Independent System Operator</td>
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<tr>
<td>ISO-NE</td>
<td>ISO New England Inc.</td>
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<tr>
<td>ITC</td>
<td>investment tax credit</td>
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<tr>
<td>kWh</td>
<td>kilowatt hour</td>
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<tr>
<td>LCM</td>
<td>lower of cost or market</td>
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<tr>
<td>LIHTC</td>
<td>low-income housing tax credits</td>
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<td>LLC</td>
<td>limited liability company</td>
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<td>LMP</td>
<td>locational marginal pricing</td>
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<td>liquefied natural gas</td>
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<td>LP</td>
<td>limited partner</td>
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<td>M&amp;A</td>
<td>mergers and acquisitions</td>
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<td>MATS</td>
<td>Mercury and Air Toxics Standards</td>
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<td>MISO</td>
<td>Midcontinent (formerly Midwest) Independent Transmission System Operator Inc.</td>
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<td>MD&amp;A</td>
<td>Management’s Discussion and Analysis</td>
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<td>MLP</td>
<td>master limited partnership</td>
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<td>MMBtu</td>
<td>million Btu</td>
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<td>MMF</td>
<td>money market fund</td>
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<td>MoU</td>
<td>Memorandum of Understanding</td>
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<tr>
<td>MTC</td>
<td>minimum tax credit</td>
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<td>MW</td>
<td>megawatt</td>
</tr>
<tr>
<td>MWh</td>
<td>megawatt hour</td>
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<td>NAAQS</td>
<td>National Ambient Air Quality Standards</td>
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<td>NARUC</td>
<td>National Association of Regulatory Utility Commissioners</td>
</tr>
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<td>NASUCA</td>
<td>National Association of State Utility Consumer Advocates</td>
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<td>NAV</td>
<td>net asset value</td>
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<tr>
<td>NCI</td>
<td>noncontrolling interest</td>
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<td>NEPA</td>
<td>National Environmental Policy Act</td>
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<td>NERC</td>
<td>North American Electric Reliability Corporation</td>
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<td>NETO</td>
<td>New England Transmission Owners</td>
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<td>NIST</td>
<td>National Institute of Standards and Technology</td>
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<tr>
<td>NOL</td>
<td>net operating loss</td>
</tr>
<tr>
<td>NOₓ</td>
<td>nitrogen oxides</td>
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<tr>
<td>NPNS</td>
<td>normal purchase normal sale</td>
</tr>
<tr>
<td>NRC</td>
<td>Nuclear Regulatory Commission</td>
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<td>NYISO</td>
<td>New York ISO</td>
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<tr>
<td>Abbreviation</td>
<td>Description</td>
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<td>--------------</td>
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</tr>
<tr>
<td>O&amp;M</td>
<td>operations and maintenance</td>
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<tr>
<td>OCI</td>
<td>other comprehensive income</td>
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<tr>
<td>OE</td>
<td>FERC Office of Enforcement</td>
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<tr>
<td>P&amp;U</td>
<td>power and utilities</td>
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<tr>
<td>PBE</td>
<td>public business entity</td>
</tr>
<tr>
<td>PCAOB</td>
<td>Public Company Accounting Oversight Board</td>
</tr>
<tr>
<td>PCC</td>
<td>FASB’s Private Company Council</td>
</tr>
<tr>
<td>PCI</td>
<td>purchased credit-impaired</td>
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<tr>
<td>PJM</td>
<td>represents RTO that coordinates the movement of wholesale electricity in all or parts of 13 states and the District of Columbia</td>
</tr>
<tr>
<td>PLR</td>
<td>IRS private letter ruling</td>
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<tr>
<td>PPA</td>
<td>power purchase agreement</td>
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<tr>
<td>PP&amp;E</td>
<td>property, plant, and equipment</td>
</tr>
<tr>
<td>PTC</td>
<td>production tax credit</td>
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<tr>
<td>PV</td>
<td>photovoltaic</td>
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<tr>
<td>QPE</td>
<td>qualified progress expenditure</td>
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<tr>
<td>RCC</td>
<td>readily convertible to cash</td>
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<tr>
<td>REC</td>
<td>renewable energy certificate</td>
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<td>REIT</td>
<td>real estate investment trust</td>
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<td>Rev. Proc.</td>
<td>IRS Revenue Procedure</td>
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<td>RMI</td>
<td>Rocky Mountain Institute</td>
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<td>ROE</td>
<td>return on equity</td>
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<td>ROU</td>
<td>right of use</td>
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<td>RTO</td>
<td>Regional Transmission Organization</td>
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<td>SAB</td>
<td>SEC Staff Accounting Bulletin</td>
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<tr>
<td>SD</td>
<td>swap dealer</td>
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<td>SCED</td>
<td>security-constrained economic dispatch</td>
</tr>
<tr>
<td>SEC</td>
<td>Securities and Exchange Commission</td>
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<td>SO₂</td>
<td>sulfur dioxide</td>
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<td>SPP</td>
<td>Southwest Power Pool Inc.</td>
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<tr>
<td>TCC</td>
<td>turbine completion certificate</td>
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<tr>
<td>TRG</td>
<td>transition resource group</td>
</tr>
<tr>
<td>TVA</td>
<td>Tennessee Valley Authority</td>
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<tr>
<td>UTB</td>
<td>unrecognized tax benefit</td>
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<tr>
<td>VIE</td>
<td>variable interest entity</td>
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<tr>
<td>XBRL</td>
<td>eXtensible Business Reporting Language</td>
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The following is a list of short references for the Acts mentioned in this publication:

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<thead>
<tr>
<th>Abbreviation</th>
<th>Act</th>
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<tbody>
<tr>
<td>Dodd-Frank Act</td>
<td>Dodd-Frank Wall Street Reform and Consumer Protection Act</td>
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<tr>
<td>Hart-Scott-Rodino Act</td>
<td>Hart-Scott-Rodino Antitrust Improvements Act of 1976</td>
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<tr>
<td>JOBS Act</td>
<td>Jumpstart Our Business Startups Act</td>
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<td>Relief Act</td>
<td>American Taxpayer Relief Act of 2012</td>
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<td>Securities Act</td>
<td>Securities Act of 1933</td>
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<tr>
<td>Trust Indenture Act</td>
<td>Trust Indenture Act of 1939</td>
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Appendix B — Titles of Standards and Other Literature

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

**FASB Literature**

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

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

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

**International Standards**

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

- International Accounting Standards (IAS).

IASB Exposure Draft, *Rate-regulated Activities*

**PCAOB Literature**

- Auditing Standard 11, *Consideration of Materiality in Planning and Performing an Audit*
- Auditing Standard 17, *Auditing Supplemental Information Accompanying Audited Financial Statements*
- Auditing Standard 18, *Related Parties, Amendments to Certain PCAOB Auditing Standards Regarding Significant Unusual Transactions, and Other Amendments to PCAOB Auditing*
- AU Section 341, *The Auditor’s Consideration of an Entity’s Ability to Continue as a Going Concern*

**SEC Literature**

- Final Rules, Interim Final Rules, Proposed Rules, and Interpretive Releases:
  - Final Rule No. 33-9616, *Money Market Fund Reform; Amendments to Form PF*
  - Final Rule No. 33-9638, *Asset-Backed Securities Disclosure and Registration*
  - Final Rule No. 34-67716, *Conflict Minerals*
  - Final Rule No. 34-72472, *Interpretation, Application of “Security-Based Swap Dealer” and “Major Security-Based Swap Participant” Definitions to Cross-Border Security-Based Swap Activities*
  - Interim Final Rule No. 33-9545, *Extension, Extension of Exemptions for Security-Based Swaps*
o Proposed Rule, No. 33-9497, *Proposed Rule Amendments for Small and Additional Issues Exemptions Under Section 3(b) of the Securities Act*

o Proposed Rule No. 34-71958, *Recordkeeping and Reporting Requirements for Security-Based Swap Dealers, Major Security-Based Swap Participants, and Broker- Dealers; Capital Rule for Certain Security-Based Swap Dealers*

• Forms:
  o Form 8-K, “Current Reports”: Item 4.01, “Changes in Registrant’s Certifying Accountant”
  o Form 10-K, “General Form of Annual Report”
  o Form 10-Q, “Quarterly Report Pursuant to Sections 13 or 15(d)” of the Exchange Act
  o Form SD, “Specialized Disclosure Report”

• Regulation A, “Conditional Small Issues Exemption”

• Regulation D, “Rules Governing the Limited Offer and Sale of Securities Without Registration Under the Securities Act of 1933”


• Regulation S-K:
  o Item 301, “Selected Financial Data”
  o Item 1100, “Asset-Backed Securities (Regulation AB)”

• Regulation S-X:
  o Rule 3-05, “Financial Statements of Businesses Acquired or to Be Acquired”
  o Rule 3-09, “Separate Financial Statements of Subsidiaries Not Consolidated and 50 Percent or Less Owned Persons”
  o Rule 3-14, “Special Instructions for Real Estate Operations to Be Acquired”
  o Rule 4-08(e), “General Notes to Financial Statements: Restrictions Which Limit the Payment of Dividends by the Registrant”
  o Rule 5-04, “What Schedules Are to Be Filed”
  o Rule 12-04, “Condensed Financial Information of Registrant”

• SEC Staff Accounting Bulletins:
  o Topic 1.M (SAB 99), “Materiality”
  o Topic 5.J, “New Basis of Accounting Required in Certain Circumstances” (Removed by SAB 115)
  o Topic 10.E, “Classification of Charges for Abandonments and Disallowances”
  o Topic 13, “Revenue Recognition”

- Securities Exchange Act of 1934 Rules:
  - Rule 12a-11, “Exemption of Security-Based Swaps Sold in Reliance on Securities Act of 1933 Rule 240 (§ 230.240) From Section 12(A) of the Act”
  - Rule 12h-1, “Exemptions From Registration Under Section 12(g) of the Act”

- Trust Indenture Act of 1939 Rules:
  - Rule 4d-12, “Exemption for Security-Based Swaps Offered and Sold in Reliance on Securities Act of 1933 Rule 240”
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Geri Driscoll  Paul Josenhans  Sean Prince  Dave Yankee
George Fackler  Tom Keefe  Tom Kilkenny  Joe Renouf
Appendix D — Other Resources and Upcoming Events

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Events
Utility Industry Book/Tax Differences
Dallas, Texas | March 25, 2015
For more information, please contact: USEnergyTaxSeminars@deloitte.com.

Financial Reporting for Income Taxes: Rate-Regulated Utilities
Dallas, Texas | March 26, 2015
For more information, please contact: AlternativeEnergy@deloitte.com.

Deloitte Energy Conference
The Woodlands, Texas | September 29–30, 2015
For more information, please contact: EnergyConference@deloitte.com.

Power & Utilities Accounting, Financial Reporting and Tax Update
Chicago, Illinois | December 1, 2015
For more information, please contact: USEnergyFallSeminars@deloitte.com.

Energy Transacting: A View on Accounting and Valuation
Chicago, Illinois | December 2, 2015
For more information, please contact: USEnergyFallSeminars@deloitte.com.

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