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Power and Utilities

Accounting, Financial Reporting, and Tax Update

January 2017

Contents

Foreword

January 2017

To our clients, colleagues, and other friends:

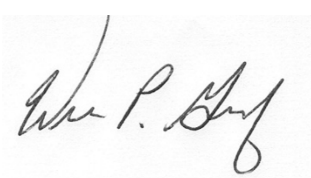
We are pleased to present our 15th annual Accounting, Financial Reporting, and Tax Update for the power and utilities (P&U) industry. More than ever, our industry continues to face changing markets, new legislation, environmental initiatives, regulatory pressures, cyber and physical threats, and new 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, and tax guidance, and focuses on specialized industry accounting topics that frequently affect P&U companies, including rate-regulated entities. We have expanded several sections in this year's publication that concentrate on accounting and reporting considerations related to the new leases and new revenue standards, including the discussion of those specific industry matters that remain outstanding with the AICPA's Power and Utility Entities Revenue Recognition Task Force.

Certain sections of this publication are designed to help you understand and address potential challenges in accounting and reporting related to topics on which the FASB has recently issued (1) proposed guidance or (2) final standards that are not yet effective or available for adoption. Our publication discusses such proposed and codified standards 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 A for additional information and assistance.

Sincerely,



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Section 1 — Industry Developments

Role of M&A in the P&U Sector

M&A activity in the energy sector continued to heat up in 2016, with many micro- and macroeconomic factors coming together to create an opportunistic environment. The micro- and macroeconomic factors are being driven by market volatility throughout the sector, which is attributable to low natural gas and wholesale power prices and a low interest rate environment. Compounding the market volatility is the movement away from traditional fossil-fuel-fired generation toward cleaner sources, coupled with changing energy market dynamics. Many regulated utilities have significant capital expenditure plans related to infrastructure needs that constitute growth potential for acquirers. All of these factors have led to shifting opportunities for energy investments by both public and private entities.

Consistent with predictions, this year saw a flood of generation assets coming up for sale. Declining equity valuations have driven publicly traded independent power producers to consider asset sales — even, in the case of Talen Energy Corp., a sale of the company. However, such a phenomenon is not limited to this market. New types of investors have been moving into the renewable energy space as a result of fundraising challenges that have greatly slowed the once-rapid pace of yieldco deals. The industry continues to see high premiums for the acquisitions, although not as high as in the previous year. Some examples of transactions completed and announced in 2016 include the following:

- Completed:
  - *July 2016 (announced August 2015)* — Southern Co. and AGL Resources Inc. (36 percent premium).
  - *July 2016 (announced March 2016)* — TransCanada Corp. and Columbia Pipeline Group Inc. (11 percent premium).
  - *September 2016 (announced February 2016)* — Dominion Resources Inc. and Questar Corp. (23 percent premium).
  - *October 2016 (announced October 2015)* — Duke Energy Corp. and Piedmont Natural Gas Co. Inc. (40 percent premium).
  - *October 2016 (announced February 2016)* — Fortis Inc. and ITC Holdings Corp. (14 percent premium; 33 percent premium to price before public announcement of a potential sale).
- Announced:
  - *May 2016* — Great Plains Energy Inc. and Westar Energy Inc. (13 percent premium).
  - *June 2016* — Riverstone Holdings Inc. and Talen Energy Corp. (17 percent premium; 56 percent premium to price before public announcement of a potential sale).
  - *September 2016* — Enbridge Inc. and Spectra Energy Corp. (11 percent premium).

M&A Activity

M&A continued to play an active role in the P&U sector in 2016. 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 expand 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.

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

- *TransCanada Corp. and Columbia Pipeline Group Inc.* — On July 1, 2016, TransCanada Corp. completed the acquisition of Columbia Pipeline Group Inc. The acquisition created one of the largest natural gas transmission companies in North America, with approximately 56,100 miles of gas pipelines, and 664 billion cubic feet (Bcf) of natural gas storage capacity.
- *Dominion Resources Inc. and Questar Corp.* — On September 16, 2016, Dominion Resources Inc. completed its acquisition of Questar Corp., which was first announced on February 1, 2016. The newly combined company includes 14,400 miles of natural gas gathering, storage, and transmission pipeline; approximately 51,000 miles of gas distribution pipeline; and more than a trillion cubic feet (Tcf) of natural gas storage capacity. In addition, it includes 6,500 miles of electric transmission lines, 57,300 miles of electric distribution lines, and 25,700 MW of electric production in 11 states.
- *Duke Energy Corp. and Piedmont Natural Gas Co. Inc.* — On October 3, 2016, Duke Energy completed its acquisition of Piedmont Natural Gas, nearly a year after it was announced on October 26, 2015. The acquisition adds 23,000 miles of gas distribution pipeline and 2,900 miles of gas transmission pipelines to Duke's portfolio.
- *Fortis Inc. and ITC Holdings Corp.* — On October 14, 2016, Fortis Inc. and GIC Private Limited acquired ITC Holdings Corp., a deal that was first announced on February 9, 2016. ITC was the largest electric independent transmission company in North America, serving a peak load in excess of 26,000 MW along approximately 15,700 miles of transmission line. Upon the completion of the acquisition, Fortis Inc.'s common shares began trading on the New York Stock Exchange.

Other significant M&A activity announced in 2016 includes the following:

- Calpine Corp. announced on October 9, 2016, that it had entered into an agreement to purchase Noble Americas Energy Solutions LLC (NAES) for $800 million plus an estimated $100 million in net working capital at closing. NAES is an independent retail electricity supplier to commercial and industrial customers in 18 states; its business model closely aligns with Calpine's concentration of wholesale power generation. Calpine is America's largest generator of electricity from natural gas and geothermal resources. This announcement came just a year after Calpine closed on its acquisition of Champion Energy Marketing LLC, another retail electricity supplier. The NAES deal is expected to close by the end of 2016, pending customary approvals.
- Enbridge Inc. announced on September 6, 2016, that it had reached an agreement to merge with Spectra Energy Corp. in a stock swap transaction valued at $28 billion. Spectra shareholders will get 0.984 shares of the combined company for each share held. This was equal to $40.33 per share, which represents an 11.5 percent premium to Spectra's closing price of $36.15 at the close of the previous business day (September 2, 2016). At the close of the transaction, Enbridge shareholders are expected to own approximately 57 percent of the combined company, which will keep the name Enbridge Inc. The deal is expected to close in the first quarter of 2017, after the appropriate shareholder and regulatory approvals are obtained, at which time the Spectra Energy common stock will be delisted from the New York Stock Exchange.

- Great Plains Energy Inc. announced on May 31, 2016, that it plans to acquire Westar Energy Inc. for $60 per share in a transaction valued at approximately $12.2 billion. Under the terms of the agreement, the $60 per share is a mix of approximately 85 percent cash ($51 per share) and 15 percent stock ($9 in Great Plains Energy common stock subject to a 7.5 percent collar based on the Great Plains Energy common stock price at the time of the closing of the transaction).

  Great Plains and Westar obtained shareholder approval for the merger at their respective annual shareholder meetings. However, additional approvals are still pending. In August 2016, the Kansas Corporation Commission allowed four new intervenors, for a total of 19. In addition, the Missouri Public Service Commission (PSC) has been trying to claim jurisdiction over the deal on the basis of an agreement from 2008 related to the acquisition of Aquila Inc. by Kansas City Power & Light, a subsidiary of Great Plains. The transaction also requires approval by FERC and the Nuclear Regulatory Commission (NRC).

- NextEra Energy Inc. announced on December 3, 2014, that it had entered into an agreement to acquire Hawaiian Electric Industries Inc. for approximately $4.3 billion. The acquisition was approved by FERC on March 27, 2015, and the required premerger waiting period under the Hart-Scott-Rodino Act expired on September 9, 2015. However, the deal was unable to secure final approval. On July 15, 2016, the Hawaii Public Utilities Commission (HPUC) rejected the proposed merger, noting that the benefits offered by the agreement, including rate credits for the customers, investment funds, and a rate-case moratorium, were both inadequate and uncertain. The Commission also said that the agreement did not offer sufficient protection to the Hawaiian Electric Industries and its ratepayers from the risks presented by NextEra's complex corporate structure. After reviewing the Commission's order, the two companies announced on July 18, 2016, the termination of their plans to merge. Under the terms of the agreement, NextEra was required to pay Hawaiian Electric Industries a $90 million break-up fee and up to $5 million for reimbursement of expenses associated with the transaction.

- On July 29, 2016, NextEra announced its agreement to acquire, through a newly formed subsidiary, 100 percent of the equity of Energy Future Holdings Corp. (EFH) and certain of EFH's direct and indirect subsidiaries, including EFH's approximately 80 percent indirect interest in Oncor Electric Delivery Co. LLC ("Oncor"), for a total value of $18.4 billion. This agreement was part of an overall plan of reorganization to allow EFH to emerge from Chapter 11 bankruptcy. A major step in that plan occurred on October 3, 2016, when the competitive businesses of EFH emerged from bankruptcy after the stock of Vistra Energy was issued to certain former creditors. The NextEra announcement came just months after Hunt Consolidated Inc. dropped its bid of $17 billion to buy out the 80 percent interest in Oncor and form a real estate investment trust because of conditions put on the approval by the Public Utility Commission of Texas (PUCT).

  In addition, on October 31, 2016, NextEra announced its proposed acquisition of Texas Transmission Holdings Corp (TTHC), including TTHC's approximately 20 percent interest in Oncor, for about $2.4 billion. The acquisition of TTHC's interest in Oncor would give NextEra 100 percent ownership of Oncor when combined with NextEra's acquisition of EFH's indirect interest in Oncor (discussed above) and the remaining 0.22 percent interest in Oncor that NextEra agreed to acquire from Oncor Management Investment LLC. With the announcement, NextEra proposed a ring-fenced structure, including a commitment to maintain (1) a separate board of directors for Oncor and (2) workforce stability and strong protections for Oncor employees.

  The proposed acquisitions of EFH and TTHC are subject to certain conditions, including confirmation of the EFH bankruptcy plan, approval from the PUCT of Texas, and receipt of an

IRS private letter ruling (PLR) affirming the tax-free nature of the EFH transaction. If the deals are approved, the combined company will have approximately 200,000 miles of power lines and 8.6 million electric service customers/delivery points.

- Liberty Utilities Co. (a subsidiary of Algonquin Power & Utilities Corp.) announced on February 9, 2016, that it will acquire the Empire District Electric Co. for $2.4 billion. Under the agreement, Empire's shareholders will receive $34 per common share in cash, which represents a 21 percent premium to the closing share price on February 8, 2016. The acquisition allows Algonquin Power & Utilities Corp. to expand its regulated utility footprint.

  Approvals were required from the shareholders as well as from FERC and multiple state commissions, including those of Arkansas, Kansas, Missouri, and Oklahoma. The acquisition was approved by Empire's shareholders on June 16, 2016, by the Missouri PSC on September 7, 2016, and by the Arkansas PSC on September 29, 2016. The remaining approvals are pending, and the transaction is expected to close in the first quarter of 2017.

- On June 3, 2016, Riverstone Holdings LLC announced its plans to acquire the remaining 65 percent of Talen Energy Corp. that it does not already own for $1.8 billion in cash plus assumed debt. The acquisition will give Talen Energy's shareholders $14 per share, which represents a 17 percent premium to the previous business day's closing price.

  The announcement came just a year after the formation of Talen Energy. On June 1, 2015, Talen Energy was formed when the power generation business of PPL Corp. was spun off and combined with the generation business owned by Riverstone Holdings, providing approximately 15,000 MW of generating capacity.

  On October 6, 2016, Talen's shareholders approved the acquisition, and applications for approval from FERC and the NRC are still pending.

- Tesla Motors Inc. announced on June 21, 2016, that it had reached an agreement to acquire SolarCity, in which SolarCity shareholders would receive 0.11 common shares of Tesla per common share of SolarCity, which at the time was equivalent to $22 per SolarCity common share. The announcement of the acquisition has come with some skepticism, including from analysts who do not believe that this acquisition is the best and highest use of Tesla's capital. On November 17, 2016, shareholders of both Tesla and SolarCity approved the merger, and the deal closed on November 21, 2016.

During 2016, as in 2015 and 2014, there was significant activity involving acquisitions of power plants and other assets. The following table lists some of the transactions that occurred in 2016 (dollar amounts in millions):

Date	Buyer	Seller	Base Value	Assets
9/14/2016	ArcLight Capital Partners LLC and The Blackstone Group LP	American Electric Power Co. Inc.	$2,170	1 coal-fired plant and 3 gas-fired plants
7/29/2016	Starwood Energy Group Global LLC	NextEra Energy Inc.	$760	2 gas-fired plants
6/20/2016	Florida Power & Light	Indiantown Cogeneration LP	$451	Cogeneration business
6/15/2016	Southern Power Co.	Invenergy Wake Wind Holding LLC	$469	U.S. wind business
5/12/2016	RA Generation LLC	Aurora Generating Station	$365	1 generation station
4/4/2016	Luminant Generation Co. LLC	La Frontera Ventures LLC (NextEra)	$1,313	2 gas-fired plants
2/25/2016	Atlas Power (Dynegy Inc. and Energy Capital Partners joint venture)	Engie SA, US Fossil Power Facilities	$3,300	Fossil-fuel-powered facilities
2/25/2016	Public Sector Pension Investment Board	Engie SA, US Hydro Power Facilities	$1,200	Hydroelectric assets portfolio
1/29/2016	Hydro One Inc.	Great Lakes Power Transmission	$222	Transmission portfolio

Ratemaking

Rate-Case Activity

The number of retail rate cases in the United States has approximated 100 in each of the last five calendar years. There were 98 electric and gas rate cases resolved in 2015, 99 in both 2014 and 2013, 111 in 2012, and 87 in 2011. Approximately 70 electric and gas rate cases were decided in the first nine months of 2016, and roughly 35 electric and gas rate cases were decided in the fourth quarter of 2016; this volume was lower than that of the past several years but still higher than that of the late 1990s and early 2000s. The elevated level of activity since the early 2000s is attributable to increased costs driven by environmental compliance, generation and delivery infrastructure upgrades and expansion, renewable generation mandates, and employee benefits, combined with slower growth in sales volumes.

In the first 10 months of 2016, the average authorized return-on-equity (ROE) percentages for electric utilities were relatively the same as they were in 2015, while those for gas utilities as set by regulators were slightly lower. For electric utilities, the average ROE percentage was approximately 9.87 percent in the first 10 months of 2016 (based on 27 cases) and approximately 9.85 percent in 2015 (based on 30 cases). For gas utilities, the average ROE percentage set by regulators was approximately 9.49 percent in the first 10 months of 2016 (based on 18 cases) and approximately 9.60 percent in 2015 (based on 16 cases). 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.

Separately, some states have decided to look into nontraditional rate-case models and have begun working on implementing these new regulatory frameworks. Two such frameworks are highlighted below.

Minnesota's e21 Initiative

In February 2014, Minnesota began a collaborative process to define the 21st Century Energy System ("e21") with the goal of identifying a new framework that will resolve the fundamental misalignment between the traditional utility model, technology advancements, and public policy goals. The new regulatory framework recommendations are related to performance-based ratemaking, customer option and rate design reforms, planning reforms, and regulatory process reforms. On the basis of Phase I, which was completed in December 2014, the following was noted:

- Utilities would operate in an environment that emphasizes providing services and options aligned with customer expectations (e.g., energy efficiency, renewables, distributed generation) instead of volume of electricity sold.
- The framework would require collaboration of all stakeholder entities and would leverage integrated resource analysis instead of an integrated resource plan.
- The framework would make it possible to meet all applicable policy goals and would ensure that utilities have a viable business model.
- The ratemaking process would change from a cost-of-service approach to a performance-based, forward-looking framework.

The participants in the e21 Initiative are currently focusing on e21's second phase, which was devoted to developing the next level of detail necessary for implementation of e21's Phase I recommendations.

Some industry observers believe that Minnesota (through the e21 Initiative) as well as the four other states focusing on "the utility of the future" could define new options for how the electric system is modernized and how the utility business model is structured.

In July 2016, E Source, a company that publishes reports on the energy industry's services and best practices, featured Minnesota's e21 initiative in an ongoing series of reports about the evolution of utility business models across the country.

New York's Initiative

In early 2015, the New York PSC issued an order attempting to revamp the state's utility business model, known as the Reforming the Energy Vision (REV) initiative. For more information about the REV initiative, refer to Electricity Storage in Section 1.

Future of Coal-Fired Generating Units

The future use of coal-fired generating units in the United States continues to evolve. Coal as an energy source faces a number of regulatory and market-imposed headwinds since coal-fired power plants remain viewed as environmentally unfriendly, as they are major CO_2 emitters. Market dynamics, including low prices of natural gas and the reduced demand for electricity, continue to affect the power plant generating mix across the country. In addition, regulators keep pressuring power plant owners, especially owners of plants that use fossil fuel to generate electricity, to further reduce emissions, all while state regulatory commissions mandate the increased usage of renewable power generation.

In the meantime, economic concerns are also mounting. One factor is the Mercury and Air Toxics Standards Act (MATS), which is increasing the cost of running coal-fired power plants through limits it places on the emissions of toxic air pollutants such as mercury, arsenic, and metals; it is discussed in greater detail below. In addition, major banks are receiving pressure to scale back coal financing[1] because of environmental concerns, increasing borrowing costs and further disadvantaging coal-fired generation and its attractiveness as an investment as compared with natural gas in the United States.

As a result of these factors, there remains a concerted effort to reduce the use of coal-fired generating units in the United States, as demonstrated by the fact that certain plants are set to be retired or converted to other fossil fuel sources such as natural gas or biomass over the next several years. Recent reports have indicated that companies have formalized plans to permanently shut down or convert more than 70 coal-fired generating units from 2017 through the end of 2026,[2] reducing the available capacity by approximately 12,500 MW and converting approximately 3,000 MW of existing capacity to other fossil fuel sources. In 2016 alone, close to 50 coal-fired generating units were either retired or converted, reducing the available capacity by approximately 4,800 MW and converting approximately 4,250 MW of capacity to other fossil fuel sources.

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 June 2016, there were 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.

Coal prices in the United States have also steadily declined in recent months. Forward prices for Central Appalachia for the forward 36-month period decreased by about 14 percent on average from the third quarter of 2015 to the third quarter of 2016. Forward prices for Powder River Basin for the forward 36-month period rebounded slightly and increased by roughly 5 percent on average from the third quarter of 2015 to the third quarter of 2016; however, prices are still generally down. Lower natural gas prices, combined with the increasing regulatory constraints that are causing power producers to gradually turn their attention from coal to natural-gas-fired generation capacity, have led to decreases in demand and reductions in price.

Clean Air Interstate Rule

In April 2005, the EPA issued the CAIR to regulate emissions of SO_2 and NO_X 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. The CAIR has been replaced by the Cross-State Air Pollution Rule (CSAPR) as of January 1, 2015.

Cross-State Air Pollution Rule

The EPA continued its efforts to curtail power plant emissions by issuing the CSAPR in July 2011. This rule set limits on emissions from power plants in 28 eastern states via a new cap-and-trade program. The

1 Source: http://www.nytimes.com/2016/03/21/business/dealbook/as-coals-future-grows-murkier-banks-pull-financing.html?_r=0.
2 Source: http://www.sourcewatch.org/index.php/Coal_plant_retirements.

intent of the rule is to improve air quality by reducing power plant emissions that may affect pollution in other states.

Although a federal appeals court vacated certain aspects of the CSAPR in August 2012, the U.S. Supreme Court ultimately ruled to uphold the CSAPR in April 2014. The Supreme Court's decision did not automatically reinstate the CSAPR; it simply remanded the case to the appeals court. On October 23, 2014, the appeals court approved the EPA's request to lift the stay of the CSAPR and delay the compliance deadlines by three years since the original compliance dates have passed.

The Supreme Court's decision to vacate the federal appeals court ruling in April 2014 did not mark the end of the ongoing legal battles since there were several other legal challenges to be considered by the appeals court. On January 15, 2015, the EPA formally filed a brief with the appeals court, refuting the merits of the remaining challenges. On July 28, 2015, while offering its opinion on the remaining issues, the appeals court upheld the rule. Consequently, the CSAPR remains in place.

On February 26, 2016, the EPA issued a ministerial action to align the dates in the final rule's text with the final implementation schedule. On September 7, 2016, the EPA issued a final update to the CSAPR to address the interstate air quality effects with respect to the 2008 ozone National Ambient Air Quality Standards (NAAQS).

The effective dates of the CSAPR requirements are staggered. As a result of the revised implementation timeline, the Phase 1 emissions budgets apply to 2015 and 2016, and the Phase 2 emissions budgets and assurance provisions apply to 2017 and beyond. Starting in May 2017, power plant NO_x emissions will be reduced during the summer months (i.e., May to September), reducing the effects on air quality of ozone pollution that travels across state lines. This will help enable states that are downwind from power plants to maintain the level of air quality required by the NAAQS.

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 plants, (2) reduce acid gas emissions from power plants by 88 percent, and (3) reduce SO_2 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 permitted, that plant is not allowed to operate. Under the MATS rule, reductions were to be achieved starting in the first quarter of 2015.

On June 29, 2015, however, the U.S. Supreme Court blocked the rule from taking effect, holding that the EPA had not properly considered cost estimate implications when drafting the rule. The case was remanded to the U.S. Court of Appeals for the District of Columbia Circuit. On December 15, 2015, the Court of Appeals issued a ruling allowing the EPA to move forward with enforcing the MATS requirements as the EPA considers the flaws identified by the Supreme Court ruling (i.e., potential cost burden). The MATS rule was effective as of April 6, 2016.

Although the MATS rule is in effect, the EPA and other stakeholders continue to consider the rule's relevance and implications. The EPA completed a supplemental analysis evaluating the rule's costs, issuing a final report on April 14, 2016, that reaffirmed that the significant benefits of reducing mercury and other toxic pollutant emissions outweigh the related additional costs. Further, the EPA continues to receive challenges to the rule, most recently evaluating two petitions and then denying them on August 23, 2016.

Clean Power Plan

The EPA's most recent legislation intended to reduce the toxic emissions from coal-fired power plants is the Clean Power Plan (CPP), which the agency initially proposed on June 2, 2014, and formally issued as a final rule on August 13, 2015. The CPP is a comprehensive plan that is designed to reduce existing emissions by fossil-fuel electric-generating-unit plants. Under the CPP, by 2030, carbon emissions within the power sector would be reduced by about 32 percent compared with 2005 levels (this marks an increased reduction compared with the 30 percent specified in the proposed rule). The CPP is also expected to reduce other particle pollution, as well as NO_X and SO_2 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 CO_2 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.

The final rule provided that by September 6, 2016, states must submit either (1) their final compliance plan or (2) an initial plan, followed by a final plan to be submitted by September 6, 2018. Although the final rule became effective on December 22, 2015, the U.S. Supreme Court ordered the EPA to halt enforcement of the plan on February 9, 2016. This stay is to remain in place until a lower court rules in the open lawsuits against the plan. Regardless of the Supreme Court's stay, as of July 2016, several states had started working toward meeting the CPP's requirements.

Thinking It Through

The February 9, 2016, Supreme Court decision was decided by a 5–4 vote that was split along party lines. This was the first time the Supreme Court had ever stayed a regulation before a judgment was made by the lower Court of Appeals. Given the current political divide and the outcome of the recent federal election, all financial decisions on the future of the CPP will most likely be deferred until the new president takes office.

Carbon Pollution Standards for New, Modified, and Reconstructed Power Plants

On August 3, 2015, the EPA issued its final rule establishing CO_2 emissions standards for new, modified, and reconstructed power plants. The guidelines would limit emissions in the following manner:

- *Newly constructed fossil-fuel-fired steam-generating units* — Emissions would be limited to 1,400 pounds of CO_2 per MWh.
- *Reconstructed and modified fossil-fuel-fired steam-generating units* — Emissions would be limited to:
    - 1,800 pounds of CO_2 per MWh for sources with heat input greater than 2,000 MMBtu/h.
    - 2,000 pounds of CO_2 per MWh for sources with heat input less than or equal to 2,000 MMBtu/h.
- *Newly constructed and reconstructed fossil-fuel-fired stationary combustion turbines* — Emissions would be limited to 1,000 pounds of CO_2 per MWh (or 1,030 pounds of CO_2 per MWh for base-load natural-gas-fired units).

The only fossil-fuel-fired power plants placed in service over the past few years that are capable of meeting these requirements are combined-cycle gas turbine generators. For existing coal-fired generating units to meet the new requirements, they would need to use technology such as carbon capture and storage to reduce emissions. The final rule became effective on October 23, 2015. Since the

EPA's issuance of its carbon pollution standards for new, modified, and reconstructed power plants, the agency has received five petitions challenging certain aspects of the standards. On April 29, 2016, after considering the merits, the EPA denied the submitted petitions.

Liquefied Natural Gas

Natural gas accounts for roughly a quarter of global energy demand. Liquefied natural gas (LNG), which is natural gas that has been cooled to a liquid state to facilitate storage and allow the fuel to be economically stored or transported over long distances, constitutes 9.8 percent of the natural gas used globally. The natural gas is condensed into a liquid at close to atmospheric pressure by cooling it to approximately –260°F. 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. In recent years, the growth in demand for LNG has been directly correlated with the increasing popularity of natural gas.

While the supply of LNG has grown faster than that of any other energy source, LNG's global market share growth has stalled since 2010. However, global LNG exports are expected to increase given the numerous export terminals that are under development. Specifically, LNG exports to the Asia-Pacific region are expected to increase because geographic and geologic restrictions make LNG the only viable source of gas in that area. Japan, South Korea, and Taiwan rely on LNG to meet nearly 100 percent of their natural gas demand.

The United States has historically been a net importer of LNG through regasification facilities located on the East and Gulf Coasts given the price differential between domestic and international markets. The development of these facilities was supported by the $12 per MMBtu natural gas price in 2008. However, given the prices of $2 to $5 per MMBtu for 2014 through 2016, along with the increased supply of shale gas, regasification facilities have begun to convert from regasification to liquefaction in anticipation of LNG export.

According to the U.S. Energy Information Administration's *Annual Energy Outlook 2016*, the United States is expected to become a net exporter of natural gas by 2018. LNG exports are expected to grow to 2.5 Tcf per year by 2020, 4.6 Tcf by 2025, and 6.7 Tcf by 2040.

Whether those projections will be met depends on domestic and global energy prices. The incentive to pursue the development of LNG export terminals will persist as long as the prices in international markets exceed domestic gas prices, plus LNG conversion and transportation costs.

The construction of natural-gas-fired generation stations associated with the expected retirement of coal-fired generation stations, coupled with the expected increase of exports, may place upward pressure on domestic gas prices.

The first export shipment of LNG from the continental United States occurred on February 24, 2016, from Cheniere Energy's Sabine Pass terminal in Louisiana. The terminal has a permitted LNG export capacity of 4.16 billion cubic feet per day (Bcf/d). Sabine Pass is permitted to construct LNG production plants, referred to as trains, two of which are operational.

Construction on Dominion Resources' Cove Point terminal in Maryland is nearing completion, with its first commercial export of LNG expected by the end of 2017. Cove Point has authorization to export 0.77 Bcf/d.

Other notable LNG export terminals under development include the following:

- Corpus Christi LNG, in Texas, another Cheniere project. The terminal is under construction and is scheduled to begin service in 2018, with total permitted capacity of 2.14 Bcf/d.
- Sempra Energy's Cameron LNG terminal, in Hackberry, Louisiana. It is under construction and is scheduled to begin service in 2018. Permitted capacity at this facility is 1.7 Bcf/d.
- Freeport LNG's terminal, in Texas. It has three trains under construction with permitted capacity of 1.8 Bcf/d. The first two trains are scheduled to begin service in 2019, and the third is expected to come online in 2020.

The U.S. LNG export licensing process is administered by the 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. Several LNG producers are competing on cost, and some are considering entering into tolling arrangements to deliver LNG to international markets. FERC has approved or is evaluating the approval of the export of LNG from several other terminals, primarily along the Gulf Coast. However, the completion of all such facilities is considered unlikely given the uncertainty inherent in obtaining regulatory approvals and competing developments in other emerging markets, such as those in East Africa. Construction will also depend on successful financing of construction costs, which may exceed $10 billion for certain projects, and the successful execution of long-term capacity arrangements.

Despite these trends in activity, the market for bilateral LNG forwards has remained very small. Broker-dealer markets for LNG have been slow to develop, and there are still no exchange-traded LNG contracts. Therefore, most companies would conclude that LNG is not readily convertible to cash (RCC). Companies with LNG transactions are encouraged to keep up to date with their RCC conclusions as the market continues to evolve. Further, with development of the LNG markets, companies will likely enter into new types of contracts. Since LNG can be shipped globally, companies are likely to structure long-term LNG shipping and natural gas supply contracts and may also need additional access to natural gas transportation and storage.

Cybersecurity

Emerging Threats

The most important cybersecurity event for the North American electric power industry in 2016 actually occurred in Ukraine on December 23, 2015 — but its reverberations have been growing ever since. On that day, a very well planned and coordinated cyberattack resulted in the loss of power for hundreds of thousands of people for a number of hours. This was the first documented case of loss of load as a result of a cyberattack.

A thorough report on the attack was published in March 2016 by the North American Electric Reliability Corporation's (NERC's) Electricity Information Sharing and Analysis Center and the SANS Institute. There has been a lot of discussion about the attack in the electric power community, and the event has already been cited in at least one FERC order. While there is debate regarding how easy it would be to carry out such an attack in the United States, there is general agreement that a number of the vulnerabilities exploited by the Ukraine attackers are also present in electric-grid entities in the United States.

Regulatory Requirements

The NERC Critical Infrastructure Protection (CIP) cybersecurity standards for the electric power industry have continued to grow in importance, resulting in significantly increased investments required for NERC entities to help ensure compliance with the CIP standards. This trend shows no signs of diminishing anytime soon. There were three major developments in NERC CIP in 2016:

- On January 21, FERC issued Order 822. The order approved the standards that constitute CIP version 6 but also requested some changes. Probably the most significant of these is expanding the CIP requirements so they address virtualization — server, switch, storage, and desktop. As required, NERC chose a standards drafting team to propose these changes and submit them to the NERC membership for a vote by written ballot. This work is ongoing and will result in revised standards that will constitute CIP version 7.
- On July 1, the standards in CIP versions 5 and 6 came into effect, although some of the requirements have delayed enforcement dates. The industry had put an unprecedented effort into coming into compliance with these standards, although many questions regarding application and interpretation remain unanswered.
- On July 21, FERC issued Order 829, which mandated that NERC develop a CIP standard or standards for the cybersecurity of supply chains. FERC had indicated that it was considering such a mandate in its Notice of Proposed Rulemaking (NOPR) of July 2015 and had conducted a technical conference on the proposal in January 2016. However, some observers were surprised that FERC ordered sweeping mandatory standards. In addition, these standards require a short time frame for development: one year from the order's effective date (in October 2017). NERC has chosen a new standards drafting team for this effort, and the team is now at work. Depending on how the new standards are written, it is possible that they will require almost as much compliance effort as do the existing CIP standards.

Increased Focus on Cybersecurity Auditing

While P&U entities' focus has historically been on implementing first and second lines of cybersecurity defense, most companies are now investing in building or enhancing the third line of cybersecurity defense — independent cybersecurity audits. Those who are charged with corporate governance, including senior executives and boards of directors, are seeking additional assurance about the state of cybersecurity within the organization. They expect the organization to develop and deploy a holistic strategy for cybersecurity audits.

Other stakeholders are also getting into the game. Most external audit firms are beginning to include additional cybersecurity procedures as part of their financial statement auditing so that they can determine whether breaches occurred and, if so, whether there is any effect on financial statements. Federal legislation has been proposed to amend SEC financial reporting requirements to include cybersecurity risks, and the AICPA has released exposure drafts of the new emerging cybersecurity examination requirements. Regulatory bodies in other industries, such as financial services, are also beginning to require cybersecurity auditing.

Leading practice organizations are addressing these various demands for cybersecurity audits by engaging P&U entities' internal auditing groups in the development of cybersecurity auditing strategies, programs, and tools, as well as by enhancing internal skill sets and resources that focus on these activities.

Physical Security

Project 2014-04, *Physical Security*

In April 2013, Pacific Gas and Electric Co. (PG&E) experienced a physical security event at its 500kV Metcalf Substation in which attackers proceeded to (1) cut local AT&T fibers serving the substation and (2) shoot transformers within the substation to make them unusable. At the time, the grid was not under stress; however, California Independent System Operator (CAISO) took the precaution of issuing a Flex Alert asking local residents of Silicon Valley to conserve power. The event's impact prompted FERC to issue an order under Docket No. RD14-6-00 that mandated the creation of transmission substation physical security standards. Specifically, the Commission directed NERC, the FERC-certified Electric Reliability Organization, to propose new reliability standards.

NERC responded by creating Project 2014-04, which addresses physical security risks and vulnerabilities related to the reliable operation of the bulk-power system (BPS). This project resulted in the development of NERC standard CIP-014-1. Based on FERC's mandate, the standard was approved by NERC's board of trustees on May 13, 2014. On November 20, 2014, FERC issued Order 802, which approved CIP-014-1 but directed NERC to remove the term "widespread" from the standard. In response, NERC created CIP-014-2, which was approved by NERC's board of trustees on May 7, 2015.

Grid Assurance LLC

The Edison Electric Institute (EEI) in 2006 created a program requiring participants to have a certain number of spare transformers, which they then could agree to share with other utilities if a U.S. president were to declare an emergency following a terrorist attack.

A group of P&U companies partnered to create a more comprehensive program than the one offered by EEI. As a result, Grid Assurance LLC was formed to handle virtually all of their spare transformer equipment requirements.

Participation in Grid Assurance LLC is open to all energy entities on a subscription basis. The fee is cost based, which facilitates the subscribers' ability to recover such expenses. In accordance with a subscriber agreement, Grid Assurance LLC (1) maintains an inventory of critical spare transformers, circuit breakers, and related transmission equipment; (2) provides secure domestic warehousing of the inventory of spares in strategic locations; and (3) releases spare equipment to utility subscribers in the aftermath of catastrophic events.

In June 2015, the founders of Grid Assurance LLC asked FERC to acknowledge the benefits of energy entities' participation in the company. The request was to confirm that contracting with Grid Assurance LLC was an acceptable element of a mandatory critical infrastructure standard that requires entities to have a physical security plan and access to spare parts.

On August 7, 2015, FERC approved only part of the proposal since a rate filing under Section 2015 of the Federal Power Act had not been submitted and FERC therefore could not determine whether costs incurred under the subscription service will be just and reasonable. FERC agreed that contracting with Grid Assurance LLC for access to spare critical transmission equipment is a "permissible resiliency element of a physical security plan," although transmission owners that contract with Grid Assurance LLC remain subject to all applicable mandatory reliability standards. In addition, FERC agreed that sales by or purchases from Grid Assurance LLC of spare transmission equipment that is not in service at the time of the transfer do not require FERC's approval.

On December 4, 2015, Grid Assurance LLC filed a new petition (EL16-20) asking FERC to make certain further confirmations. FERC was asked to confirm the following:

- Contracting with Grid Assurance LLC and purchasing spare equipment from it after a qualifying event would be considered prudent.
- Subscribers may use single-issue ratemaking to seek recovery of the costs of purchasing the service and equipment.
- Grid Assurance LLC's service pricing plan (1) complies with FERC's affiliate pricing restrictions related to the purchase of nonpower goods or (2) is granted a waiver from FERC's affiliate pricing restrictions.

On March 25, 2016, FERC approved the above requests and granted a waiver from its affiliate pricing restrictions.

GridEx

On November 18–19, 2015, NERC's Electricity Information Sharing and Analysis Center (E-ISAC) held a two-day grid-security and incident-response tabletop exercise called GridEx III, in which hundreds of electric utilities as well as government agencies across North America participated. The exercise included fictional worst-case attack scenarios involving cyberattacks, drones, guns, and even bombs to cripple transmission and generation equipment and operations. In March 2016, NERC issued its public report outlining lessons learned from the exercise.

GridEX IV, held on November 14, 2016, was the fourth such exercise and included many additional organizations and registered participants. NERC is expected to issue a public report on the exercise's results.

Market Activity

Natural Gas

U.S. natural gas prices have remained depressed over the past year, despite a shift from coal to natural gas. Henry Hub spot prices increased slightly from $2.57 per MMBtu on September 30, 2015, to $2.98 per MMBtu as of September 30, 2016, but forward prices for the forward 36-month period decreased during this time by about 2 percent on average. This is the result of substantial increases in supply without a corresponding increase in demand. Supply increases are coming from improved drilling efficiency and new wells coming online as natural gas producers, particularly in the Marcellus Shale region, have been able to extract massively greater amounts of gas than had been expected. This further supports the expectation that supply is unlikely to be challenged even if a harsh winter drives increases in seasonal demand.

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 surplus 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 require updated analysis and can make it challenging to ensure that current market conditions have been appropriately reflected.

For more on industry developments regarding coal and liquefied natural gas, see Future of Coal-Fired Generating Units and Liquefied Natural Gas above.

Electricity

U.S. electricity prices also decreased from September 2015 to September 2016, as reflected in an analysis of prices charged by various regional transmission organizations (RTOs) across the country, including PJM Western Hub, ISO-NE Internal Hub, and ERCOT-North Zone. Forward prices for the forward 36-month period decreased by 9 percent on average from September 2015 to September 2016. The decrease in the price of power has been largely driven by the decrease in the price of natural gas and coal used to fuel generation facilities. The one exception is CAISO, whose power prices actually increased by 5 percent for the forward 36-month period. The state of California has passed legislation that requires significant amounts of renewable power generation to be sourced entirely within the state. This requirement has driven up prices in California but not for the other major RTOs. Some power generation companies are seeing lower profits because of the decrease in electricity prices. Further, as cash flows from certain power plants decline, entities are being required to consider long-term asset impairments.

Natural Gas Liquids

Natural gas liquids continue to be treated as local commodities because of 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 readily convertible to cash (RCC). However, as midstream infrastructure improves in the medium term and commercially viable markets develop, RCC conclusions will need to be revisited.

The Future of Nuclear

A decade ago, the United States was thought to be starting a "nuclear renaissance," but the industry is now facing what could be a sustained decline in generating capacity. During the 1980s, 1990s, and 2000s, no new reactors were placed in service, but the industry was able to add capacity through uprates and boosting output. Now, however, the aging nuclear fleet is being challenged by market dynamics (i.e., low natural gas prices and renewable energy production) that threaten operations, even those of nuclear plants with extended operating licenses. As of September 19, 2016, there were 100 nuclear units operating in the United States, of which 81 have received license extensions and 12 have pending applications. This is down from the 112 units operating in 1990. Five units have provided notice to the NRC of their plan for future submittal of first license renewal applications, and four units have provided notice of their plan for future submittal of second license renewal applications. Exelon Corp. plans to apply for a second license extension for Peach Bottom Atomic Power Station, Units 2 and 3, in the third quarter of 2018, and Virginia Electric and Power Company plans to apply for a second license extension for Surry Power Station Units 1 and 2 in the first quarter of 2019.

Five plants have been retired in the past several years for various reasons:

- Duke Energy Corp.'s Crystal River Unit 3 in Florida.
- Edison International's San Onofre Nuclear Generation Station in California.
- Dominion Resources Inc.'s Kewaunee plant in Wisconsin.
- Entergy Corp.'s Vermont Yankee in Vermont.
- Omaha Public Power District's Fort Calhoun Nuclear Generating Station in Nebraska.

Industry insiders expect more retirements to come in the near future. For example, PG&E announced that it will not pursue license renewal at California's last nuclear plant, Diablo Canyon, and that it will close the plant in 2025. In 2015, Entergy Corp. announced the closure of its Pilgrim plant in Plymouth County, Massachusetts.

At the end of 2015, there were at least 12 nuclear units "at risk" for early retirement because of market conditions as identified by UBS, Moody's, and Fitch Ratings. There are only 1 newly commissioned unit and 4 new units on the horizon. The NRC is reviewing six applications for new reactors comprising 15 units.

Assuming current nuclear operating capacity online of 102,502 MW and announced additions, license renewals, rerates, and retirements, capacity will increase by 4,654 MW in 2020. But if the 12 "at-risk" nuclear units are retired, capacity will decrease to 96,573 MW by 2020.

The following table lists nuclear units identified by UBS, Moody's, or Fitch Ratings as being at risk of retirement as of September 15, 2015:

Power Plant Unit	Ultimate Parent	County/ State	ISO/ RTO	Operating Capacity (MW)	Capacity Factor (%)	Net Generation (MWh)	Identified By
Byron PWR 1	Exelon Corp.	Ogle/IL	PJM	1,207	93.41	9,879,902	UBS
Byron PWR 2	Exelon Corp.	Ogle/IL	PJM	1,177	90.91	9,372,479	UBS
Clinton Power Station BWR 1*	Exelon Corp.	De Witt/IL	MISO	1,078	96.07	9,071,711	Fitch Ratings, UBS
Davis-Besse PWR 1	FirstEnergy Corp.	Ottawa/OH	PJM	908	73.29	5,829,169	Moody's
James A. FitzPatrick BWR 1**	Entergy Corp.	Oswego/NY	NYISO	852	78.14	5,828,694	UBS
Nine Mile Point BWR 1	Multi-owned***	Oswego/NY	NYISO	637	97.51	5,442,125	Fitch Ratings
Palisades PWR 1	Entergy Corp.	Van Buren/MI	MISO	810	87.02	5,822,926	Fitch Ratings
Pilgrim BWR 1[†]	Entergy Corp.	Plymouth/MA	ISO-NE	683	96.37	5,769,154	Fitch Ratings
Quad Cities BWR 1*	Multi-owned[‡]	Rock Island/IL	PJM	908	102.69	8,168,258	Fitch Ratings, UBS
Quad Cities BWR 2*	Multi-owned [‡]	Rock Island/IL	PJM	911	90.45	7,218,246	Fitch Ratings, UBS
R.E. Ginna PWR 1	Multi-owned[§]	Wayne/NY	NYISO	583	91.25	4,662,495	Fitch Ratings
Three Mile Island PWR 1	Exelon Corp.	Dauphin/PA	PJM	829	100.90	7,327,645	Fitch Ratings

* On June 2, 2016, announced to retire June 1, 2017 (Clinton), and June 1, 2018 (Quad Cities).
** In August 2016, Exelon Corp. agreed to assume ownership and operation.
*** Exelon Corp., EDF Group, and Long Island Power Authority.
[†] On October 3, 2015, announced to retire no later than June 1, 2019.
[‡] Exelon Corp. and Berkshire Hathaway Energy.
[§] Exelon Corp. and EDF Group.
Source: SNL Energy

The nuclear units identified above, including Pilgrim, Quad Cities, and Clinton, have an aggregate capacity of 10,583 MW. Of these units, only two are rate regulated (Quad Cities BWR 1 and 2), and the remaining 10 are merchant plants. Fitch Ratings said in its January 7, 2015, report that regulated-unit retirements are caused by extended outages where the repair costs are high. In a June 2016 article, Fitch Ratings said that merchant plant closures are largely being driven by low natural gas prices and sluggish demand as well as the units' being vulnerable because of their high operating and capital costs.

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 recently licensed (one project), under construction (two projects), or for which companies applied for either a combined license that is currently under review (four projects) or 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.

Tennessee Valley Authority's Watts Bar Unit 2

In October 2015, the Tennessee Valley Authority (TVA) completed construction of its Watts Bar Unit 2 nuclear facility. On December 15, 2015, Watts Bar Unit 2 finished receiving the initial load of fuel into its core. Watts Bar Unit 2 is not a new nuclear reactor; the TVA started the project in 1973 but canceled construction in 1985 after spending $1.7 billion. For decades, the reactor lay dormant; in 2007, however, the TVA resumed the project.

In April 2012, the TVA board of directors approved continuing the construction of the unit. Unit 2 was officially licensed by the NRC on October 22, 2015. Not long after the TVA achieved 99 percent power output during testing, the plant experienced an oil fire at the switchyard, causing the unit to be taken off-line. Extensive repairs at the switchyard will occur before full commercial operations begin at Watts Bar 2. When Unit 2 goes into service, it will be the first reactor to come online in 20 years.

When initial construction of Unit 2 was canceled in 1985, the estimated cost of completing the reactor was $2.5 billion. Some 30 years later, the actual cost of completion has turned out to be $4.4 billion.

Other Nuclear Facilities

New nuclear facilities currently in development or under construction 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 Dalton Utilities. The estimated initial costs for Georgia Power's share of constructing Units 3 and 4 were $6.1 billion, with scheduled completion dates in 2016 and 2017, respectively. The most recent estimated costs filed with the Georgia PSC are more than $7.5 billion, with scheduled completion dates in 2019 and 2020, respectively.

  The Georgia PSC has approved construction monitoring reports covering the period through December 31, 2015, including construction capital costs incurred. In August 2016, Georgia Power filed a report with the Georgia PSC covering the period from January 1, 2016, through June 30, 2016.

- *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. The new units will be jointly owned, with 55 percent of the plant owned by the operator, SCANA Corporation, a subsidiary South Carolina Electric & Gas Co., and 45 percent owned by the South Carolina Public Service Authority (also known as Santee Cooper). The initial estimated costs for Units 2 and 3 were $6.3 billion, with scheduled completion dates in 2016 and 2019, respectively. In November 2016, the South Carolina PSC approved revised estimated total costs of $7.7 billion, and Units 2 and 3 are now expected to be completed in 2019 and 2020, respectively.

Nuclear Energy Subsidies

Nuclear generation is carbon free; however, the CPP does not give credit toward clean power goals for existing plants. The CPP indicates that nuclear is a key component of states' ability to meet their clean power goals but gives credit for uprates only for new equipment and construction of new nuclear facilities. Nuclear plants that have closed have been replaced by gas-powered generators, which increase greenhouse gas emissions and thus have a negative effect on the states' ability to meet their goals. Although no federal credit is given for existing nuclear plants, state subsidies are viewed as one way to incentivize plant operators to continue to run the carbon- and emission-free plants.

In the summer of 2016, Exelon Corp. and Entergy Corp. won subsidies totaling $500 million per year from the state of New York. The state's goal is to spur clean energy development to cut greenhouse gas emissions by 40 percent from 1990 levels by 2030 and 80 percent by 2050. New York's nuclear plants will play a key role in achieving this target. The subsidies were announced in response to Exelon's and Entergy's announcements that they would have to close certain of their plants in the state if they did not receive financial help; the funds were being championed by New York Governor Andrew Cuomo. These subsidies were a major factor in Exelon's decision to purchase the FitzPatrick unit from Entergy.

There is opposition to the subsidies, including from environmental groups and other energy companies that believe the incentives will detract from the development of solar- and wind-power generation. Opponents also believe that the subsidies are a bailout of dangerous, aging, and unprofitable plants that should close. A lawsuit was filed in federal district court in Manhattan on October 20, 2016, arguing that the state overstepped federal authority to regulate energy prices.

On December 7, 2016, Illinois Governor Bruce Rauner signed Senate Bill 2814, the Future Energy Jobs Bill. It will provide Exelon with up to $235 million of subsidies per year, which will allow the company to continue to operate its Quad Cities and Clinton Power Station plants. Exelon had announced in June 2016 its plans to close both of these plants.

Small Modular Reactors

In May 2016, the TVA submitted an early site permit application to the NRC for a potential small modular reactor (SMR) plant at its Clinch River location. This is the first application to build a plant by using such technology. SMRs generate 300 MW or less, whereas traditional nuclear units generate 1,000 MW and up. SMRs can be manufactured in a factory and assembled on-site, which helps combat the significant up-front capital costs and potential overruns historically associated with constructing traditional nuclear plants.

Some opponents are concerned that without achieving economies of scale, the SMRs will produce power that is more expensive than that produced by the traditional plants. Other concerns include the SMRs' safety and security.

Nuclear Waste

Companies with closed reactors are using decommissioning trust funds that were set aside for dismantling to instead build waste storage on-site since the federal government's promise to take highly radioactive spent fuel is still unfulfilled. This trend may raise some questions about the sufficiency of the funding levels.

Without an exemption, NRC rules do not permit the plant operators to take money from their decommissioning trust funds to pay for building the concrete pads and rows of concrete and steel casks where waste is stored after it is cooled in special storage pools. But the NRC has always granted exemptions from those rules when asked to do so.

During the nuclear plants' lives, ratepayers paid to set aside money to eventually dismantle reactors, remove their radioactive components, and restore the sites. It was not envisioned to pay for indefinite storage of spent fuel on the roughly 100 nuclear plant sites throughout the United States.

The decommissioning trust fund usage has been necessitated by the failure to date of the DOE to open a permanent disposal site for spent nuclear fuel at Nevada's Yucca Mountain.

In the absence of a permanent disposal site, plant owners have resorted to redesigning the racks in their spent fuel pools to accommodate more of the waste and expand into "dry cask" storage. The spent fuel bottleneck leaves closed and soon-to-close nuclear plants with the prospect that for the indefinite future, they will be storing radioactive spent fuel on-site, where it is required to be guarded 24 hours a day, seven days a week.

Net Metering

Many of the current rate structures are incompatible with the widespread adoption of distributed generation and present electric utilities with financial challenges. This incompatibility is most evident with net metering programs. In net metering, customers can sell to their electric utility excess electricity generated by their distributed generation systems, typically at the full retail electricity rate. This mechanism may allow some customers to zero-out their monthly bills and shift an added burden onto non-distributed-generation customers for paying electric utilities' fixed costs.

Regulators dealing with net metering include the following:

- *Arizona Corporation Commission (ACC)* — On August 11, 2016, the ACC ordered UniSource Energy Services to offer a solar credit option instead of net metering (NM) for rooftop solar customers. This decision, which could establish a precedent for other Arizona utilities, provides a possible substitute for NM. Under the solar credit option, customers will have the chance to obtain credits on a per-kWh basis for energy production from their solar systems, with the value of credits dropping in tranches as more customers take advantage of the program.

  On December 20, 2016, the ACC voted to end the current system of NM and approved a policy under which solar customers will be paid an "export rate." This rate is expected to be based initially on cost of power from utility-scale solar farms until cost studies are developed by utilities on the basis of an avoided-cost method. The export rate will be set separately for each utility as part of the normal rate-case process, and it is expected to be much lower than the corresponding utility's retail rate.

  Existing solar customers whose systems are connected to the grid before their utility's rate case will be grandfathered into the existing NM program, but the December 20 decision said that the grandfathering of NM rates will be limited to a 20-year period.

- *California Public Utility Commission (CPUC)* — On January 28, 2016, the CPUC approved and adopted a NM successor tariff as the original NM tariff was about to expire. The purpose of the successor tariff was to continue the existing NM structure while making adjustments to align the costs of NM successor customers more closely with those of non-NM customers.

The successor tariff includes the following provisions:

- NM will continue through 2019.
- NM eligibility is extended to systems of up to 1 MW, provided that the interconnecting customer pays all study and grid upgrade costs.
- Utilities can charge a reasonable interconnection fee to cover certain types of costs (e.g., administrative costs, installation and inspection costs).
- NM successor customers will pay non-bypassable charges on each kWh of electricity consumed instead of net volume to better align with volumetric charges paid by other utility customers (the non-bypassable charges are equivalent to approximately 2–3 cents per kWh).

- *Hawaii Public Utilities Commission (HPUC)* — In October 2015, the HPUC ordered the credit for new retail net-metered solar customers to be cut to a "grid-supply tariff" that is guaranteed for two years and is on average less than half of what the utilities had been paying to existing net metering customers. In a September 16, 2016, order, the HPUC required the Hawaiian Electric Companies to give all residential customers the option of applying for enrollment in a time-of-use (TOU) rate program. The TOU rates, which will be tiered to encourage customers to shift power usage out of peak periods, conceptually align with the cost of producing and distributing power over the course of a day but are limited to 5,000 customers under the two-year program.
- *Nevada Public Utility Commission (NPUC)* — In 2015, the NPUC approved a tariff structure that increased fixed charges and lowered compensation for excess generation for both new and existing solar customers. In February 2016, the NPUC denied a proposal to allow for a grandfathering provision that would let existing solar customers stay on original NM tariff schedules.

  On September 12, 2016, the First Judicial District Court of Nevada ruled against the NPUC, holding that the NPUC's decision not to offer a grandfathering provision for existing solar customers was set through an unlawful process. Days later, the NPUC reached a settlement to allow the grandfathering of approximately 32,000 rooftop solar customers under original NM rates. Subsequently, the Nevada governor's New Energy Industry Task Force recommended a return to "full" retail NM, as long as a minimum charge is assessed to solar customers.

  In December 2016, the NPUC voted to restore retail NM rates to Sierra Pacific Power's service territory. Approved as part of Sierra Pacific Power's general rate case, the ruling will open up to 6 MW for rooftop solar in northern Nevada effective January 1, 2017, which will fall under original NM rates. While this ruling affects a relatively small number of customers in Nevada, it represents a fundamental departure from the 2015 decision.
- *Mississippi Public Service Commission (MPSC)* — On December 3, 2015, the MPSC unanimously voted to adopt a net metering policy. The policy includes a "two-channel" billing system, with one channel billed at the retail rate and the other channel (excess energy) valued and credited to customers' accounts at an avoided-cost rate. Customers' bill credits will have unlimited carryover. In addition, the net metering policy allows third-party ownership of rooftop solar systems, which will create opportunities for solar leasing businesses.

  In January 2016, the MPSC concluded that it would decline requests for rehearing on the previously adopted net metering policy.

EEI identified the increasing effect of distributed generation and associated net metering policies on the grid as a key issue for the electric utility sector. As illustrated above, 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. Net metering remains a divisive issue in many states.

Electricity Storage

The electricity system in the United States may be on the cusp of a period of more rapid change than at any time in the past 25 years or more. Pointing to a very different landscape are (1) the rising role of renewable generation, (2) tightening emission limits on fossil-fuel-based generation, (3) the acceleration of smart-grid deployment, and (4) the emergence of multiple options for electricity consumers to better manage overall consumption and the shape of their load. One important barrier to allowing these developments to achieve their full potential has always been the absence of economic and reliable electricity storage solutions. But there has recently been an acceleration in research and development of various forms of electricity storage, which offer the promise of more economic deployment at scale in the near term, bringing load-shifting and electricity reliability within reach of more and more utilities and consumers.

There are a number of applications for which energy storage solutions can usefully be deployed. Some technologies are uniquely suited to specific applications, whereas others can be more broadly used across a range of applications. Matching the application to the technology in a way that is both effective and economical will be a key success factor in increasing the market presence of energy storage technologies.

The acceleration of new technologies, changing consumer expectations and behaviors, and the structural evolution of the electricity generation and delivery system over the past decade are providing fertile ground for the emergence of maturing electricity storage technologies as key components of the new landscape in electric power. Wider deployment of electricity storage can benefit utilities by improving grid performance and reliability, allowing the avoidance of investment in peaking generation capacity and increased integration of renewable power into the grid. On the consumer side, electricity storage can enhance local, distributed generation by providing a load-matching capability under the control of the consumer, minimizing the need for net-metering arrangements. As solar rooftop installations grow, a natural complementary market for electricity storage is emerging, to be realized when consumers are convinced of the availability, reliability, and economics of storage.

Various states have passed energy storage legislation or launched initiatives to explore energy storage:

- *Arizona* — In May 2016, Tucson Electric Power, in partnership with E.ON Climate & Renewables and NextEra Energy Resources, received approval from the Arizona Corporation Commission to develop two 10-MW energy storage facilities in order to reduce its overall coal generation by more than 30 percent by 2030 through greater use of renewable power, energy efficiency, and natural-gas generation.
- *California* — In October 2013, the CPUC approved its proposed mandate that requires California's large investor-owned utilities to procure 1,325 MW of energy storage by 2020, with installations required no later than the end of 2024.

  In September 2016, California's legislature passed new bills that target energy storage. Bill AB 1637 increased funding by $249 million to the CPUC's Self-Generation Incentive Program, which offers financial incentives for the installation of distributed generation and energy storage. Bill AB 2868 directed the state's three investor-owned utilities to accelerate the deployment of energy storage with investments of up to 500 MW in addition to the 1,325-MW requirement established in 2013. Bill AB 33 directed the CPUC to analyze the potential for long-duration energy storage to increase grid integration of renewables.

- *Massachusetts* — In June 2015, Massachusetts launched a $10 million initiative to examine how energy storage can benefit the state and what regulatory changes would be needed to facilitate its growth. In April 2016, Governor Charlie Baker signed Bill H.4173. The law raised private and public net metering caps 3 percent each and preserved net metering for small solar systems and municipal solar projects. In August 2016, Governor Baker signed Bill H.4568, which directed the Department of Energy Resources (DOER) to decide whether it is prudent to set a target for electric companies to procure viable and cost-effective energy storage systems by a target date of January 1, 2020. In September 2016, the DOER recommended that 600 MW of advanced energy storage technologies be installed on the state grid by 2025.
- *New York* — In April 2014, Governor Andrew Cuomo and the New York PSC introduced the state's REV initiative. REV's goal is to drive regulatory changes that promote advances in the use of renewable energy sources, increases in energy efficiency, and wider deployment of distributed energy resources. Energy storage is an important component of REV, and technologies such as advanced batteries, ultracapacitors, fuel cells, and control modules could play a role in multiple aspects of REV-related projects and initiatives.
- *Oregon* — In June 2015, Governor Kate Brown signed House Bill 2193-B, which required certain electric companies to procure qualifying energy storage systems by January 1, 2020. An electric company may recover in rates all costs prudently incurred in the procurement of the energy storage system(s), including any above-market costs associated with procurement. Further, Senate Bill 1547, which Governor Brown signed in March 2016, is likely to boost demand for energy storage through an increase in Oregon's renewable portfolio standard to 50 percent by 2040.

Research firm GlobalData estimates that the global installed capacity of battery energy storage systems will increase to more than 14 GW by 2020, up from 1.5 GW in 2015. GlobalData says that increased renewable deployment has been stimulated by government initiatives, climate-change concerns, and a 50 percent drop in the price of battery energy storage systems.

In September 2016, Tesla announced that it was selected by Southern California Edison to build a 20-MW lithium-ion battery system at its Mira Loma substation, which will be one of the largest lithium-ion storage facilities when completed. Tesla also announced plans to double the size of its Gigafactory to meet production demand for both its electric vehicles and its utility-scale storage projects.

With regard to grid-scale energy storage projects, Indianapolis Power & Light Co. (IPL) and AES Corp. opened the 20-MW IPL Advancion Energy Storage Array Facility in July 2016. It is the first grid-scale, battery-based energy storage system in the MISO region. In addition, FERC hosted a technical conference on November 9, 2016, on methods to compensate energy storage systems for value provided in wholesale markets. This conference is viewed by analysts as the first key step taken by FERC to achieve grid integration of energy storage systems.

For more information, see the Deloitte Center for Energy Solutions' ***Electricity Storage: Tracking the Technologies That Will Transform the Power Sector***.

FERC Developments

Electric Industry Issues

Formula Rate Standards

Utilities establish most transmission rates by using a formula-based approach with rates updated annually. FERC requires utilities to share the annual rate updates with all interested parties and to file the updates with FERC on an informational basis.

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.

Annual updates to formula rates, including transmission rate incentives, must note the formula rate inputs related to each incentive, details on when FERC granted the incentives, and sufficient support to demonstrate that the input is consistent with the formula.

On March 19, 2015, FERC ordered six utilities to change their protocols regarding stakeholder participation in annual updates to their formula rates. The utilities were specifically ordered to modify their protocols to allow broader stakeholder participation in the annual rate update process and make supporting documentation more widely available and accessible.

FERC continues to focus on increasing transparency of formula rates. In December 2015, it launched an investigation into formula transmission rates charged by ISO New England Inc. (ISO-NE), stating that the associated tariff lacked adequate transparency and challenge procedures with regard to the region's transmission owners. In its order, FERC had the following findings about specific rates:

- The "rates lack adequate safeguards to ensure that the input data is correct and accurate, that calculations are performed consistently with the formula rate, and that the costs to be recovered in the formula rate are reasonable and prudently incurred."
- The "formula rates themselves lack sufficient detail to determine how certain costs are derived and recovered in the formula rates, and we have concerns involving the timing and synchronization between the [Regional Network Service] and [Local Network Service] formula rates" (footnote omitted).
- "The Commission's policy requires that all of the formula calculations be incorporated into rate schedules so that public utilities cannot unilaterally revise the calculations at their discretion. Further, formula rates must be stated with sufficient specificity, clarity, and transparency so as to be understandable and reviewable by those affected by them and by the Commission" (footnotes omitted).

Method for Determining Return on Equity

In a June 19, 2014, press release, FERC announced its adoption of a new discounted cash flow method "for determining the rate of [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 complaint involving the ROE of New England Transmission Owners (NETOs), as detailed in the Commission's Opinion 531. In the opinion, FERC established a paper hearing to give the participants in the matter "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 cut the base rate of the NETOs' ROE from 11.14 percent to 10.57 percent, finding that the existing rate was unjust and unreasonable. Also, it was determined that NETOs' maximum base ROE, including any incentives, cannot exceed 11.74 percent. In addition to the base ROE, the NETOs were previously granted in 2004 a 50-basis-point ROE premium applicable to legacy assets for being members of an RTO. The new base ROE became effective immediately, and FERC ordered the NETOs to provide refunds with interest for the period from October 1, 2011, through December 31, 2012. New transmission projects are also eligible for an additional ROE premium that is determined on a case-by-case basis.

Opinion 531-A constitutes FERC's ruling on only one of three complaints challenging the NETOs' base ROE, as reflected in ISO-NE'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 from December 27, 2012, to March 27, 2014.

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 was July 31, 2014.
- *EL14-12* — On October 16, 2014, FERC issued an order establishing "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. (MISO) transmission organizations to no more than 9.15 percent. This complaint also argued that the current ROE did not "reflect current capital market conditions."
- *ER15-945* — On March 31, 2015, FERC approved an ROE incentive of 50 basis points for ITC Midwest related to its being an independent transmission company. ITC Midwest had requested a 100-basis-point ROE adder. FERC acknowledged that it had historically granted 100-basis-point ROE adders to independent transmission companies but noted that these prior decisions were based on specific circumstances in each case.
- *EL12-39, EL13-63, EL14-90* — On August 12, 2015, a FERC administrative law judge (ALJ) certified an uncontested settlement resolving three complaints filed by Seminole Electric Cooperative Inc. and the Florida Municipal Power Agency challenging the ROE in Duke Energy Florida LLC's transmission formula rate. Under the settlement, Duke Energy Florida LLC's current ROE of 10.8 percent would decrease to 10 percent and cannot be changed until January 1, 2018, at the earliest. The ROE of 10.8 percent was established in 2007 as the result of a settlement between the utility and its customers. The uncontested settlement also required Duke Energy Florida LLC

to provide more than $14 million in refunds to its various network and point-to-point service customers.

- *EL13-48-001, EL15-27-000, and EL15-27-001* — In November 2015, utility subsidiaries of Pepco Holdings, together with regulators and public advocates from the District of Columbia, Maryland, Delaware, and New Jersey, filed a settlement with FERC to resolve pending complaints regarding the utilities' authorized base ROE. This settlement was approved by FERC on February 23, 2016, and allows a reduced 10 percent base ROE with a 50-basis-point adder to be applied to the base ROE in recognition of the utilities' RTO participation.
- *EL14-12* — In December 2015, a FERC ALJ recommended that the base ROE for transmission owners in MISO be reduced from 12.38 percent to 10.32 percent. This was in response to a complaint filed by several consumer groups in 2013. They argued that the ROE was excessive since it did not take into account changes in the marketplace since the ROE was established in 2003. The ALJ's recommendation cited the new, two-step discounted cash flow method adopted by FERC in Opinion 531 in 2014.
- *EL13-33-002 and EL14-86-000* — In March 2016, a FERC ALJ issued an initial decision finding that the prospective base ROE for transmission owners in ISO-NE should rise from 10.57 percent to 10.9 percent, with an overall ROE ceiling of 12.19 percent. The ALJ determined that the ROEs should be set halfway between the midpoint and the high end of the zone of reasonableness. This ruling was consistent with the earlier precedent set when the ISO-NE's base ROE was challenged.
- *EL14-12* — In September 2016, FERC affirmed the ALJ's decision to reduce the MISO ROE rate to 10.32 percent, effective immediately. The Commission's ruling, which addressed the EL14-12 issue discussed above, kept with the practice of setting the base ROE halfway between the midpoint and the top zone of reasonableness. FERC directed MISO to file tariff revisions that reflect a base ROE of 10.32 percent with an overall ROE ceiling of 11.35 percent. MISO and its transmission owners were ordered to return any excess revenues they collected, plus interest, for the 15-month period from November 13, 2013, through February 11, 2015.

Demand Response

In 2008, FERC adopted final rules requiring RTOs/ISOs to accept bids for demand-response resources in their markets for certain ancillary services. The final rules also permitted entities called aggregators to combine the demand-response activities of multiple retail consumers into RTO/ISO markets. In 2011, FERC adopted a final rule requiring RTOs/ISOs to pay demand-response resources the market price for energy when those resources have the capability to balance supply and demand and when dispatch of those resources is cost-effective. The rule also required RTOs/ISOs to establish a net benefits test to determine when demand-response resources are cost-effective.

On May 23, 2014, the D.C. Circuit vacated FERC's 2011 rule (Order 745) largely on jurisdictional grounds, requiring RTOs/ISOs to pay demand-response resources the market price for energy under certain circumstances. On January 15, 2015, FERC appealed the D.C. Circuit's decision to the U.S. Supreme Court. On May 4, 2015, the Supreme Court agreed to review the appeal during the court's October 2015 term. In agreeing to review the D.C. Circuit decision, the Supreme Court indicated that it would consider two specific questions: (1) whether FERC has the authority to regulate the pricing of demand response used by ISOs/RTOs and to recover those costs through wholesale rates and (2) whether the D.C. Circuit erred in holding that Order 745 was arbitrary and capricious.

On January 25, 2016, the Supreme Court upheld the rule, holding that FERC has the authority to require operators of organized energy markets to pay demand-response resources the market price for energy that they pay generators when certain conditions are met. The court ruled that "FERC has the authority — and, indeed, the duty — to ensure that rules or practices 'affecting' wholesale rates are just and reasonable." This ruling applies only to wholesale rates and not to retail rates. Finally, the court disagreed that Order 745 was arbitrary and capricious since FERC "provided a detailed explanation" of why it chose to set demand pricing the way it did.

Market-Based Rates

On June 19, 2014, FERC proposed changes to the market-based-rate-authority process. The proposed rule would, among other things, (1) clarify that when sellers can demonstrate that all of their generation capacity in a relevant market area is fully committed, they are not required to submit indicative screens as part of their horizontal market power analysis; (2) eliminate entirely the requirement for a seller to submit indicative screens if the seller is in an RTO market and relies on FERC-approved monitoring and mitigation to prevent the exercise of market power; and (3) require all long-term firm purchases of capacity and energy by market-based rate sellers to be reported in the sellers' indicative screens.

On October 15, 2015, FERC voted to approve the draft final rule for the market-based-rate-authority process. The order (Order 816) did not include the plan outlined in its notice of proposed rulemaking (NOPR) of June 2014 (RM14-14) to relieve market-based rate sellers in organized markets of their obligation to submit horizontal market power indicative screens. However, the order, which addressed a market-based rate filing submitted by the Public Service Co. of New Mexico to report on a change in status, was intended to provide guidance developed after numerous companies submitted applications raising the same issues.

The draft final rule was similar to the June 2014 NOPR in many respects. Specifically, the draft final rule would, among other things:

- Establish a 100-MW change in status threshold for reporting new affiliates.
- Require market-based rate applicants to report all of their long-term firm purchases of capacity and/or energy for which they have associated long-term firm transmission reservations.
- Retain a proposal to expand the default relevant geographic market for an independent power producer located in a generation-only balancing-authority area to also include the balancing-authority areas of each transmission provider with which the generation-only balancing-authority area is directly interconnected.
- Provide that (1) sellers do not need to report behind-the-meter generation in their indicative screens and asset appendixes and (2) behind-the-meter generation will not count toward the 100-MW change-in-status threshold or the 500-MW Category 1 seller threshold.

FERC rejected the request of the Public Service Co. of New Mexico for market-based rate authority in its home balancing-authority area because of certain deficiencies in the performance of the company's delivered price test (DPT) analysis and preparation of its simultaneous transmission import limit (SIL) study. In addition, FERC (1) offered guidance on the proper modeling and scaling of jointly owned generating plants in an SIL study, (2) outlined how entities should account for variable-fuel and O&M costs, and (3) clarified the type of transaction data that should be provided to corroborate the results of a DPT analysis.

On May 19, 2016, FERC issued Order 816-A, with the intent to provide clarification on Order 816. The order affirmed the determinations previously made and provided some clarification. Specifically, FERC did the following in Order 816-A:

- Denied a rehearing on the requirement to include the contract's expiration date when a seller claims that its capacity is fully committed.
- Clarified that the requirement for applicants to report all long-term firm energy and capacity purchases from generation capacity located within the RTO/ISO market if the generation is designated as a resource with capacity obligation does not apply if the generation is from a qualifying facility exempt from Section 205 of the Federal Power Act. FERC also affirmed that a market-based rate seller must list all its long-term firm power purchases in its asset appendix (Appendix B), even if it does not have market-based rate authority in its home balancing-authority area.
- Clarified that (1) Order 816 did not change the definition of long-term firm transmission reservations and (2) long-term firm transmission reservations are longer than 28 days.
- Affirmed the 100-MW threshold requirement and provided clarification on which markets would constitute a seller's relevant geographic market under the reporting requirement.
- Affirmed that sellers are not required to (1) include behind-the-meter generation in the 100-MW change in status threshold or the 500-MW Category 1 status threshold or (2) include such generation in the asset appendixes and indicative screens.
- Clarified that a hydropower licensee that otherwise sells power only at market-based rates will not be subject to the full requirement of the Uniform System of Accounts as a consequence of filing a cost-based reactive power tariff with the Commission.
- Granted an additional extension of time so that market-based applicants and sellers will not be required to comply with the corporate organizational chart requirement until the Commission issues an order at a later date.

In September 2016, FERC issued a Notice of Inquiry (NOI) into revising how it assesses market power in applications for market-based rate authority. The NOI requested comments on how the Commission can improve its single pivotal supplier analysis in its review of market-based rate applications, whether to precisely define "de minimis" in the context of the effect on competition, and whether to develop a specific test for determining whether a proposed transaction meets that definition.

Gas Industry Issues

Pipeline Investment

In April 2015, FERC formally approved a policy statement that encourages pipeline modernization by allowing interstate natural gas pipeline companies to recover certain capital expenditures made to pipeline system infrastructure via either a surcharge or a tracker mechanism. Under the policy statement, a pipeline company seeking such a mechanism has to meet five standards:

- Its pipeline would be required to have had a recent base rate case in some form.
- Costs would be limited to one-time capital costs incurred to meet specific safety or environmental regulations.
- Captive customers would be protected from cost shifting if the pipeline loses shippers or increases discounts to retain business.
- Periodic reviews would be required to ensure that the rates remain just and reasonable.
- It would be required to work with shippers to seek support for any surcharge.

In July 2015, FERC denied requests for clarification and declined to specify which data and procedures a pipeline company must provide to justify a surcharge or tracker. FERC intends the policy statement "to be sufficiently flexible so as not to require any specific form of compliance but to allow pipelines and their customers to reach reasonable accommodations based on the specific circumstances of their systems."

Gas Pipeline Rates

Historically, interstate pipeline companies had their rates examined by FERC only when they made requests for rate increases or if their rates were challenged by a customer in a formal complaint. This resulted in many pipeline companies' going for years without having their rates examined by FERC, leaving customers vulnerable to overcharges.

In September 2015, the Industrial Energy Consumers of America, along with a coalition of three dozen companies and organizations, asked FERC to resume mandatory three-year reviews of interstate natural gas pipeline rates.

In January 2016, FERC launched formal rate investigations into the costs and revenues of four pipeline companies (Tuscarora Gas Transmission Co., Empire Pipeline Inc. Iroquois Gas Transmission System LP, and Columbia Gulf Transmission LLC) to determine whether they were "substantially over-recovering their costs, resulting in unjust and unreasonable rates."[3] These four companies were chosen by FERC after a review of their 2013 and 2014 FERC Form 2 reports. Each had to file updated cost and revenue studies and participate in evidentiary hearings before a FERC ALJ.

In July 2016, settlements were filed at FERC for three (Tuscarora Gas Transmission, Empire Pipeline, and Columbia Gulf Transmission) of these formal Section 5 rate investigations. In the settlements, each company agreed to a rate reduction of some sort and agreed to file new rate cases with FERC at some point before 2022. Settlement discussions in the Iroquois case are ongoing.

Establishing ROEs

Historically, when FERC has reviewed incremental rates for expansions of existing pipeline systems, its policy has been to use the rate of return components approved in the pipeline company's last general rate case. However, since many pipeline rate cases result in settlements in which no ROE is specified, there are no comprehensive data on ROEs.

FERC uses the two-step discounted cash flow method in establishing a pipeline company's authorized ROE. This method incorporates short-term and long-term growth measures, and gross domestic product has been used by FERC as the long-term growth rate.

In two previous cases, FERC has approved an ROE of 10.55 percent for El Paso Natural Gas Co. and 11.55 percent for Kern River Gas Transmission Co.

Gas Storage

In October 2015, FERC issued Opinion 538, which contains detailed market power guidance for natural gas storage operators that propose charging market-based rates.

This decision was in response to an initial decision by a FERC ALJ in January 2014 that denied the request of ANR Storage Co. to charge market-based rates for gas storage.

The opinion states that "[t]his is the first fully-litigated proceeding where a gas storage provider has sought market-based rate authority. This case therefore presents an opportunity for the Commission

[3] Quoted from FERC's January 21, 2016, news release.

to set forth in detail its policies and procedures for market-based rate applications from gas storage providers, and allows the Commission to make clear how gas storage providers may meet the evidentiary burden they possess to demonstrate they lack significant market power."

Upon review of the ALJ's decision and further consideration of ANR's market power analysis (which included competing firm gas storage service, local production, and intrastate storage), FERC agreed with the ALJ's initial conclusion and found that ANR should not be permitted to charge market-based rates for gas storage.

FERC Policy on Mergers and Acquisitions

In May 2016, FERC issued a policy statement that clarified the hold harmless commitments offered by applicants to mitigate adverse rate effects from merger proposals. While applicants still have to demonstrate that the transaction would not have an adverse effect on rates, FERC declined to require hold harmless commitments to be of unlimited duration. In addition, FERC clarified the scope and definition of costs that should be subject to hold harmless commitments, identified the types of controls and procedures that applicants offering hold harmless commitments should implement, and clarified that applicants may be able to demonstrate that a transaction will not have an adverse effect on rates even if they do not offer a hold harmless commitment.

FERC Enforcement

In November 2016, the FERC Office of Enforcement (OE) issued the 2016 edition of its report on enforcement (the "2016 Report"). Updated annually since 2007, the enforcement report provides greater transparency into the Commission's enforcement activities and a breakdown of OE efforts for the year. It contains statistics and other details related to the investigation, auditing, and monitoring of entity activities under FERC's jurisdiction, including information about (1) the conduct of companies and individuals in wholesale natural gas and electricity markets and (2) the Commission's monitoring and use of data that entities provide to satisfy the myriad of FERC-mandated market and operations reporting requirements.

The 2016 Report notes that in fiscal year 2016, the OE will continue to focus on its priorities of the past few years:

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

The OE continues to view conduct involving fraud and market manipulation as a "significant threat to the markets the Commission oversees" and believes that "intentional misconduct undermines the Commission's goal of ensuring provision of efficient energy services at a reasonable cost, because the losses imposed by fraud and manipulation are ultimately passed on to consumers." This view is reflected in the OE's enforcement priorities and actions: the majority of investigations initiated by FERC focus on activities that may indicate manipulation in the markets.

2016 Common Audit Findings

Below are some of the areas in which the OE's Division of Audits and Accounting (DAA) has identified consistent patterns of noncompliance over the past several years (quoted material is from the 2016 Report, with footnotes omitted):

> **Formula Rate Matters.** Compliance with the Commission's accounting and the FERC Form No. 1 regulations for costs that are included in formula rate recovery mechanisms used to determine billings to wholesale customers continues to be a focal point of DAA's formula rate audits. DAA notes that certain areas of noncompliance could have been avoided had there been more effective coordination between the jurisdictional entity's accounting and rate staff to prevent the recovery of costs that should be excluded from the formula rate. Additionally, formula rate audits in recent years have observed certain patterns of noncompliance in the following areas:
>
> - Transmission vs. Distribution Plant — Utilities have included plant balances related to their distribution function in transmission formula rates. This has occurred when a distribution capital project is placed in service, and the appropriate policies and controls are not utilized to ensure that those project costs are classified as distribution plant and that the related depreciation is appropriately classified.
> - Tax Prepayments — Utilities have incorrectly recorded income tax overpayments for which they elect to receive a refund, and not apply to a future tax year's obligation, as a prepayment in Account 165, Prepayments. Including these overpayments in Account 165 has led to excess recoveries through formula rate billings. These costs are properly recorded in Account 146, Accounts Receivable from Associated Companies, or Account 143, Other Accounts Receivable, as appropriate.
> - Internal Merger Costs — Utilities have included merger-related costs in rates without Commission approval that are typically related to internal labor, severance, and integration costs. In these cases, utilities are subject to hold-harmless commitments to exclude merger-related costs from rates unless the Commission approves recovery of such costs. Utilities must have appropriate controls and procedures to ensure that merger-related costs are tracked and excluded from formula rates.
> - Merger Goodwill — Utilities have included goodwill in the equity component of the capital structure without Commission approval. It is the Commission's long-standing policy that goodwill should be excluded from rates.
> - Depreciation Rates — Utilities have used state-approved depreciation rates or a blended depreciation rate in their formula rate recovery mechanisms, rather than the depreciation rates approved by the Commission.
> - Asset Retirement Obligation (ARO) — Utilities have included ARO amounts in formula rates without explicit Commission approval. This includes the asset component that increases rate base, the depreciation expense related to the asset, the accretion expense related to the liability, and associated deferred taxes.
> - Allocated Labor — Utilities have charged labor costs to transmission projects without using an appropriate cost allocation method or time tracking. Specifically, DAA observed that controls were not sufficient to ensure that labor costs charged were appropriately allocated between transmission and distribution capital projects when employees worked on both, resulting in an inappropriate or unsupported allocation of labor costs charged to transmission projects.
> - Administrative and General (A&G) Expenses — Utilities have recorded nonoperating expenses and functional operating and maintenance expenses in A&G expense accounts, leading to an inappropriate inclusion of such costs in the formula rates.
> - Unused Inventory and Equipment — Utilities have included 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.
>
> **Open Access Transmission Tariffs (OATT).** 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, as DAA identified noncompliance with the OATT's terms and conditions. Specifically, DAA identified issues related to: improper use of network transmission service, improper sales from designated network resources, transmission capacity not released in accordance with Commission-approved tariffs, inaccurate available transmission capacity data posted on the Open

Access Same-Time Information System, and transmission service provided to customers under expired transmission service agreements.

Natural Gas Accounting and Tariff Matters. DAA continues to evaluate natural gas pipeline compliance with the Commission's accounting and the FERC Form No. 2 reporting requirements to ensure transparency and accuracy of data reported to the Commission. DAA's evaluations also continue to cover the administration and application of transportation services and rates among customers in accordance with the approved gas tariff. In recent comprehensive natural gas audits, DAA has observed noncompliance in the following areas:

- Gas Tariff Matters — Some natural gas pipelines did not comply with FERC gas tariff procedures. Specifically, they were not using the method specified in the tariff for valuing system gas activities, were not enforcing stipulations in Operational Balancing Agreements to manage and monitor gas imbalance activities between interstate and intrastate pipelines, were not updating reservation credit procedures for force majeure and non-force majeure events to be consistent with Docket No. RP11-1538-000, and were not reporting operational available capacity data consistent with North American Energy Standards Board requirements.
- Accounting and Reporting Matters — Some natural gas pipelines did not comply with Commission accounting requirements as they pertain to gas charges and activities, including: penalty revenues assessed to noncompliant shippers, transmission mains and compression station expenses, line pack inventory changes, shipper imbalances and cash-outs, lost and unaccounted-for gas, and fuel used in compressor stations. Other common accounting areas of noncompliance included derivation of allowance for funds used during construction; classification of non-operating activities associated with donations, fines and penalties, and lobbying activities; and capital project reimbursements and advances from customers. In regard to the FERC Form No. 2 reporting, there was some inaccurate or incomplete information for affiliate transactions and other subsidiary investment activities. Besides this, there were omissions and incomplete information from various schedules supporting the pipeline financial statements.
- Pipeline Integrity Management Costs — Certain natural gas pipelines have misclassified integrity management costs that are properly recorded as maintenance expenses. Commission accounting requirements, including accounting guidance in Docket No. AI05-1-000, provide that costs to develop integrity management programs, prepare pipelines for inspection, conduct pipeline assessments, and make repairs are to be charged to maintenance expense in the period the costs are incurred.
- Capacity Transparency and Allocation — Interstate natural gas pipelines are required to post available pipeline capacity on their web sites. These postings promote transparency of available pipeline capacity and enable greater competitive and efficient use of such capacity. Recent audits identified deficiencies in posting available pipeline capacity where quantities were omitted or incorrectly reported. The result is that some shippers may not be aware of or able to avail themselves of operational opportunities for use of available pipeline capacity.

Oil Pipeline (Page 700). An essential part of oil pipeline audits is an examination of the accounting and operating data included on page 700 of the FERC Form No. 6, Annual Cost of Service-Based Analysis Schedule. The information reported on page 700 could be used by the Commission and interested parties to evaluate interstate pipeline rates, among other uses. Recent oil pipeline audits have identified some accounting errors that impact the accuracy of amounts reported on page 700, including: intrastate amounts incorrectly included as interstate on page 700, misclassification of carrier property, charitable donations, fines/penalties, lobbying activities, and failure to use Commission-approved depreciation rates. DAA also identified . . . another company that did not use or charge correct rates for intermediate points in billings to customers and a company that inadvertently disclosed confidential shipper information in a filing made with the Commission.

Nuclear Decommissioning Trust Funds. The Commission's regulations concerning nuclear decommissioning trust funds require jurisdictional utilities owning nuclear power plants to file annual trust fund reports, among other requirements. Recent audit activity has identified utilities that have not satisfied the Commission's regulations by failing to: submit annual decommissioning trust fund reports, clearly distinguish Commission-jurisdictional monies from nonjurisdictional monies held in the trust funds, or accurately report the amount of Commission-jurisdictional money in the trusts.

Allowance for Funds Used During Construction (AFUDC). Recent audit activity has shown deficiencies in how jurisdictional entities have calculated AFUDC, resulting in excessive accruals of

AFUDC. Common findings during audits include: failure to exclude goodwill-related equity from the equity component of the AFUDC rate, failure to include short-term debt in computing the AFUDC rate, computing AFUDC on contract retention and other noncash accruals, compounding AFUDC more frequently than semi-annually, inclusion of unrealized gains and losses from other comprehensive income, and use of an AFUDC methodology not prescribed by the Commission in Order No. 561.

Consolidation. Commission accounting regulations require the equity method of accounting for all investments in subsidiaries. Recent audit activities continue to find jurisdictional companies incorrectly using the consolidation method of accounting for subsidiaries instead of the equity method. As a result, improper amounts were included in formula rate billings. Entities must seek a waiver from the Commission to use the consolidation method for an investment in a subsidiary.

Price Index Reporting and FERC Form No. 552 Reporting. DAA's recent energy-reporting audits have revealed common deficiencies that have led to unreported transactions to price indexes. Transactions that are unreported in price indexes lead to less robust price indexes and can impact prices published by indexes, particularly at illiquid hubs. Common deficiencies revealed during audits of the FERC Form No. 552 include: failures to disclose affiliate companies, improper transaction categorization, and inclusion of non-reportable transactions. These reporting errors on the FERC Form No. 552 hinder the usefulness and transparency of the form's contents.

Untimely Filing of Commission Reports. DAA identified instances in which companies have failed to file various reports with the Commission timely. These instances included decommissioning trust fund reports and required filings and reports related to mergers. Failure to timely file these reports immediately impacts the Commission's and industry's ability to use report-provided data. Untimely filing also negatively impacts the transparency of information and creates doubt regarding the effectiveness of these companies' compliance programs.

Record Retention. DAA has identified instances in which companies have failed to retain records in accordance with Commission regulations. In some cases, DAA determined that companies have failed to obtain records from the original owner when acquiring jurisdictional assets. DAA also identified instances in which inadequate records management programs led to premature destruction of records. Failure to maintain adequate records can impair the Commission's ratemaking and enforcement activities and ultimately impact an entity's ability to recover costs associated with those assets.

Section 2 — SEC Update

The SEC continues to focus on rulemaking, particularly in connection with its efforts to complete mandated actions under the Dodd-Frank Act and to implement provisions under the FAST Act. Key SEC rulemaking activities and other developments that have occurred since the last edition of this publication are discussed below.

SEC Rulemaking and Interpretive Guidance

SEC Reminds Registrants of Best Practices for Implementing New Revenue, Lease, and Credit Loss Accounting Standards

In recent speeches, the SEC staff has reminded registrants about best practices to follow in the periods leading up to the adoption of ASU 2014-09 (on revenue), ASU 2016-02 (on leases), and ASU 2016-13 (on credit losses). The staff's comments, which reiterated themes it has addressed over the past year, focused on internal control over financial reporting (ICFR), auditor independence, and disclosures related to implementation activities.

For more information, see Deloitte's September 22, 2016, *Financial Reporting Alert*.

SEC Requests Comments on Regulation S-K

In April 2016, the SEC issued a concept release that seeks feedback from constituents on modernizing certain business and financial disclosure requirements of Regulation S-K. The main requirements of Regulation S-K, which is the central repository for nonfinancial statement disclosure requirements for public companies, were established more than 30 years ago, and the modernization and optimization of these requirements may be called for as a result of evolving business models, new technology, and changing investor interests.

The release is part of the SEC's ongoing disclosure effectiveness initiative, which is a broad-based review of the Commission's disclosure, presentation, and delivery requirements for public companies. It follows the SEC's issuance last fall of a request for comment that sought feedback on the effectiveness of financial disclosure requirements in Regulation S-X that apply to certain entities other than the registrant.

For more information, see Deloitte's April 18, 2016, *Heads Up*.

SEC Requests Comments on Certain Regulation S-K Disclosure Requirements

In August 2016, the SEC published a request for comment (with an October 31, 2016, comment deadline) as part of its disclosure effectiveness initiative. The request for comment sought feedback on certain disclosure requirements in Subpart 400 of Regulation S-K related to management, certain security holders, and corporate governance matters. The Commission plans to take the comments received into account when it develops its study on Regulation S-K, which is required by the FAST Act.

For more information, see the press release on the SEC's Web site.

Non-GAAP Measures

Press coverage and SEC scrutiny of non-GAAP measures have resulted from the SEC's concerns about (1) the increased use and prominence of such measures, (2) their potential to be misleading, and (3) the progressively larger difference between the amounts reported for them and for GAAP measures. In a speech on June 27, 2016, SEC Chair Mary Jo White reiterated the SEC's concerns about practices that can result in misleading non-GAAP disclosures. She exhorted companies "to carefully consider [SEC guidance on this topic] and revisit their approach to non-GAAP disclosures." She also urged "that appropriate controls be considered and that audit committees carefully oversee their company's use of non-GAAP measures and disclosures."

In May 2016, the SEC staff issued new and updated C&DIs that clarify the SEC's guidance on non-GAAP measures. The updated guidance was intended to change certain practices about which the SEC has expressed concern. In remarks after the issuance of the C&DIs, the SEC staff strongly encouraged registrants to "self-correct" before the staff considers any further rulemaking or enforcement action related to non-GAAP measures.

For more information, see Deloitte's September 2016 *A Roadmap to Non-GAAP Financial Measures*; Deloitte's July 19, 2016, *Heads Up*; and Deloitte's *SEC Comment Letters — Including Industry Insights: What "Edgar" Told Us (Ninth Edition)* and the 2016 Supplement.

Thinking It Through

For the 12 months ended July 31, 2016, non-GAAP measures ranked second in the top-ten list of topics frequently commented on by the SEC's Division of Corporation Finance (the "Division") as part of its filing review process, moving up from fourth place for the comparable prior year. Over the next year, we expect the number of SEC comments to continue to remain high and even increase until the guidance in the updated C&DIs has been fully incorporated into practice. The SEC staff's most recent comment letters have particularly focused on the use and prominence of non-GAAP measures in press releases. Comments on press releases and filed documents have also centered on disclosures, including reconciliation requirements and the purpose and use of such measures. In addition, we expect to see more comments about the use of misleading measures, including measures that use individually tailored accounting principles, and the tax impact of non-GAAP adjustments.

SEC Proposes to Eliminate Outdated and Duplicative Disclosure Requirements

In July 2016, the SEC issued a proposed rule that would amend certain of the Commission's disclosure requirements that may be redundant, duplicative, or outdated, or may overlap with other SEC, U.S. GAAP, or IFRS disclosure requirements. The proposal also seeks comment on whether certain of the SEC's disclosure requirements that overlap with requirements under U.S. GAAP should be retained, modified, eliminated, or referred to the FASB for potential incorporation into U.S. GAAP.

The proposed amendments are the next step in the SEC's ongoing disclosure effectiveness initiative. As part of the initiative, the SEC in April 2016 also issued a concept release that sought feedback on modernizing certain business and financial disclosure requirements of Regulation S-K (see SEC Requests Comments on Regulation S-K above).

The comment period ended October 3, 2016. The SEC is assessing the comments it received.

Thinking It Through

The implications of the proposal are likely to vary depending on the category of change (e.g., duplicate, overlapping, superseded). The effect of some changes may not be significant if their purpose is only to eliminate a duplicated or superseded requirement. Changes to address overlapping requirements could have a more significant effect since they can result in what the SEC describes as (1) disclosure location considerations and (2) bright-line threshold considerations.

For more information, see Deloitte's July 18, 2016, *Heads Up* and the press release on the SEC's Web site.

SEC Staff Updates C&DIs

In September 2016, the Division issued the following C&DIs:

- *Question 139.33 and Question 126.41 related to Securities Act sections and forms* — Include guidance on self-directed "brokerage windows."
- *Question 301.03 related to Regulation AB* — Clarifies whether a funding-agreement-backed note with certain characteristics should be considered an "asset-backed security," as that term is defined in either Item 1101(c) of Regulation AB or Section 3(a)(79) of the Exchange Act.

In July 2016, the Division issued the following C&DIs:

- *Question 103.11 related to filing Schedules 13D and 13G (Rule 13d-1)* — Addresses whether a shareholder is exempt from filing Schedule 13G on the basis of the provisions in the Hart-Scott-Rodino Act.
- *Question 111.02 and Question 125.13 related to Securities Act sections and forms* — Contain questions related to an issuer's representation about the absence of a distribution of the securities received in an exchange.
- *Question 140.02 related to Regulation S-K* — Discusses how, in situations in which "a selling security holder is not a natural person," a registrant should "satisfy the obligation in Item 507 of Regulation S-K to disclose the nature of any position, office, or other material relationship that the selling security holder has had within the past three years with the registrant or any of its predecessors or affiliates."

In June 2016, the Division updated Section 271 of its C&DIs on rules related to the Securities Act. The updated guidance addresses questions about the completion of a merger transaction.

SEC Issues Final Rule to Improve Transparency of Certain Disclosures by Resource Extractors

In June 2016, the SEC issued a final rule in response to a mandate under Section 1504 of the Dodd-Frank Act, which requires issuers engaged in the commercial development of oil, natural gas, or minerals to disclose certain payments made to the U.S. federal government and to foreign governments. The rule is designed to improve transparency about payments related to resource extraction.

Under the rule, a resource extraction issuer must file with the SEC an annual report disclosing payments made to the U.S. federal government and to foreign governments that are:

- Made to further the commercial development of oil, natural gas, or minerals.

- Not de minimis.
- Consistent with the types of payments specified in the rule.

For more information, see Deloitte's June 30, 2016, journal entry.

SEC Proposes Amendments to the Definition of Smaller Reporting Company

In June 2016, the SEC issued a proposed rule that "would expand the number of companies that qualify as smaller reporting companies, thus qualifying for certain existing scaled disclosures provided in Regulation S-K and Regulation S-X." Specifically, the proposal would increase the qualification threshold from less than $75 million of public float to less than $250 million. Further, companies with public float of zero "would be permitted to provide scaled disclosures if [their] annual revenues are less than $100 million, as compared to the current threshold of less than $50 million in annual revenues."[1]

For more information, see Deloitte's June 29, 2016, journal entry.

Thinking It Through

The proposal does not change the $75 million public float threshold in the SEC's definition of "accelerated filer." Therefore, a company could qualify as a smaller reporting company and be eligible for the scaled disclosures but may also be an accelerated filer and subject to those requirements, including the shorter deadlines for periodic filings and the requirement to include an auditor's attestation report on ICFR.

SEC Releases Guidance Related to FAST Act

In January 2016, the SEC issued interim final rules and form amendments to implement certain provisions of the FAST Act. Among other aspects, the rules revise Forms S-1 and F-1 to permit an emerging growth company (EGC) to omit financial information from registration statements filed before an IPO (or confidentially submitted to the SEC for review) for historical periods required by Regulation S-X if the EGC reasonably believes that it will not be required to include these historical periods at the time the contemplated offering becomes effective. The rules and amendments became effective on January 19, 2016.

In addition, in December 2015, the SEC issued a number of C&DIs related to the FAST Act. Topics addressed in the C&DIs include (1) whether, and in what circumstances, an EGC can omit interim financial statements or financial statements of other entities from its registration statement and (2) FAST Act requirements that affect savings and loan holding companies.

See Deloitte's December 8, 2015, journal entry for more information about the FAST Act's effects on securities laws and regulations. Also see Deloitte's January 15, 2016, journal entry for further details on the interim final rules, as well as Deloitte's January 12, 2016, and December 18, 2015, journal entries for more information about the C&DIs.

[1] Quoted from the SEC's June 27, 2016, press release.

SEC Adopts Rules to Implement FAST Act and JOBS Act Provisions

In May 2016, the SEC issued a final rule that (1) marks the completion of the Commission's rulemaking mandates under the JOBS Act and (2) implements provisions of the FAST Act. Specifically, the final rule:

- Amends "Exchange Act Rules 12g-1 through 12g-4 and 12h-3 which govern the procedures relating to registration and termination of registration under Section 12(g), and suspension of reporting obligations under Section 15(d), to reflect the new thresholds established by the JOBS Act and the FAST Act."
- Applies "the definition of 'accredited investor' in Securities Act Rule 501(a) to determinations as to which record holders are accredited investors for purposes of Exchange Act Section 12(g)(1)."[2] The final rule also revises the definition of "held of record" and establishes a nonexclusive safe harbor under Exchange Act Section 12(g).

The final rule became effective on June 9, 2016.

In June 2016, the SEC issued an interim final rule that implements provisions mandated by the FAST Act. The interim final rule allows Form 10-K filers to provide a summary of business and financial information contained in the annual report. The rule indicates that "a registrant may, at its option, include a summary in its Form 10-K provided that each item in the summary includes a cross-reference by hyperlink to the material contained in the registrant's Form 10-K to which such item relates." In addition, the rule solicits comments on whether it should (1) include specific requirements or guidance related to the form and content of the summary and (2) be expanded to include other annual reporting forms. The interim final rule became effective on June 9, 2016.

For more information on the interim final rule, see Deloitte's June 2, 2016, journal entry and the press release on the SEC's Web site.

Thinking It Through

The SEC considered the interim final rule's effects on registrants and noted that the rule was not likely to significantly alter their current disclosure practices. SEC rules do not currently prohibit registrants from voluntarily including a summary in their Form 10-K; however, on the basis of the SEC staff's review of select Form 10-K filings, most do not include such a summary. Instead, the vast majority of registrants include a fully hyperlinked table of contents that allows users to easily navigate to corresponding disclosure items.

SEC Updates *Financial Reporting Manual*

In November2016, the Division updated its *Financial Reporting Manual* to clarify or add guidance on the following topics:

- *Paragraphs 1140.3 and 10220.7* — The number of years of a target company's financial statements that an EGC should present.
- *Paragraph 1330.5* — Filings required after Form 10 is effective.
- *Paragraph 5120.1* — Effect of loss of smaller-reporting-company status on accelerated-filer determination and filing due dates.
- *Paragraph 8110.2* — The May 2016 C&DI updates on non-GAAP financial measures.
- *Paragraph 10220.5* — EGC guidance on the financial statements of entities other than the registrant; pro forma information.

[2] Quoted from the SEC's May 3, 2016, press release.

- *Paragraph 11120.4, Index* — Implementation of the FASB's and IASB's new revenue standard.
- *Section 11200, Index* — Implementation of the FASB's and IASB's new leases standard.
- *Section 11300, Index* — Implementation of the FASB's new standard on disclosures about short-duration insurance contracts.

For more information, see Deloitte's November 22, 2016, journal entry.

In March 2016, the Division updated its *Financial Reporting Manual* to clarify or add guidance on the following topics:

- *Paragraph 2410.8* — Significance testing related to equity method investments.
- *Topic 10* — Requirements as a result of the FAST Act.
- *Topic 11* — Implementation of the FASB's and IASB's new revenue standard.

For more information, see Deloitte's March 22, 2016, journal entry.

Other SEC Matters

SEC Allows Inline XBRL Filing

In June 2016, the SEC issued an order that permits entities to use a format known as inline XBRL "to file structured financial statement data required in their annual and quarterly reports that is integrated within their HTML filings through March 2020." The SEC believes that use of inline XBRL will help "decrease filing preparation costs, improve the quality of structured data, and . . . increase the use of XBRL data by investors and other market participants."[3]

The Commission has also updated the EDGAR Filer Manual to accommodate the use of inline XBRL. Additional changes to EDGAR include the discontinued support for the 2014 GAAP financial reporting taxonomy, the 2012 COUNTRY taxonomy, the 2012 CURRENCY taxonomy, and the 2014 EXCH taxonomy.

FASB Issues ASU Rescinding Certain SEC Guidance

In May 2016, the FASB issued ASU 2016-11, which rescinds certain SEC guidance from the *FASB Accounting Standards Codification* in response to announcements made by the SEC staff at the EITF's March 3, 2016, meeting. Specifically, the ASU supersedes SEC observer comments on the topics below.

- Upon the adoption of ASU 2014-09:
  - Revenue and expense recognition for freight services in process (ASC 605-20-S99-2).
  - Accounting for shipping and handling fees and costs (ASC 605-45-S99-1).
  - Accounting for consideration given by a vendor to a customer (ASC 605-50-S99-1).
  - Accounting for gas-balancing arrangements (ASC 932-10-S99-5).
- Upon the adoption of ASU 2014-16, determining the nature of a host contract related to a hybrid financial instrument issued in the form of a share under ASC 815 (ASC 815-10-S99-3).

[3] Quoted from the SEC's June 13, 2016, press release.

SEC Announces Tool for Estimating Registration Fees

In April 2016, the SEC announced the launch of an online tool to help companies calculate registration fees for certain form submissions to its EDGAR Filer Manual. The tool is "intended to improve the accuracy of fee calculations and minimize the need for corrections." It "covers the most common filings companies use to register [IPOs], debt offerings, asset-backed securities, closed-end mutual funds, limited partnerships, and small business investment companies."[4]

SEC Approves 2016 U.S. GAAP Financial Reporting Taxonomy

In March 2016, the FASB announced that the SEC has approved the 2016 U.S. GAAP financial reporting taxonomy and has updated its EDGAR system to support the new version. The 2016 taxonomy reflects accounting standards issued during the past year as well as other corrections and improvements to the 2015 taxonomy. Changes include the (1) addition of new elements (i.e., XBRL tags), (2) deprecation or replacement of previously existing elements, and (3) modification of element definitions and other attributes.

For more information, see Deloitte's March 8, 2016, journal entry.

SEC Publishes Examination Priorities for 2016

In January 2016, the SEC's Office of Compliance Inspections and Examinations published its examination priorities for 2016. New priorities include liquidity controls, public pension advisers, product promotion, exchange-traded funds, and variable annuities. Further, the priorities "reflect a continuing focus on protecting investors in ongoing risk areas such as cybersecurity, microcap fraud, fee selection, and reverse churning."[5]

2016 AICPA Conference on Current SEC and PCAOB Developments

At the December 2016 AICPA Conference on Current SEC and PCAOB Developments, numerous speakers and discussion panels shared their insights into current accounting, reporting, and auditing practice issues. Key topics addressed at this year's event include the following:

- *New GAAP standards* — While the effective dates of the new GAAP standards vary, the message from the SEC, FASB, preparers, and auditors was clear: If you haven't started preparing for the adoption of these standards, it's time to do so. The SEC staff also reiterated its focus on disclosures that registrants provide about implementation of accounting standards in the years leading up to adoption, or what the veteran attendees fondly referred to as "SAB 74 disclosures." On this note, the staff particularly emphasized revenue recognition, noting that it expects to see more robust qualitative and quantitative disclosures about the anticipated impact of the new revenue standard, as well as about management's status in achieving implementation, in registrants' upcoming Form 10-K filings.
- *Non-GAAP measures* — Also top of mind was the ongoing dialogue related to disclosures about non-GAAP measures. Staff members from the Division indicated that they had seen notable improvement in the disclosures since the release of the SEC's updated C&DIs in May. However, SEC Chief Accountant Wesley Bricker noted there is still "more progress for companies to make, for example, in the evaluation of the appropriateness of the measure and its prominence, as well as the effectiveness of disclosure controls and procedures."

[4] Quoted from the SEC's April 18, 2016, press release.
[5] Quoted from the SEC's January 11, 2016, press release.

- *Continued SEC focus on disclosure effectiveness* — The SEC staff discussed its continued commitment to advancing its disclosure effectiveness initiative — a broad-based review of the disclosure, presentation, and delivery requirements in the SEC rules. The staff indicated that significant progress was made over the past year on projects related directly and indirectly to its disclosure effectiveness initiative. As part of the discussion, the staff commented on the SEC's ***Report on Modernization and Simplification of Regulation S-K***, which was issued in November 2016 pursuant to a mandate in the FAST Act. The report contains certain specific recommendations on ways to streamline and improve disclosures. Some of the most significant recommendations focus primarily on reduced burdens for preparers and enhanced readability of the financial statements as a whole.
- *ICFR* — Mr. Bricker emphasized the importance of ICFR and stated that the staff of the Office of the Chief Accountant (OCA) continues to encourage management, audit committees, and auditors to "engage in dialogue" on ICFR assessments. Whether ICFR and disclosure controls and procedures are related to new GAAP standards, non-GAAP measures, disclosure effectiveness, or any of the other issues addressed at the conference, it is clear that they are, and will continue to be, a key focus for regulators, preparers, auditors, and audit committees.

For more information, see Deloitte's December 12, 2016, ***Heads Up***.

Section 3 — Industry 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 construction work in progress (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 in customer rates sooner than would be required or permitted under general U.S. GAAP. Essentially, the regulator is providing current rates for a cost that is expected to be incurred in the future. As a result, if the regulator orders or agrees to an adjustment of this regulatory liability, there are no restrictions under U.S. GAAP 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 is permissible under U.S. GAAP, and the reversal of the regulatory liability 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 depreciation under U.S. GAAP, reversals of previously recorded excess reserves 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.

Further, 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 may conflict with the guidance in ASC 980-340 (discussed below) if negative depreciation was not a ratemaking method routinely used by the regulator before 1982.

Depreciation Reserve Transfers

Depreciation reserve transfers, which can be ordered by a regulator, result in the transfer of some amount of one class of property's accumulated depreciation to another class of property's accumulated depreciation. For example, a regulator may order that transmission accumulated depreciation be decreased by a stated amount and that generation accumulated depreciation be increased by that amount.

Such depreciation reserve transfers are not permissible under U.S. GAAP since U.S. GAAP guidance does not allow for "write-ups" of property in the absence of a reorganization or an acquisition accounted for as a purchase; under ASC 980-360 or ASC 360-10-35, there must be an impairment basis for any "write-downs" of property. If there is a change in a depreciation-related accounting estimate, the effect is reflected in the current and future periods as a prospective change and not through restatement or retrospectively adjusting amounts previously reported.

A reserve transfer can be viewed as a reduction in current-year depreciation expense for one category of plant and an increase in current-year depreciation expense for another category of plant. However, the amount of a reserve transfer could result in negative depreciation expense for a class of property since the amount of that transfer may exceed one year's depreciation expense for that class of assets. There is no basis in U.S. GAAP for reporting negative depreciation expense for an annual period since that would effectively result in writing up the asset.

If the amount of accumulated depreciation reduction ordered by a regulator exceeds the current year's depreciation expense for a class of property, such excess would normally result in a difference between the regulatory basis of accounting and U.S. GAAP.

Further, "deferral" of depreciation expense for major and newly completed plants is an indication of a possible phase-in plan and would need to be addressed accordingly.

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 effect of regulatory lag, a utility must use significant judgment and evaluate the specific facts and circumstances.

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. Recognized subsequent events provide additional evidence about conditions that existed as of the balance sheet date, including estimates inherent in the preparation of financial statements, and are recognized in the financial statements. Nonrecognized subsequent events provide evidence about conditions that did not exist as of the balance sheet date but arose after that date. Although nonrecognized subsequent events are not recognized in the financial statements, material nonrecognized subsequent 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 recognized 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 that "gain contingencies . . . are rarely recognized after the balance sheet date but before the financial statements are issued or are available to be issued." Further, ASC 450-30-25-1 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, 2016, Utility A's regulator issued an order with respect to a routine review of A's fuel clause adjustment calculation for the period from January 1, 2015, to December 31, 2015. Utility A had not yet issued its June 30 financial statements. In this order, the regulator ruled that A should have credited certain wholesale sale margins to its retail fuel clause. The order required A to refund $5 million. Utility A was aware that intervenors were questioning this item on the basis of testimony that had been filed a few months earlier but had expected to prevail in this matter, which represented a loss contingency as of June 30. The July 15 order was a recognized subsequent event that provided additional information about the probability and amount of the loss as of June 30. Therefore, A accounted for the effect of this order in its financial statements as of and for the period ended June 30, 2016, and included the disclosures prescribed by ASC 980-605.

Interim Rates Implemented — Final Rate Order Received

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

Appeal of Prior Unfavorable Rate Order

In a prior period, Utility C's regulator ordered that a gain on a sale of an asset be used to reduce future rates. Therefore, C recorded a regulatory liability to recognize this obligation but appealed the ruling. After C's balance sheet date but before its financial statements were issued, an appellate court decided in favor of C and ruled that it did not need to reduce future rates. Intervenors immediately announced their intent to appeal the court ruling. Because of the numerous uncertainties inherent in a litigation proceeding (e.g., additional appeals), C determined that the court order did not constitute the realization of a gain and concluded that this was a nonrecognized 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, D had concluded that the likelihood of a disallowance was reasonably possible but less than probable.[1] Utility D concluded that the post-balance-sheet ruling constituted additional significant objective evidence about the likelihood of disallowance as of the balance sheet date. Accordingly, D updated its assessment of the probability of a disallowance as a result of this recognized 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.

Rate Order After the Balance Sheet Date — Order Reverses a Previous Decision by the Regulator

In a prior period, in conjunction with an order, Utility E's regulator required that E prospectively track a particular cost included in its last rate determination and, in the next rate case, should refund any excess of the amount of allowable cost in rates over the actual cost incurred. As a result of the order, E began recording a regulatory liability for the difference. The regulator issued an order after the balance sheet date but before the financial statements had been issued. In this new order, the regulator

[1] In accordance with ASC 980-360, when it becomes probable that part of the cost of a recently completed plant will be disallowed for ratemaking 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.

concluded that E did not need to refund the difference. Utility E concluded that the post-balance-sheet order represented a nonrecognized subsequent event.

Given the circumstances in which this regulatory liability was established (an obligation imposed by the regulator through an order, as opposed to an assessment of a probable loss contingency), it was acceptable for E to adopt the view that the settlement of a regulatory liability occurs only when it has been extinguished. Although this conclusion is not explicitly stated in ASC 980-405, it is consistent with the guidance in ASC 405 on liabilities that represent a legal obligation. ASC 405-20-05-2 states that an "entity may settle a liability by transferring assets to the creditor or otherwise obtaining an unconditional release." Further, ASC 405-20-40-1 states that a "debtor shall derecognize a liability if and only if it has been extinguished. A liability has been extinguished if either of [two conditions is met, one of those conditions being that the] debtor is legally released from being the primary obligor under the liability, either judicially or by the creditor." In this fact pattern, in which the regulatory liability is analogized to an ASC 405-20 liability, the liability is not satisfied until either the amounts have been refunded to the utility customers or the regulator releases E from the requirement to reduce rates. This approach is also consistent with the guidance in ASC 980-405-40-1, which states that "[a]ctions of a regulator can eliminate a liability only if the liability was imposed by actions of the regulator." Accordingly, the rate order is the discrete event that removes the requirement to reduce future rates and resulted in E's determination that the rate order was a nonrecognized subsequent event.

While there is no specific guidance in U.S. GAAP on when to recognize the impact of a regulator's ruling, there may be interpretations or applications in practice that analogize to the guidance in ASC 450, in which case an entity would have to determine whether the ruling (1) represents the recovery of a previously recognized loss or (2) results in the recognition of a gain. As discussed above, gain contingencies are rarely recognized after the balance sheet date but before the financial statements are issued.

Subsequent Natural Disaster Affects Likelihood of Recovery of a Regulatory Asset

Utility F 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 F'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 F decided to shut down the plant. Utility F had a rate-case proceeding in process at the time of the hurricane. On the basis of discussions F had with the staff of the regulatory commission, F learned that the staff was planning to propose that the deferred costs no longer be recovered. Utility F 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 F concluded that the change in judgment about likelihood of recovery of the regulatory asset resulted from a nonrecognized subsequent event. Utility F, 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 F 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 F 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 G 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 G 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. Utility G 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 G concluded that future recovery of its regulatory asset balance was probable.

In connection with its current rate proceeding, shortly after year-end, G commenced settlement discussions. Intervenors indicated that they were willing to settle the case if G would forgo the remaining amortization of the storm damage costs. While G strongly disagreed with the intervenors' position on storm damage costs, in the context of the overall settlement proposal, G was likely to agree to the settlement. On the basis of the settlement terms, no other existing regulatory assets were at risk (i.e., G 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 G was expecting. Shortly before the financial statements were issued, the parties agreed to the settlement. On the basis of precedent, G believed it was probable that its regulator would approve the settlement. Utility G concluded that this settlement represented a nonrecognized subsequent event and disclosed the settlement in the notes to the financial statements. Utility G, in its judgment, determined that the subsequent settlement discussions did not provide additional evidence about facts and conditions that existed as of the balance sheet date. Utility G 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.

Thinking It Through

Utilities 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 recognized 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 considered a recognized subsequent event if commission staff or intervenors have questioned the matter as part of the rate proceedings that occurred before the balance sheet date or it was clear that the item disallowed was subject to a prudency review in the current regulatory process.

Plant Abandonments and Disallowances of the Costs of Recently Completed Plants

ASC 980-360 provides guidance on accounting for (1) plant abandonments and (2) disallowances of the costs of recently completed plants. Generally, "plant" should be viewed as anything capitalized in "plant in service" or in CWIP. The guidance applies to all operating assets or assets under construction, most commonly to electric generating plants. Regulated utilities should also consider whether this guidance is relevant for operating assets replaced by new projects and initiatives, such as new advanced metering infrastructure projects resulting in the early retirement of existing meters.

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

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. A regulated utility should consider the length of time over which an abandoned asset will be recoverable to determine whether an indirect disallowance of the abandoned asset exists. Refer to Indirect Disallowances for additional considerations in the assessment of indirect disallowances.

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 regulated 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 indicates only 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 (when the plant meets the probable-of-abandonment criterion while still providing utility service).

Matters Related to Abandonment Accounting

The discussion above describes the overall accounting model for asset abandonments in a regulated environment; however, regulated 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 potential abandonment accounting or to the ASC 980-360 disallowance test or both. Alternatively, if an asset is to be retired, but not in the near future or 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 regulated utilities 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 regulated 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.

The determination of whether abandonment is probable in advance of a final decision to retire a plant is subject to judgment. Factors for a regulated utility to consider in assessing the likelihood of abandonment may include the following:

- 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.

Regulated utilities 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.

Example — Reconsideration of Abandonment Decision

A regulated utility previously concluded that an asset abandonment was probable and estimable and recorded a loss estimating less than a full return on and of the asset. In a subsequent period, the regulated utility concluded that the abandonment is no longer 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 back to plant in service or CWIP, as applicable. Further, ASC 980-360-35-4 describes the notion of adjusting the amount of the abandoned asset as estimates change, which supports the 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.

Regulated 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 prudency of a recently completed plant is being challenged in a current rate proceeding, a regulated utility must use significant judgment in evaluating the likelihood and estimate of a cost disallowance. If the regulated 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.

Recently Completed Plant

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 been defined on the basis of facts and circumstances, resulting in some diversity. 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. If an unregulated affiliate transfers a completed plant to a regulated utility affiliate, disallowances should be evaluated under ASC 980-360 at the time of the transfer because the costs of the plant are then subject to the provisions of ASC 980-10. The cost disallowance guidance in ASC 980-360 does not contain the concept of “major.” As a result, in the evaluation of potential cost disallowances, the guidance in ASC 980-360 on evaluating potential cost disallowances applies to all recently completed plant.

ASC 980-360 also indicates that a disallowance of plant cost resulting from a cost cap must be recorded as soon as it is evident that the *estimated* cost at completion of the project will exceed the cap. Therefore, the application of ASC 980-360 may result in disallowance losses before an asset is placed in service and before construction costs actually exceed the cap. If additional increases in the estimated cost of the plant become probable, those increases would also be recognized as disallowance losses.

Indirect Disallowances

ASC 980-360 also addresses explicit, but indirect, disallowances that occur when no return or a reduced return is provided for all or a portion of the recently completed 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 amount of the indirect disallowance, a regulated utility should calculate the present value of the future cash flows permitted by the regulator by using the regulated utility’s incremental borrowing rate. 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 ratemaking 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. The determination of a reasonable return requires significant judgment.

Considerations for Disallowances Outside the Scope of ASC 980-360

Cost disallowances for plants that are not recently completed are recognized in accordance with general U.S. GAAP. For example, assume that (1) a regulated utility puts a new plant into service and then goes through a rate case when the prudency of the costs is 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. The plant costs are questioned a few years later in the next rate case, and 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. Rather, an entity should apply the impairment criteria in ASC 360 when evaluating impairment of a plant that is not recently completed. Refer to Impairment Considerations for more details.

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 issues a final order addressing 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 on the significant terms of the rate case. Once consensus is reached, 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 from the initiation of a rate case to the effective date of new customer rates 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 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.
- Additional 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 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 "[f]or 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." An entity should determine the level at which assets are grouped on the basis of the entity's 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 power purchase 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.

Asset Group Impairment and Measurement

When events or changes in circumstances indicate that the carrying amount of an asset or asset group may not be recoverable, the utility should review its assets for impairment. Triggering events that often require recoverability evaluations for P&U companies include (but are not limited to):

- Significant adverse changes in energy and capacity prices.
- Changes in management's long-term operational view, including considerations to sell, dispose of, or retire assets within the asset group earlier than expected.
- Expectation to retire an asset earlier than expected because of time and/or resource constraints associated with applicable regulations, such as environmental compliance laws.
- Losses of major customers.

Because triggering events can change rapidly from one period to the next, an entity should (1) identify potential triggering events that could affect significant asset groups and (2) establish processes and controls to monitor them in each reporting period. Further, an entity should consider whether cautionary "early warning" disclosures are necessary when significant impairments could reasonably be possible in future periods.

To test for impairment of an asset or asset group that is held and used, a utility should compare future cash flows from the use and ultimate disposal of the asset or asset group (i.e., cash inflows to be generated by the asset or asset group less cash outflows necessary to obtain the inflows) with the carrying amount of the asset or asset group. Impairment exists when the expected future nominal (undiscounted) cash flows, excluding interest charges, are less than the carrying amount. ASC 360-10 suggests that if a test for impairment is necessary, a utility may need to review its depreciation policies even if it finds that the asset is not impaired.

If an impairment is found to exist, the impairment loss to be recorded is the amount by which the asset's carrying amount exceeds its fair value. Determining the appropriate fair value for an asset requires considerable judgment based on the relevant facts and circumstances. Quoted market prices represent strong evidence of fair value. In the absence of quoted market prices for a particular asset, market comparables may provide relevant evidence for the fair value of the asset under consideration. Discounted cash flows (discounted at a rate commensurate with the risks involved) are another data point for fair value and are commonly used in the valuation of regulated utility property. A combination of some or all of these estimates is often used to represent a fair value for an asset under consideration.

For regulated utilities subject to the provisions of ASC 980, ASC 360-10 does not specify whether an impairment loss should be recorded as a reduction in the asset's original cost or as an adjustment to the depreciation reserve. Adjustment to the original cost appears to be consistent with the notion that recognizing an impairment establishes a "new cost" for the asset. However, for enterprises that are subject to cost-based regulation and apply ASC 980, original historical cost is a key measure for determining regulated rates that may be charged to customers. Accordingly, rate-regulated enterprises may be directed by their regulators to retain original historical cost for an impaired asset and to charge the impairment loss directly to accumulated depreciation. Regulation S-X, Rule 5-02(13)(b), states:

> Tangible and intangible utility plant[s] of a public utility company shall be segregated so as to show separately the original cost, plant acquisition adjustments, and plant adjustments, as required by the system of accounts prescribed by the applicable regulatory authorities. This rule shall not be applicable in respect to companies which are not required to make such a classification.

In addition, abandonments and disallowances of plant costs accounted for under ASC 980-360 are outside the scope of ASC 360-10. Companies subject to cost-based regulation should follow the provisions of ASC 980-360 when recording an impairment loss in those situations.

Required Disclosures

ASC 360-10 requires disclosures about impairments, including:

- A description of any impaired assets and the facts and circumstances leading to the impairment.
- The amount of the impairment loss and how fair value was determined.
- The caption in the income statement in which the impairment is recorded, if not shown separately on the face of the statement.
- The business segment affected (if applicable).

Further, because an impairment accounted for under ASC 360-10 results in an asset (or asset group) carrying value equal to fair value at the time of impairment, additional disclosures related to nonrecurring fair value measurements are required by ASC 820-10.

Asset Retirement Obligations

Accounting for AROs remains a topic of significant interest in the energy and resources industry given the recent federal coal ash regulations and events that have resulted in changes in the amount and timing of estimated cash outflows (both are fundamental inputs to the calculation of asset retirement costs and liabilities that are recorded on utilities' balance sheets). The discussion below focuses on key topics related to the classification, recognition, and derecognition of AROs.

Remediation Strategy

There are often multiple ways to remediate AROs. Following one strategy might be cheaper but still be in compliance with stipulations of the legal obligation, whereas following another strategy might cost more but involve less risk and therefore be more desirable to the entity. Specific consideration should be given to whether any of the expected activities in the cost estimates are above and beyond what is legally required.

If the ultimate remediation scenario is unknown at the time the legal obligation is recorded, a best practice would be for entities to apply a probability weighting to each scenario and use the weighted-average probable cost in calculating the expected cash flows. This approach takes into account the uncertainties associated with timing and amount depending on which remediation scenario is ultimately chosen.

Triggering Events That Affect ARO Balances

Entities should continue to monitor for events or changes in circumstances that may indicate a need for changes in recorded AROs. Events or changes in circumstances that may indicate a need for reassessment include:

- A change in the law, regulation, or contract that gave rise to the ARO that results in a change to either the timing of settlement or the expected retirement costs.
- A change in management's intended use of the asset, including a change in plans for maintaining the asset to extend its useful life or to abandon the asset earlier than previously expected.
- Advancements in technology that result in new methods of settlement or changes to existing methods of settlement.
- A change in economic assumptions, such as inflation rates.

An entity should analyze its specific facts and circumstances to determine whether the estimate of the ARO needs to be reassessed.

The following is an example of new information that resulted in a change in the ARO estimate:

- In preparing the five-year financial forecast, management models asset retirement costs (ARCs) for a particular group of assets that are higher than the amount of undiscounted cash flows used in management's most recent original ARO estimate. After investigating the difference in estimates, management determined that the costs modeled in the five-year forecast reflect more current experience than the last time the ARO estimate was evaluated. Management considered the difference to be a triggering event and subsequently updated the ARO estimate to reflect the updated uninflated costs used in the five-year financial forecast.

- The key in this example is for management to regularly monitor for evidence that is contradictory to the inputs and assumptions it used in developing the original or most recent ARO estimate. This evidence could come from a variety of sources, including internal forecasting, third-party engineering studies, and knowledge obtained as retirement costs are incurred.

Changes in Estimates

Accounting for changes in estimates on an ongoing basis can result in significant complexity. As ARO estimates are revised, specific consideration needs to be given to the appropriate discount rate used in the calculation of any additional ARO layer.

An entity should calculate changes in timing or estimated expected cash flows that result in upward revisions to its ARO by using its then-current credit-adjusted risk-free interest rate. That is, the credit-adjusted risk-free rate in effect when the change occurs would be used to discount the revised estimate of the incremental expected cash flows of the retirement activity. However, if the change in timing or estimated expected cash flows results in a downward revision of the ARO, the entity should discount the undiscounted revised estimate of expected cash flows by using the credit-adjusted risk-free rate in effect on the date of initial measurement and recognition of the original ARO. Two examples are as follows:

- *Example 1* — Assume that a new asset goes into service in year 1, the undiscounted cost to perform a retirement activity 10 years from now is $100, and the current credit-adjusted discount rate is 5 percent. In year 4, based on updated information, the undiscounted cost to perform the retirement activity in year 10 has increased by $5. The present value of the $5 increase in cost would become a new cost layer that would be discounted at the then-current credit-adjusted discount rate (i.e., the year 4 credit-adjusted risk-free rate).
- *Example 2* — Assume the same base facts as Example 1, except that in year 4, the estimated undiscounted cost to perform the retirement activity has decreased by $5. The $5 reduction in undiscounted cash flows is simply deducted from the original year 1 layer of undiscounted cash flows. The original 5 percent credit-adjusted discount rate is used for the one single layer.

Determining the appropriate unit of account for the ARO is essential to ensuring that increases and decreases in undiscounted cash flows or timing of cash flows are appropriately reflected in new layers or deducted from the appropriate existing layers. For example, consider a three-unit coal-fired generation plant whose coal ash resulting from burning the coal is subject to the EPA's Disposal of Coal Combustion Residuals From Electric Utilities rule. Is the unit of account the total undiscounted cash flows related to the coal ash generated from (1) all three units in total, (2) all three units individually, (3) the individual ash ponds, or (4) something else? It is important for an entity to carefully define the ARO unit of account in the year the ARO is incurred in order to properly account for subsequent changes in estimates.

Accounting for Settlements

As remediation activities commence, entities should place specific focus on the classification of charges that are incurred. This includes the determination of which charges are truly associated with the remediation activity and should therefore be reflected as a reduction in the ARO versus other charges that should be recorded to PP&E or expense in accordance with an entity's capitalization policy.

Reporting Considerations

Entities should identify expenditures that are part of the legal/contractual retirement activity and account for those expenditures as settlements of the ARO. Often, there are other costs incurred as part of the overall project that are not part of the legal/contractual retirement obligation; those costs should be expensed as incurred. Rate-regulated entities that recover cost of removal in rates before the removal costs are actually incurred should separately identify the "nonlegal" removal activity and charge those expenditures to the associated regulatory liability.

ASC 210 defines current liabilities as "obligations whose liquidation is reasonably expected to require the use of existing resources properly classifiable as current assets, or the creation of other current liabilities." Entities should consider whether the estimated ARO expenditures over the next 12 months should be classified as current. Questions that entities should consider in making this evaluation include the following:

- Have the necessary permits been obtained to finish the work that is estimated to be completed in the next 12 months?
- Has approval been obtained to use existing resources to finish the work that is estimated to be completed in the next 12 months?
- Are there any contractual or legal deadlines that require the completion of certain projects included in the ARO cash flows within the next 12 months?

ASC 230-10-45-17 states that cash payments made to settle an ARO should be classified as operating activities. Also, in practice, nonlegal cost of removal is typically presented as an investing activity by regulated entities.

Accounting for AROs in a Business Combination

ASC 805-20-30 states that an acquirer should measure identifiable assets acquired and liabilities assumed in a business combination at fair value. PP&E acquired in a business combination may be subject to legal obligations associated with its retirement. AROs should be recognized as of the acquisition date as a separate liability and measured at fair value.

Questions often arise about how to account for the associated ARC in PP&E. Companies should obtain an understanding of how the ARO was considered in the estimation of the fair value of PP&E. If the PP&E fair value measurement did not take into account the PP&E owner's cash outflows related to the ARO, the PP&E fair value has effectively included an element for the ARC. If the fair value estimate took into account the cash outflows related to the ARO (and thus the plant value was effectively reduced from what the value would have been without the ARO), it would be appropriate to separately capitalize an ARC by increasing the carrying amount of the PP&E by the same amount as the liability.

The example below demonstrates how an entity would consider and account for the ARC in a business combination.

Example

Company A acquires a natural-gas-fired generating plant from Company B and assumes an ARO with a fair value of $50 million. The ARO arises from a contractual commitment to dismantle the plant and restore the land to a grassy field upon retirement. At closing, A pays B $1 billion.

Subsequently, A hires a valuation consultant, who concludes that the plant's fair value on the acquisition date was $1 billion. The valuation is based on a discounted cash flow model that reflects cash outflows the year after plant retirement for dismantlement, disposal, landscaping, and so forth.

In this situation, A should record the following entries:

PP&E	1,000,000,000	
PP&E — ARC	50,000,000	
ARO		50,000,000
Cash		1,000,000,000

As shown in the example above, it is important for companies to consider whether AROs have been factored into the calculation of the fair value of PP&E. If A had not done so, it might have inappropriately recorded the $50 million difference to goodwill or intangible assets.

Alternative Revenue Programs

Traditionally, rate-regulated utilities bill customers on the basis of approved rates and usage. In some jurisdictions, regulators have authorized the use of alternative revenue programs that allow rate-regulated utilities to bill customers certain incremental amounts associated with prior activities.

ASC 980-605-25-1 and 25-2 segregate the major alternative revenue programs into two categories, Type A and Type B. As ASC 980-605-25-2 explains:

- "Type A programs adjust billings for the effects of weather abnormalities or broad external factors or to compensate the [rate-regulated] utility for demand-side management initiatives." Examples include no-growth plans and similar conservation efforts.
- "Type B programs provide for additional billings (incentive awards) if the [rate-regulated] utility achieves certain objectives, such as reducing costs, reaching specified milestones, or demonstratively improving customer service."

ASC 980-605-25-3 states that "[b]oth types of programs enable the utility to adjust rates in the future (usually as a surcharge applied to future billings) in response to past activities or completed events." Accordingly, the key judgment is determining whether the adjustment to rates is for past activities or future activities.

ASC 980-605-25-4 identifies the following conditions that must be met for a rate-regulated utility to recognize additional revenue under an alternative revenue program once the specific events that permit billing of additional revenues under Type A and Type B programs have been completed:

a. The program is established by an order from the utility's regulatory commission that allows for automatic adjustment of future rates. Verification of the adjustment to future rates by the regulator would not preclude the adjustment from being considered automatic.

b. The amount of additional revenues for the period is objectively determinable and is probable of recovery.

c. The additional revenues will be collected within 24 months following the end of the annual period in which they are recognized.

These conditions are not to be used as guidelines; rather, they set a high hurdle for recognizing revenue under an alternative revenue program, and all of these conditions must be met.

This guidance is limited to rate-regulated utilities under ASC 980 and, as noted above, to situations in which future rates would be adjusted to provide additional revenue "in response to past activities or completed events." It does not provide a basis, for example, for circumventing the limitation in ASC 980-340 on recording an ongoing equity carrying charge as revenue except in certain limited circumstances, such as a formula rate tariff that includes an equity return component.

Types of Alternative Revenue Programs

As discussed above, ASC 980-605-25-1 and 25-2 provide specific examples of alternative revenue programs, including programs that adjust billings for the effects of weather abnormalities or broad external factors as well as programs that compensate the utility for demand-side management initiatives (e.g., no-growth plans) or provide for additional billings if the utility achieves certain objectives, such as reducing costs, reaching specified milestones, or demonstratively improving customer service. These examples are programs that were popular at the time the EITF ultimately issued EITF Issue No. 92-7, "Accounting by Rate-Regulated Utilities for the Effects of Certain Alternative Revenue Programs."

While the Type A and Type B programs were specifically identified as programs that qualify as alternative revenue programs (assuming that the conditions in ASC 980-605-25-4 are met), we do not believe that this guidance is restricted to those programs. Various ratemaking mechanisms have developed over time, and many are consistent with the philosophy underlying this literature. A program that many companies have concluded qualifies as an alternative revenue program is a cost-based formula rate tariff with a true-up provision, in which any undercollected revenue requirement adjusts rates prospectively and is billed to the customer within 24 months of year-end.

Determining whether a program qualifies as an alternative revenue program in which revenue can be recorded currently depends on the specific facts and circumstances of each situation and requires judgment. Utilities are encouraged to consult with their independent auditor when such situations arise.

Considerations Related to 24-Month Collection Period

As discussed above, the condition in ASC 980-605-25-4(c) requires additional revenues to be collected within 24 months following the end of the annual period in which they are recognized (the "24-month collection period"). Sometimes, alternative revenue programs provide for collection over a period that begins before or during, or ends after, the 24-month collection period. In these instances, utilities must determine the appropriate accounting treatment for such collections.

One approach is to conclude that the additional revenues do not qualify for recognition under the alternative revenue program guidance because some of the additional revenues will not be collected within 24 months following the end of the annual period in which they were recognized. Under this approach, revenue is recognized when billed.

Another approach is to recognize the additional revenues for amounts that **will be** collected within 24 months following the end of the annual period in which they were recognized. For any remaining amounts, a utility could subsequently recognize revenue once the recognition criteria discussed above are met (i.e., when such amounts will be collected within 24 months of the end of the annual period).

Both of the approaches above are acceptable, and utilities should disclose their accounting policy related to this matter if material.

Accounting for Credit Balances

The guidance in ASC 980-605 does not address the accounting for credit balances (amounts due to customers) that may also result from alternative revenue programs. These credits should be recognized as liabilities because they are considered "refunds" of past revenues that are accounted for as (1) contingent liabilities that meet the conditions for accrual under ASC 450-20 or (2) regulatory liabilities in accordance with ASC 980-605-25-1.

Issuance of ASU 2014-09, *Revenue From Contracts With Customers*

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 when alternative revenue programs exist. P&U entities within the scope of ASC 980-605-15 will continue to recognize additional revenues allowable for alternative revenue programs if those programs meet the criteria in ASC 980-605-25-4.

In the statement of comprehensive income, ASU 2014-09 will require that revenues arising from alternative revenue programs be presented separately from revenues arising from contracts with customers that are within the scope of the ASU. ASU 2014-09 does not explicitly address the accounting and financial statement presentation effects when revenues arising from alternative revenue programs are ultimately billed to customers. Because of the lack of explicit guidance, the AICPA Power and Utility Entities Revenue Recognition Task Force is evaluating this issue as part of its industry-focused implementation efforts related to ASU 2014-09.

Normal Purchases and Normal Sales (NPNS) Scope Exception

Under ASC 815-10-15-35, for a "contract that meets the net settlement provisions of [ASC] 815-10-15-100 through 15-109 and the market mechanism provisions of [ASC] 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 company 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. 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 execution 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 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 net-settle and will result in physical delivery. Entities should also consider whether the ability to enter into offsetting positions indicates that the coal is RCC, as that term 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 contracts meet the definition of a derivative (i.e., whether the coal is RCC). If volumetric optionality exists, the contracts will not qualify for the NPNS election.[2]

Impact on Certain Electricity Forward Contracts in Nodal Energy Markets

In 2013, EEI submitted an inquiry to the SEC regarding NPNS eligibility for certain forward electricity transactions in nodal markets. The inquiry focused 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 (1) the delivery point of the forward contract (the source) differs from the location of the purchaser's customers (the sink) and (2) locational marginal pricing (LMP) charges and credits are therefore incurred in connection with the delivery of power to end users.

In August 2015, the FASB issued ASU 2015-13, which amends ASC 815 to clarify the application of the NPNS exception to purchases or sales of electricity on a forward basis that are transmitted through, or delivered to a location within, a nodal energy market. For a derivative contract to be classified as NPNS, the contract cannot settle net and must result in physical delivery. ASU 2015-13 concludes that a forward contract to purchase or sell electricity — at a specified location — that must be transmitted through or delivered to a grid operated by an ISO is not net-settled by virtue of spot purchase and sale activity with the ISO to transmit the electricity to the customer load zone and thus may qualify for the NPNS scope exception.

ASU 2015-13 clarifies the Board's view that the use of LMP by an ISO does not constitute net settlement of the contract. This ASU became effective upon issuance and is applied prospectively, allowing entities to designate qualifying contracts as normal purchases or normal sales. In the period of adoption, entities

[2] A power purchase agreement that is a capacity contract may qualify for the NPNS election under ASC 815-10-15-45 through 15-51.

should include the disclosures in ASC 250-10-50-1(a) and ASC 250-10-50-2. Entities that previously designated these types of contracts as NPNS may continue to do so if such a designation would have been appropriate under the ASU. In documenting an NPNS designation, companies may wish to consider specifically noting the role of the nodal energy market in reaching the delivery location and why that activity does not constitute net settlement. In addition, the ASU is specific to transactions in nodal markets, so entities should not apply the ASU's guidance to other transactions by analogy.

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 (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 that they have appropriate controls in place to confirm the accuracy of volumetric data sent into and withdrawn from the RTO.

Section 4 — Updates to Accounting Guidance

Financial Instruments

Impairment

Background

In June 2016, the FASB issued ASU 2016-13, which amends guidance on the impairment of financial instruments. The ASU adds to U.S. GAAP an impairment model (known as the current expected credit loss (CECL) model) that is based on expected losses rather than incurred losses. Under the new guidance, an entity recognizes as an allowance its estimate of expected credit losses, which the FASB believes will result in more timely recognition of such losses. The ASU is also intended to reduce the complexity of U.S. GAAP by decreasing the number of credit impairment models that entities use to account for debt instruments.

Once effective (see Effective Date below), the new guidance will significantly change the accounting for credit impairment.

Key provisions of the ASU are discussed below. For additional information, see Deloitte's June 17, 2016, *Heads Up*.

Thinking It Through

In late 2015, the FASB established a transition resource group (TRG) for credit losses. Like the TRG for the new revenue recognition standard, the credit losses TRG does not issue guidance but provides feedback to the FASB on potential implementation issues. By analyzing and discussing such issues, the TRG helps the Board determine whether it needs to take further action (e.g., by clarifying or issuing additional guidance).

The CECL Model

Scope

The CECL model applies to most[1] debt instruments (other than those measured at fair value), trade receivables, net investments in leases, reinsurance receivables that result from insurance transactions, financial guarantee contracts,[2] and loan commitments. However, available-for-sale (AFS) debt securities are excluded from the model's scope and will continue to be assessed for impairment under the guidance in ASC 320 (the FASB moved the impairment model for AFS debt securities from ASC 320 to ASC 326-30 and has made limited amendments to the impairment model for AFS debt securities, as discussed below).

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 will recognize its estimate of expected credit losses for financial assets as of the end of the reporting period. Credit impairment will be recognized as an allowance — or contra-asset — rather than as a direct write-down of the amortized

[1] The following debt instruments would not be accounted for under the CECL model:
- 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.

[2] The CECL model does not apply to financial guarantee contracts that are accounted for as insurance or measured at fair value through net income.

cost basis of a financial asset. However, the carrying amount of a financial asset that is deemed uncollectible will be written off in a manner 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 (HTM) debt securities). However, the ASU states that "an entity is not required to measure expected credit losses on a financial asset . . . in which historical credit loss information adjusted for current conditions and reasonable and supportable forecasts results in an expectation that nonpayment of the [financial asset's] amortized cost basis is zero." U.S. Treasury securities and certain highly rated debt securities may be assets the FASB contemplated when it decided to allow an entity to recognize zero credit losses on an asset, but the ASU does not so indicate. Regardless, there are likely to be challenges associated with measuring expected credit losses on financial assets whose risk of loss is low.

Measurement of Expected Credit Losses

The ASU describes the impairment allowance as a "valuation account that is deducted from the amortized cost basis of the financial asset(s) to present the net carrying value at the amount expected to be collected on the financial asset." An entity can use a number of measurement approaches to determine the impairment allowance. Some approaches project future principal and interest cash flows (i.e., a discounted cash flow method) while others project only future principal losses. Regardless of the measurement method used, an entity's estimate of expected credit losses should reflect those losses occurring over the contractual life of the financial asset.

When determining the contractual life of a financial asset, an entity is required to consider expected prepayments either as a separate input in the determination or as an amount embedded in the credit loss experience that it uses to estimate expected credit losses. The entity is not allowed to consider expected extensions of the contractual life unless it reasonably expects to execute a troubled debt restructuring with the borrower by the reporting date.

An entity must consider all available relevant information when estimating expected credit losses, including details about past events, current conditions, and reasonable and supportable forecasts and their implications for expected credit losses. That is, while the entity is able to use historical charge-off rates as a starting point for determining expected credit losses, it has to evaluate how conditions that existed during the historical charge-off period may differ from its current expectations and accordingly revise its estimate of expected credit losses. However, the entity is not required to forecast conditions over the contractual life of the asset. Rather, for the period beyond which the entity can make reasonable and supportable forecasts, the entity reverts to historical credit loss experience.

Thinking It Through

It will most likely be challenging for entities to measure expected credit losses. Further, one-time or recurring costs may be associated with the measurement, some of which may be related to system changes and data collection. While such costs will vary by institution, nearly all entities will incur some costs when using forward-looking information to estimate expected credit losses over the contractual life of an asset.

Unit of Account

The CECL model does 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 is required to evaluate financial assets within the scope of the model on a collective (i.e., pool) basis when assets share similar risk characteristics. If a financial asset's risk characteristics are not similar to the risk characteristics of any of 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.

Thinking It Through

The ASU requires an entity to collectively measure expected credit losses on financial assets that share similar risk characteristics (including HTM securities). While certain loans are pooled or evaluated collectively under current U.S. GAAP, entities may need to refine their data-capturing processes to comply with the new requirements.

Write-Offs

Like current guidance, the ASU requires an entity to write off the carrying amount of a financial asset when the asset is deemed uncollectible. However, unlike current requirements, the ASU's write-off guidance also applies to AFS debt securities.

AFS Debt Securities

The CECL model does not apply to AFS debt securities. Instead, the FASB decided to make targeted improvements to the existing other-than-temporary impairment model in ASC 320 for certain AFS debt securities to eliminate the concept of "other than temporary" from that model.[3] Accordingly, the ASU states that an entity:

- Must use an allowance approach (vs. permanently writing down the security's cost basis).
- Must limit the allowance to the amount at which the security's fair value is less than its amortized cost basis.
- May not consider the length of time fair value has been less than amortized cost.
- May not 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") or (2) the requirement under ASC 320 for an entity to recognize in net income the impairment amount only related to credit and to recognize in other comprehensive income (OCI) the noncredit impairment amount. However, the ASU does require an entity to use an allowance approach for certain AFS debt securities when recognizing credit losses (as opposed to a permanent write-down of the AFS security's cost basis). As a result, the entity would reverse credit losses through current-period earnings on an AFS debt security in both of the following circumstances:

- 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

[3] The amendments do not apply to an AFS debt security that an entity intends to sell or will more likely than not be required to sell before the recovery of its amortized cost basis. If an entity intends to sell or will more likely than not be required to sell a security before recovery of its amortized cost basis, the entity would write down the debt security's amortized cost to the debt security's fair value as required under existing U.S. GAAP.

cost), the entity would reverse the *entire* credit loss previously recognized and recognize a corresponding adjustment to its allowance for credit losses.

- 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.

PCD Assets

For purchased financial assets with credit deterioration (PCD assets),[4] the ASU requires an entity's method for measuring expected credit losses to be consistent with its method for measuring expected credit losses for originated and purchased non-credit-deteriorated assets. Upon acquiring a PCD asset, the entity would recognize its allowance for expected credit losses as an adjustment that increases the cost basis of the asset (the "gross-up" approach). After initial recognition of the PCD asset and its related allowance, the entity would continue to apply the CECL model to the asset — that is, any changes in the entity's estimate of cash flows that it expects to collect (favorable or unfavorable) would be recognized immediately in the income statement. Interest income recognition would be based on the purchase price plus the initial allowance accreting to the contractual cash flows.

Thinking It Through

Under current U.S. GAAP, an acquired asset is considered credit-impaired when it is probable that the investor would be unable to collect all contractual cash flows as a result of deterioration in the asset's credit quality since origination. Under the ASU, a PCD asset is an acquired asset that has experienced a more-than-insignificant deterioration in credit quality since origination. Consequently, entities will most likely need to use more judgment than they do under current guidance to determine whether an acquired asset has experienced significant credit deterioration.

Also, under the current accounting for purchased credit-impaired assets, an entity recognizes unfavorable changes in expected cash flows as an immediate credit impairment but treats favorable changes in expected cash flows that are in excess of the allowance as prospective yield adjustments. The CECL model's approach to PCD assets eliminates this asymmetrical treatment in cash flow changes. However, in a manner consistent with current practice, the CECL model precludes an entity from recognizing as interest income the discount embedded in the purchase price that is attributable to expected credit losses as of the date of acquisition.

Disclosures

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

- Credit quality.[5]
- Allowances for expected credit losses.
- Policies for determining write-offs.

[4] The ASU defines PCD assets as "[a]cquired individual financial assets (or acquired groups of financial assets with similar risk characteristics) that, as of the date of acquisition, have experienced a more-than-insignificant deterioration in credit quality since origination, as determined by an acquirer's assessment."

[5] Short-term trade receivables resulting from revenue transactions within the scope of ASC 605 and ASC 606 are excluded from these disclosure requirements.

- Past-due status.
- Nonaccrual status.
- PCD assets.
- Collateral-dependent financial assets.

In addition, other disclosures are required as follows:

- Public business entities that meet the U.S. GAAP definition of an SEC filer[6] must disclose credit quality indicators disaggregated by year of origination for a five-year period.
- Public business entities that do not meet the U.S. GAAP definition of an SEC filer must disclose credit-quality indicators disaggregated by year of origination. However, upon adoption of the ASU, they would be required to disclose such information for only the previous three years, and would add another year of information each year after adoption until they have provided disclosures for the previous five years.
- Other entities are not required to disclose credit quality indicators disaggregated by year of origination.

Effective Date and Transition

Effective Date

For public business entities that meet the U.S. GAAP definition of an SEC filer, the ASU is effective for fiscal years beginning after December 15, 2019, including interim periods therein.

For public business entities that do not meet the U.S. GAAP definition of an SEC filer, the ASU is effective for fiscal years beginning after December 15, 2020, including interim periods therein.

For all other entities, the ASU is effective for fiscal years beginning after December 15, 2020, and interim periods within those fiscal years beginning after December 15, 2021.

In addition, entities are permitted to early adopt the new guidance for fiscal years beginning after December 15, 2018, including interim periods therein.

Transition Approach

For most debt instruments, entities must record a cumulative-effect adjustment to the statement of financial position as of the beginning of the first reporting period in which the guidance is effective (modified retrospective approach). However, instrument-specific transition provisions are provided for other-than-temporarily impaired debt securities, PCD assets, and certain beneficial interests within the scope of ASC 325-40.

Thinking It Through

Reporting entities currently use various methods to estimate credit losses. Some apply simple approaches that take into account average historical loss experience over a fixed time horizon. Others use more sophisticated "migration" analyses and forecast modeling techniques. Under

[6] Under U.S. GAAP, an SEC filer is defined as follows:
"An entity that is required to file or furnish its financial statements with either of the following:
a. The Securities and Exchange Commission (SEC)
b. With respect to an entity subject to Section 12(i) of the Securities Exchange Act of 1934, as amended, the appropriate agency under that Section.
Financial statements for other entities that are not otherwise SEC filers whose financial statements are included in submission by another SEC filer are not included within this definition."

the CECL model, for any approach that is based solely on historical loss experience, an entity needs to consider the effect of forward-looking information over the remaining contractual life of a financial asset. In addition, as ASU 2016-13 states, "for periods beyond which the entity is able to make or obtain reasonable and supportable forecasts of expected credit losses, an entity shall revert to historical loss information determined in accordance with [ASC] 326-20-30-8 that is reflective of the contractual term of the financial asset or group of financial assets."

For instance, assume that an entity uses annualized loss rates to determine the amount of probable unconfirmed losses on its homogeneous pools of loans as of the reporting date. When moving to the CECL model, the entity may need to revise its allowance method by adjusting the fixed time horizon (i.e., annualized loss rates) to equal a period that represents the full contractual life of the instrument. Entities using a probability-of-default (PD) approach may need to revise their PD and loss-given-default (LGD) statistics to incorporate the notion of lifetime expected losses. Today, an entity's PD approach might be an estimate of the probability that default will occur over a fixed assessment horizon, which is less than the full contractual life of the instrument (often one year). Similarly, an entity needs to revise its LGD statistic to incorporate the notion of lifetime expected losses (i.e., the percentage of loss over the total exposure if default were to occur during the full contractual life of the instrument).

Classification and Measurement

Background

ASU 2016-01 amends the guidance on the classification and measurement of financial instruments. The amendments contain changes related to the following:

- Accounting for equity investments (apart from those that are accounted for under the equity method or those that are consolidated).
- Recognition of changes in fair value attributable to changes in instrument-specific credit risk for financial liabilities for which the fair value option has been elected.
- Determining the valuation allowance for deferred tax assets (DTAs) related to AFS debt securities.
- Disclosure requirements for financial assets and financial liabilities.

For public business entities, the new standard is effective for fiscal years beginning after December 15, 2017, including interim periods therein. For all other entities, the standard is effective for fiscal years beginning after December 15, 2018, and interim periods within fiscal years beginning after December 15, 2019. Early adoption of certain of the standard's provisions is permitted for all entities. Nonpublic business entities are permitted to adopt the standard in accordance with the effective date for public business entities. For more information about ASU 2016-01, see Deloitte's January 12, 2016, *Heads Up*.

Classification and Measurement of Equity Investments

The amendments will require entities to carry all investments in equity securities at fair value, with changes in fair value recorded through earnings, unless the equity investments are accounted for under the equity method or are consolidated. For equity investments that do not have a readily determinable fair value, the guidance will permit a practicability exception under which the equity investment would be measured at cost less impairment, if any, plus or minus observable price changes in orderly transactions. This practicability exception would not be available to reporting entities that are investment companies, broker-dealers in securities, or postretirement benefit plans.

An entity that has elected the practicability exception for equity investments that do not have a readily determinable fair value is required to assess whether the equity investment is impaired by qualitatively considering the indicators described in ASC 321-10-35-3. If, on the basis of the qualitative assessment, the equity investment is impaired, an entity would be required to record an impairment equal to the amount by which the carrying value exceeds fair value. The entity should no longer evaluate whether such impairment is other than temporary.

Thinking It Through

Under current U.S. GAAP, marketable equity securities other than equity method investments or those that result in consolidation of the investee are classified as either (1) held for trading, with changes in fair value recognized in earnings, or (2) AFS, with changes in fair value recognized in other comprehensive income (OCI). Further, nonmarketable equity securities for which the fair value cannot be readily determined generally would be measured at cost (less impairment) unless the fair value option is elected. Under the new guidance, since equity securities can no longer be accounted for as AFS, entities holding such investments could see more volatility in earnings. Entities' application of the practicability exception to investments without readily determinable fair values may reduce such earnings volatility, but this exception is not available to broker-dealers.

Changes in Fair Value of a Liability Attributed to Changes in Instrument-Specific Credit Risk

For financial liabilities (excluding derivative instruments) for which the fair value option has been elected, the amendments will require an entity to separately recognize in OCI any changes in fair value associated with instrument-specific credit risk. The guidance indicates that the portion of the total change in fair value that exceeds the amount resulting from a change in a base market risk (such as a risk-free interest rate) may be attributable to instrument-specific credit risk, but also acknowledges that there may be other methods an entity may use to determine instrument-specific credit risk.

Valuation Allowance on a DTA Related to an AFS Debt Security

The new guidance eliminates the diversity in practice related to the evaluation of the need for a valuation allowance for DTAs related to debt securities that are classified as AFS. Under current U.S. GAAP, entities may perform this evaluation either separately from their other DTAs or in combination with them. The new guidance clarifies that an entity should "evaluate the need for a valuation allowance on a [DTA] related to [AFS] securities in combination with the entity's other [DTAs]."

Changes to Disclosure Requirements

For nonpublic business entities, the amendments eliminate the requirement to disclose the fair value of financial instruments measured at amortized cost. In addition, for such financial instruments, public business entities would not be required to disclose (1) the information related to the methods and significant assumptions used to estimate fair value or (2) a description of the changes in the methods and significant assumptions used to estimate fair value. The guidance also clarifies U.S. GAAP by eliminating the provisions in ASC 825 that had been interpreted to permit an "entry" price notion for estimating the fair value of loans for disclosure purposes. The amendments require a public business entity to disclose the fair value in accordance with the exit price notion in ASC 820. In addition, all entities are required to disclose in the notes to the financial statement all financial assets and financial liabilities grouped by (1) measurement category (i.e., amortized cost or fair value — net income or OCI) and (2) form of financial asset (i.e., securities and loans/receivables).

Effect of Derivative Contract Novations on Existing Hedge Accounting

Background and Key Provisions of ASU 2016-05

In March 2016, the FASB issued ASU 2016-05, which clarifies the accounting for derivative contract novations on existing hedge accounting relationships. A derivative novation occurs when one party to the derivative contract assigns its rights and obligations to a new party (i.e., legally replaces itself with another party). Approval for the novation is typically required by the existing derivative counterparty. After the novation, the entity that was replaced by the new party no longer has any rights or obligations under the contract.

Derivative novations can occur for various reasons, including the following:

- As a result of a financial institution merger, to designate the surviving entity as the new counterparty.
- As a vehicle for exiting a line of business or moving risk exposures between different legal entities of the same parent company.
- To satisfy laws or regulatory requirements (e.g., as a means of complying with requirements to use central derivative clearing counterparties).

Under ASC 815, an entity must discontinue a hedging relationship if (1) the hedging derivative instrument expires or is sold, terminated, or exercised or (2) it wishes to change a critical term of the hedging relationship. Before ASU 2016-05 was issued, however, ASC 815 did not explicitly address how a novation of a hedging derivative affects a hedging relationship, and this ambiguity resulted in inconsistent application in practice.

ASU 2016-05 (codified in ASC 815) clarifies that "a change in the counterparty to a derivative instrument that has been designated as the hedging instrument in an existing hedging relationship would not, **in and of itself**, be considered a termination of the derivative instrument" (emphasis added) or "a change in a critical term of the hedging relationship." As long as all other hedge accounting criteria in ASC 815 are met, a hedging relationship in which the hedging derivative instrument is novated would not be discontinued or require redesignation. This clarification applies to both cash flow and fair value hedging relationships.

Thinking It Through

The Basis for Conclusions of ASU 2016-05 states that "a reporting entity always is required to assess the creditworthiness of the derivative instrument counterparty in a hedging relationship (both in the normal course of the hedging relationship and upon a novation)." Although an entity would not be required to discontinue the hedging relationship solely as a result of a change in counterparty, the entity would need to consider the counterparty's creditworthiness. If the new counterparty's creditworthiness differs significantly from that of the original counterparty, the hedging relationship may no longer be a highly effective hedge, which would trigger discontinuation of the hedged relationship.

Effective Date and Transition

For public business entities, the ASU is effective for fiscal years beginning after December 15, 2016, including interim periods therein. For all other entities, it is effective for fiscal years beginning after

December 15, 2017, and interim periods within fiscal years beginning after December 15, 2018. An entity would apply the guidance prospectively unless it elects modified retrospective transition. Early adoption is permitted, including in an interim period.

Prospective Approach

Under the prospective approach, an entity would apply the amendments only to hedging relationships in which a counterparty to the hedging derivative is changed after the date the reporting entity adopted ASU 2016-05.

Modified Retrospective Approach

If elected, the modified retrospective approach will apply to all derivative instruments that satisfy **all** of the following conditions:

- "The derivative instrument was outstanding during all or a portion of the periods presented in the financial statements."
- "The derivative instrument was previously designated as a hedging instrument in a hedging relationship."
- "The hedging relationship was dedesignated solely due to a novation of the derivative instrument, and all other hedge accounting criteria [in ASC 815] would have otherwise continued to be met."[7]

For such hedging relationships, an entity would remove from the financial statements the effect of the hedge dedesignation that resulted from the novation for each period presented. The entity also would adjust beginning retained earnings to reflect the cumulative effect on the financial statements of derivatives that (1) meet the requirements above and (2) were dedesignated from hedging relationships as a result of novations that occurred before the beginning of the earliest period presented.

Thinking It Through

To apply the modified retrospective approach, an entity is required to assess hedge effectiveness and measure ineffectiveness as required by the original hedge documentation under ASC 815 for all periods between (1) the date on which the hedging relationship was dedesignated solely because of a novation and (2) the date on which the entity adopts ASU 2016-05.

Disclosure Requirements

Under either transition approach, an entity must provide the disclosures required by ASC 250-10-50-1(a) and 50-2 about the nature of and reason for the change in accounting principle, as applicable, in the period in which it adopts the ASU. An entity electing the modified retrospective approach must also provide the disclosures required by ASC 250-10-50-1(b)(1) and (b)(3) about the amounts retrospectively adjusted and the cumulative effect on retained earnings, as applicable.

[7] Such criteria would include those that require assessment of the possibility of a default by the counterparty to the hedging derivative. See ASC 815-20-35-14 through 35-18.

Contingent Put and Call Options in Debt Instruments

Background and Key Provisions of ASU 2016-06

To determine how to account for debt instruments with embedded features, including contingent put and call options, an entity is required to assess whether the embedded derivatives must be bifurcated from the host contract and accounted for separately. Part of this assessment consists of evaluating whether the embedded derivative features are clearly and closely related to the debt host. Before it was amended by ASU 2016-06, ASC 815-15 stated that contingently exercisable options had to be indexed only to interest rates or credit risk to be considered clearly and closely related to a debt host.

ASU 2016-06 was issued to address inconsistent interpretations of whether the event that triggers an entity's ability to exercise the embedded contingent option must be indexed to interest rates or credit risk for that option to qualify as clearly and closely related. Diversity in practice had developed because the four-step decision sequence in ASC 815-15-25-42 focused only on whether the payoff was indexed to something other than an interest rate or credit risk. As a result, entities were uncertain whether they should (1) determine whether the embedded features are clearly and closely related to the debt host solely on the basis of the four-step decision sequence or (2) first apply the four-step decision sequence and then also evaluate whether the event triggering the exercisability of the contingent put or call option was indexed only to an interest rate or credit risk (and not some extraneous event or factor).

The ASU clarifies that in assessing whether an embedded contingent put or call option is clearly and closely related to the debt host, an entity is required to perform only the four-step decision sequence in ASC 815-15-25-42 as amended by the ASU. The entity does not have to separately assess whether the event that triggers its ability to exercise the contingent option is itself indexed only to interest rates or credit risk.

See Deloitte's March 16, 2016, *Heads Up* for more information.

Effective Date and Transition

For public business entities, the ASU is effective for financial statements issued for fiscal years beginning after December 15, 2016, including interim periods therein. For all other entities, it is effective for financial statements issued for fiscal years beginning after December 15, 2017, and interim periods beginning after December 15, 2018. An entity can early adopt the ASU, including in an interim period; however, if it early adopts in an interim period, it should reflect any adjustment as of the beginning of the fiscal year that includes the interim period.

An entity will apply a modified retrospective transition approach that requires it to use the four-step decision sequence to determine for existing debt instruments whether an embedded derivative is clearly and closely related to the debt host and to take into account the economic characteristics and risks of the host contract and the embedded option that existed on the date it issued or acquired the instrument.

If bifurcation of an embedded derivative is no longer required as a result of application of the ASU, the entity will determine the carrying amount of the debt instrument on the date of adoption as the aggregate of the carrying amount of the debt host contract and the fair value of the previously bifurcated embedded derivative. Any premium or discount resulting from such aggregation will not affect the entity's assessment of whether the call (put) option is clearly and closely related to the debt instrument. The entity will not make any cumulative-effect adjustments to beginning retained earnings.

An entity that is no longer required to bifurcate an embedded derivative from a debt instrument as a result of applying the guidance in the ASU also has a one-time option, as of the beginning of the fiscal year for which the amendments are effective, to irrevocably elect to measure that debt instrument in its entirety at fair value and recognize changes in fair value in earnings (if that instrument is within the scope of ASC 825-10-15-4 and 15-5). The effects of such an election would be reported as a cumulative-effect adjustment to the beginning retained earnings of the fiscal year of adoption. The entity should elect to apply the fair value option on an instrument-by-instrument basis.

Measurement-Period Adjustments

Background

In September 2015, the FASB issued ASU 2015-16, which amended the guidance in ASC 805 on the accounting for measurement-period adjustments. The ASU was issued as part of the FASB's simplification initiative in response to stakeholder feedback that restating prior periods to reflect adjustments made to provisional amounts recognized in a business combination adds cost and complexity to financial reporting but does not significantly improve the usefulness of the information provided to users. Key provisions of the ASU are discussed below. For more information, see Deloitte's September 30, 2015, *Heads Up*.

Key Provisions of the ASU

Under previous guidance, when an acquirer identified an adjustment to provisional amounts during the measurement period, the acquirer was required to revise comparative information for prior periods, including making any change in depreciation, amortization, or other income effects recognized in completing the initial accounting, as if the accounting for the business combination had been completed as of the acquisition date.

The ASU requires an acquirer to recognize adjustments to provisional amounts that are identified during the measurement period in the reporting period in which the adjustment amounts are determined. The effect on earnings of changes in depreciation or amortization, or other income effects (if any) as a result of the change to the provisional amounts, calculated as if the accounting had been completed as of the acquisition date, must be recorded in the reporting period in which the adjustment amounts are determined rather than retrospectively.

Thinking It Through

Although the ASU changes the accounting for measurement-period adjustments, it does not change the definition of a measurement-period adjustment, which is an adjustment to the amounts provisionally recognized for the consideration transferred, the assets acquired, and the liabilities assumed as a result of "new information obtained about facts and circumstances that existed as of the acquisition date that, if known, would have affected the measurement of the amounts recognized as of that date." Errors, information received after the measurement period ends, or information received about events or circumstances that did not exist as of the acquisition date are not measurement-period adjustments.

Disclosure Requirements

The ASU also requires that the acquirer present separately on the face of the income statement, or disclose in the notes, the portion of the amount recorded in current-period earnings by line item that would have been recorded in previous reporting periods if the adjustment to the provisional amounts had been recognized as of the acquisition date.

Effective Date and Transition

For public business entities, the ASU is effective for fiscal years beginning after December 15, 2015, including interim periods therein. For all other entities, the ASU is effective for fiscal years beginning after December 15, 2016, and interim periods within fiscal years beginning after December 15, 2017. The ASU must be applied prospectively to adjustments to provisional amounts that occur after the effective date. Early application is permitted for financial statements that have not been issued.

The only disclosures required at transition will be the nature of and reason for the change in accounting principle. An entity should disclose that information in the first annual period of adoption and in the interim periods within the first annual period if there is a measurement-period adjustment during the first annual period in which the changes are effective.

Simplifying the Transition to the Equity Method of Accounting

The FASB issued ASU 2016-07 in March 2016 as part of its simplification initiative. Under the guidance in U.S. GAAP before the ASU's amendments, an investor that meets the conditions for applying the equity method of accounting is required to retrospectively apply such method to all prior periods in which it had historically accounted for the investment under the cost method or as an AFS security. The ASU removes the requirement to retrospectively apply the equity method of accounting. It also requires entities to recognize unrealized holding gains or losses in accumulated other comprehensive income (AOCI) related to an AFS security that becomes eligible for the equity method of accounting in earnings as of the date the investment qualifies for the equity method of accounting.

The guidance is effective for all entities for fiscal years beginning after December 15, 2016, including interim periods therein. The guidance must be applied prospectively to increases in the level of ownership interest or degree of influence occurring after the ASU's effective date. Early adoption is permitted.

Also as part of its simplification initiative, the FASB issued a proposed ASU in June 2015 that would have eliminated the requirement to separately account for basis differences (i.e., the difference between the cost of an investment and the amount of underlying equity in net assets). The proposed guidance would have also eliminated the requirement for an investor to allocate basis differences to specific assets and liabilities of the investee and account for them accordingly (e.g., additional depreciation for basis differences assigned to tangible assets). However, many commenters on the proposed ASU indicated that eliminating the allocation of basis differences could create different complexities and result in inflated values of investments that would no longer be amortized over time as well as increase the likelihood of impairment in future periods. Accordingly, in May 2016, the FASB decided to remove the project from its agenda because of "insufficient support to change the equity method of accounting."[8]

Thinking It Through

Application of the existing accounting requirements (i.e., before the ASU's amendments) can be particularly onerous because investments are often structured as partnerships or limited liability corporations, which may require use of the equity method at a relatively low ownership percentage. Further, investments in specific securities may evolve over time, depending on investment strategy and portfolio allocation. For public companies, the existing U.S. GAAP requirements have been compounded by the SEC's guidance requiring registrants to provide

[8] Quoted from the Project Update page on the FASB's Web site.

(1) separate or summarized financial statements for prior periods once the equity method of accounting is applied to a significant investment (see paragraph 2405.5 of the SEC's *Financial Reporting Manual*) or (2) retroactively adjusted annual financial statements reflecting the equity method of accounting if a registration statement is filed after the first quarter in which the change to the equity method of accounting is reported but before the next annual report on Form 10-K is filed (see Topic 13 of the *Financial Reporting Manual*).

Accordingly, the ASU provides welcome relief from complex accounting considerations and SEC reporting requirements related to a transition to the equity method of accounting. However, the new ASU will also introduce new complexities after such transition. For example, application of the new method may result in additional basis differences if the earnings that would have affected the cost basis under existing U.S. GAAP are not recognized retrospectively.

Simplifying the Measurement of Inventory

Background

In July 2015, the FASB issued ASU 2015-11, which requires entities to measure most inventory "at the lower of cost and net realizable value," thereby simplifying the current guidance under which an entity must measure inventory at the lower of cost or market ("market" in this context is defined as one of three different measures). The ASU will not apply to inventories that are measured by using either the last-in, first-out (LIFO) method or the retail inventory method (RIM).

Under current guidance (i.e., ASC 330-10-35 before the ASU), an entity subsequently measures inventory at the lower of cost or market, with "market" defined as replacement cost, net realizable value (NRV), or NRV less a normal profit margin. An entity uses current replacement cost provided that it is not above NRV (i.e., the ceiling) or below NRV less an "approximately normal profit margin" (i.e., the floor). The analysis of market under current guidance requires the use of these ceilings and floors and is unnecessarily complex. The ASU eliminates this analysis for entities within the scope of the guidance.

Scope

The ASU applies to entities that recognize inventory within the scope of ASC 330, except for inventory measured under the LIFO or RIM method given certain challenges in applying the lower of cost or NRV approach to those methods.

Key Provisions of the ASU

Under the ASU, inventory is "measured at the lower of cost and net realizable value," which eliminates the need to determine replacement cost and evaluate whether it is above the ceiling (NRV) or below the floor (NRV less a normal profit margin). The ASU defines NRV as the "estimated selling prices in the ordinary course of business, less reasonably predictable costs of completion, disposal, and transportation." The Board did not amend other guidance on measuring inventory (e.g., the first-in, first out (FIFO); LIFO; or average cost method).

Effective Date and Transition

For public business entities, the ASU is effective prospectively for annual periods beginning after December 15, 2016, and interim periods therein. For all other entities, the ASU is effective prospectively for annual periods beginning after December 15, 2016, and interim periods within annual periods beginning after December 15, 2017. Early application of the ASU is permitted. Upon transition, entities must disclose the nature of and reason for the accounting change.

Consolidation — Interests Held Through Related Parties That Are Under Common Control

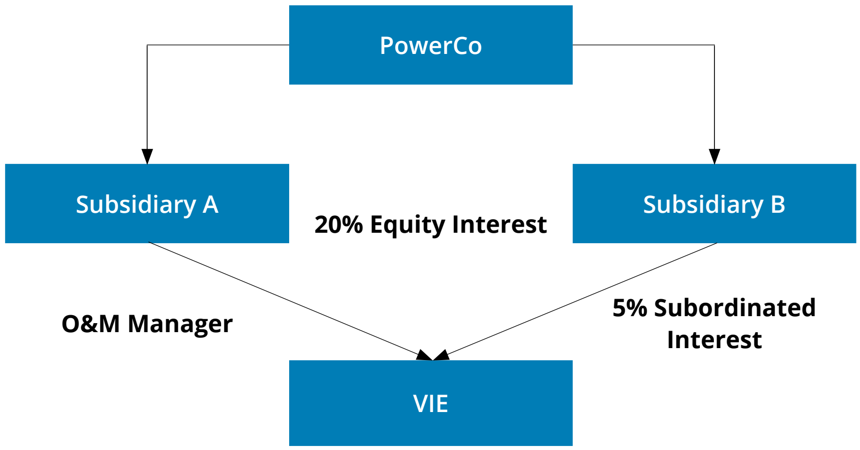
Background

In February 2015, the FASB issued ASU 2015-02, which amends the guidance in ASC 810-10 to require, among other things, a reporting entity that is a single decision maker to consider interests held by its related parties only if the reporting entity has a direct interest in the related parties. If the related parties and the reporting entity are not under common control, the indirect economic interests in a variable interest entity (VIE) held through related parties would be considered on a proportionate basis in the determination of whether the reporting entity is the primary beneficiary of the VIE. Alternatively, if the related parties and the reporting entity are under common control, the reporting entity would be required to consider the interests of the related parties in their entirety (not on a proportionate basis). As a result, the reporting entity may satisfy the "power" criterion (i.e., the ability to direct the activities that most significantly affect the VIE's economic performance) in the consolidation analysis even if it has a relatively insignificant economic interest in the VIE.

In October 2016, the FASB issued ASU 2016-17 to remove the last sentence of ASC 810-10-25-42, which states, "Indirect interests held through related parties that are under common control with the decision maker should be considered the equivalent of direct interests in their entirety." As a result of the ASU, a reporting entity would consider its indirect economic interests in a VIE held through related parties that are under common control on a proportionate basis in a manner consistent with its consideration of indirect economic interests held through related parties that are not under common control.

Example

A limited liability company (VIE) is formed to develop, construct, and operate a wind turbine electric generating facility ("Wind Farm"). The VIE has an operations and maintenance (O&M) manager ("Subsidiary A") that does not hold any ownership interests in the Wind Farm. Another entity ("Subsidiary B") holds a 5 percent interest in the Wind Farm, which represents the most subordinated interest and therefore absorbs more than an insignificant amount of the expected losses of the Wind Farm. Various unrelated investors hold the remaining ownership interests. In addition, A holds a 20 percent ownership interest in B, and both entities are wholly owned subsidiaries of PowerCo. As the O&M manager, A provides labor, equipment, and other services to monitor, maintain, and perform the day-to-day operations of the Wind Farm, and it was determined that the activities related to the day-to-day operations of the Wind Farm are the most significant decisions of the trust.



Under the guidance before ASU 2016-17, A and B must consider their own interests before evaluating which entity is the primary beneficiary of the VIE. Accordingly, A would conclude that it meets the power criterion as well as the "economics" criterion (i.e., the obligation to absorb losses of the VIE that could potentially be significant to the VIE or the right to receive benefits from the VIE that could potentially be significant to the VIE) on its own because A must treat B's subordinated interest in the VIE as its own as a result of A's interest in B, and the entities are under common control of PowerCo.

Under the ASU, A will still conclude that it meets the power criterion on its own. However, in the evaluation of the economics criterion, since A owns a 20 percent interest in B, and B owns a 5 percent subordinated interest in the VIE, A will conclude that it has a 1 percent indirect interest in the VIE as a result of its interest in B (20 percent interest in B multiplied by B's 5 percent interest in the VIE). Therefore, A will be unlikely to meet the economics criterion on its own. However, since A and B are under common control and as a group will satisfy the power and economics criteria, they will need to perform the related-party tiebreaker test to determine which party is most closely associated with the VIE.

Thinking It Through

As a result of the ASU, the related-party tiebreaker test will be performed more frequently because, as illustrated in the example above, it will be less likely for the decision maker to meet the economics criterion on its own when considering its exposure through a related party under common control on a proportionate basis.[9] Many decision makers view the ASU's guidance favorably because they would otherwise consolidate a legal entity with a small indirect interest. The ASU will instead require the decision maker to consider which party (the single decision maker or the related party under common control) is most closely associated with the VIE and

[9] This outcome is because the FASB has proposed to change only the guidance in ASC 810-10-25-42. The Board also considered amending the guidance on determining whether fees paid to a decision maker or service provider represent a variable interest in the evaluation of a decision maker's indirect interests held through related parties under common control. While the proposal would retain that guidance, the Board will consider clarifying it, as well as other aspects of the guidance on common-control arrangements, as part of a separate initiative. The proposal therefore affects only the decision maker's consideration of indirect interests held through related parties under common control in the primary-beneficiary assessment.

therefore should consolidate. This guidance may have a significant impact on the individual financial statements of P&U subsidiaries because it could change which subsidiary consolidates a VIE.

Effective Date and Transition

For all reporting entities, the guidance will be effective for annual periods beginning after December 15, 2016. Reporting entities that have not yet adopted the guidance in ASU 2015-02 will be required to adopt ASU 2016-17's amendments at the same time they adopt those in ASU 2015-02. Early adoption, including adoption in an interim period, is permitted as of October 26, 2016 (the ASU's issuance date).

Employee Share-Based Payment Accounting Improvements

Background

In March 2016, the FASB issued ASU 2016-09, which simplifies several aspects of the accounting for employee share-based payment transactions for both public and nonpublic entities, including the accounting for income taxes, forfeitures, and statutory tax withholding requirements, as well as classification in the statement of cash flows. The new guidance, which is part of the Board's simplification initiative, also contains practical expedients for nonpublic entities.

Key Provisions of the ASU

Accounting for Income Taxes

Under current guidance, when a share-based payment award is granted to an employee, the fair value of the award is generally recognized over the vesting period, and a corresponding DTA is recognized to the extent that the award is tax-deductible. The tax deduction is generally based on the intrinsic value at the time of exercise (for an option) or on the fair value upon vesting of the award (for restricted stock), and it can be either greater (excess tax benefit) or less (tax deficiency) than the compensation cost recognized in the financial statements. All excess tax benefits are recognized in additional paid-in capital (APIC), and tax deficiencies are recognized either in the income tax provision or in APIC to the extent that there is a sufficient "APIC pool" related to previously recognized excess tax benefits.

Under the ASU, an entity recognizes all excess tax benefits and tax deficiencies as income tax expense or benefit in the income statement. This change eliminates the notion of the APIC pool and significantly reduces the complexity and cost of accounting for excess tax benefits and tax deficiencies. In addition, excess tax benefits and tax deficiencies are considered discrete items in the reporting period in which they occur and are not included in the estimate of an entity's annual effective tax rate.

The ASU's guidance on recording excess tax benefits and tax deficiencies in the income statement also has a corresponding effect on the computation of diluted earnings per share when an entity applies the treasury stock method. An entity that applies such method under current guidance estimates the excess tax benefits and tax deficiencies to be recognized in APIC in determining the assumed proceeds available to repurchase shares. However, under the ASU, excess tax benefits and tax deficiencies are excluded from the calculation of assumed proceeds since such amounts are recognized in the income statement. In addition, the new guidance affects the accounting for tax benefits of dividends on share-based payment awards, which will now be reflected as income tax expense or benefit in the income statement rather than as an increase to APIC.

Further, the ASU eliminates the requirement to defer recognition of an excess tax benefit until the benefit is realized through a reduction to taxes payable.

In addition to addressing the recognition of excess tax benefits and tax deficiencies, the ASU provides guidance on the related cash flow presentation. Under existing guidance, excess tax benefits are viewed as a financing transaction and are presented as financing activities in the statement of cash flows. However, there is no cash receipt but only a reduction in taxes payable. Therefore, a reclassification is made in the statement of cash flows to reflect a hypothetical inflow in the financing section and a hypothetical outflow from the operating section.

Under the ASU, excess tax benefits no longer represent financing activities since they are recognized in the income statement; therefore, excess tax benefits are not separate cash flows and should be classified as operating activities in the same manner as other cash flows related to income taxes. Accordingly, the ASU eliminates the requirement to reclassify excess tax benefits from operating activities to financing activities.

Accounting for Forfeitures

The ASU allows an entity to elect as an accounting policy either to continue to estimate the total number of awards for which the requisite service period will not be rendered (as currently required) or to account for forfeitures when they occur. This entity-wide accounting policy election applies only to service conditions; for performance conditions, the entity continues to assess the probability that such conditions will be achieved. An entity must also disclose its policy election for forfeitures.

Thinking It Through

An entity that adopts a policy to account for forfeitures as they occur must still estimate forfeitures when an award is (1) modified (the estimate applies to the original award in the measurement of the effects of the modification) and (2) exchanged in a business combination (the estimate applies to the amount attributed to precombination service). However, the accounting policy for forfeitures will apply to the subsequent accounting for awards that are modified or exchanged in a business combination.

Statutory Tax Withholding Requirements

The ASU modifies the current exception to liability classification of an award when an employer uses a net-settlement feature to withhold shares to meet the employer's minimum statutory tax withholding requirement. Currently, the exception applies only when no more than the number of shares necessary for the minimum statutory tax withholding requirement to be met is repurchased or withheld. The new guidance stipulates that the net settlement of an award for statutory tax withholding purposes would not result, by itself, in liability classification of the award provided that the amount withheld for taxes does not exceed the maximum statutory tax rate in the employees' relevant tax jurisdictions.

Further, to eliminate diversity in practice, the ASU requires that cash payments to tax authorities in connection with shares withheld to meet statutory tax withholding requirements be presented as a financing activity in the statement of cash flows because such payments represent an entity's cash outflow to reacquire the entity's shares.

Thinking It Through

Under current guidance, an entity is required to track the minimum statutory tax withholding requirement applicable to each specific award grantee in each applicable jurisdiction if shares are repurchased or withheld. Under the new guidance, the maximum rate is determined on a jurisdiction-by-jurisdiction basis even if that rate exceeds the highest rate applicable to a specific award grantee. However, the classification exception would not apply to entities that do not have a statutory tax withholding obligation; for such entities, any net settlement for tax withholding would result in a liability-classified award.

In addition, an entity may change the terms of its awards related to net settlement for withholding taxes from the minimum statutory tax rate to a higher rate up to the maximum statutory tax rate. While this change may be made to existing awards, the entity would not be required to account for such a change as a modification. However, this accounting treatment applies only in these narrow circumstances (i.e., solely to change the net-settlement provisions from the minimum statutory tax rate to a higher rate up to the maximum statutory tax rate for statutory tax withholding purposes) and should not be analogized to other situations.

Practical Expedients for Nonpublic Entities

Expected-Term Practical Expedient

The ASU allows nonpublic entities to use the simplified method to estimate the expected term for awards (including liability-classified awards measured at fair value) with service or performance conditions that meet certain requirements. Such entities would apply this practical expedient as follows:

- For awards with only a service condition, nonpublic entities can estimate the expected term as the midpoint between the requisite service period and the contractual term of the award.
- For awards with a performance condition, the estimate of the expected term would depend on whether it is probable that the performance condition will be achieved:
    - If it is probable that the performance condition will be achieved, nonpublic entities can estimate the expected term as the midpoint between the requisite service period and the contractual term.
    - If it is not probable that the performance condition will be achieved, nonpublic entities can estimate the expected term as (1) the contractual term if the award does not contain an explicit service period or (2) the midpoint between the requisite service period and the contractual term if the award does contain an explicit service period.

Intrinsic Value Practical Expedient

The ASU allows nonpublic entities to make a one-time election to switch from fair value measurement to intrinsic value measurement, without demonstrating preferability, for share-based payment awards classified as liabilities.

Nonpublic entities are not allowed to make this election on an ongoing basis after the effective date of the new guidance.

Transition and Related Disclosures

The following table outlines the transition methods for an entity's adoption of ASU 2016-09:

Type	Transition Method
Recognition of excess tax benefits and tax deficiencies (accounting for income taxes)	Prospective
Unrecognized excess tax benefits (accounting for income taxes)	Modified retrospective
Classification of excess tax benefits in the statement of cash flows	Retrospective or prospective
Accounting for forfeitures	Modified retrospective
Classification and statutory tax withholding requirements	Modified retrospective
Classification of employee taxes paid in the statement of cash flows when an employer withholds shares for tax withholding purposes	Retrospective
Nonpublic entity practical expedient for expected term	Prospective
Nonpublic entity practical expedient for intrinsic value	Modified retrospective

Thinking It Through

An entity's prior-year APIC pool is not affected because prior-year excess tax benefits and tax deficiencies have already been recognized in the financial statements, and the recognition of excess tax benefits and tax deficiencies in the income statement is prospective only in the fiscal year of adoption. As a result, there is no reclassification between APIC and retained earnings in the fiscal years before adoption. The modified retrospective transition guidance for taxes applies only to previously unrecognized excess tax benefits outstanding upon adoption of ASU 2016-09 with a cumulative-effect adjustment to retained earnings.

In the period of adoption, entities are required to disclose (1) the nature of and reason for the changes in accounting principle and (2) any cumulative effects of the changes on retained earnings or other components of equity as of the date of adoption.

In addition, because the change in presentation in the statement of cash flows related to excess tax benefits can be applied either prospectively or retrospectively, entities are required to disclose (1) "that prior periods have not been adjusted" if the change is applied prospectively or (2) the "effect of the change on prior periods retrospectively adjusted" if the change is applied retrospectively. For the change in presentation in the statement of cash flows related to statutory tax withholding requirements, entities are required to disclose the "effect of the change on prior periods retrospectively adjusted."

Effective Date

For public business entities, the ASU is effective for annual reporting periods beginning after December 15, 2016, including interim periods therein. For all other entities, the ASU is effective for annual reporting periods beginning after December 15, 2017, and interim periods within annual reporting periods beginning after December 15, 2018.

Early adoption will be permitted in any interim or annual period for which financial statements have not yet been issued or have not been made available for issuance. If early adoption is elected, all amendments in the ASU that apply must be adopted in the same period. In addition, if early adoption is elected in an interim period, any adjustments should be reflected as of the beginning of the annual period that includes that interim period.

Example

Entity A, an SEC registrant, adopts ASU 2016-09 in its third fiscal quarter. Entity A had $50 of excess tax benefits in each quarter in its current fiscal year to date and is not affected by adopting any of the other provisions of ASU 2016-09. In its previously issued financial statements in Form 10-Q, A recognized a total of $100 ($50 in each quarter) of excess tax benefits in APIC. In its third fiscal quarter, the period in which the ASU is adopted, A recognizes $50 of excess tax benefits in its income statement. That is, the quarter-to-date income tax provision will include only the third fiscal quarter excess tax benefits ($50). In addition, the year-to-date income tax provision will include excess tax benefits of $150 to reflect the reversal of the excess tax benefits recognized in APIC for the first two fiscal quarters ($100) and the recognition of those benefits in the income statement in those prior quarters (the $100 in excess tax benefits related to the first and second fiscal quarters are not recognized in the third quarter but are reflected on a recasted basis in the applicable prior quarters). In the quarterly information footnote of its subsequent Form 10-K filing, A will present a schedule reflecting the first and second fiscal quarters' excess tax benefits ($50 each quarter) in the income statement even though these amounts were reported in APIC in previously issued financial statements in Form 10-Q. Finally, A's financial statements in Form 10-Q issued in the year after A's adoption of the ASU will reflect the prior-year quarterly excess tax benefits (i.e., first and second fiscal quarters of the prior year) on a recasted basis in the income statement rather than in APIC.

Classification of Deferred Taxes

Background and Key Provisions

In November 2015, the FASB issued ASU 2015-17, which will require entities to present DTAs and deferred tax liabilities (DTLs) as noncurrent in a classified balance sheet. The ASU simplifies the current guidance, which requires entities to separately present DTAs and DTLs as current and noncurrent in a classified balance sheet.

The project on simplifying the balance sheet presentation of deferred taxes is part of the FASB's simplification initiative.

Under current guidance (ASC 740-10-45-4), entities "shall separate deferred tax liabilities and assets into a current amount and a noncurrent amount. Deferred tax liabilities and assets shall be classified as current or noncurrent based on the classification of the related asset or liability for financial reporting." Stakeholder feedback indicated that the separate presentation of deferred taxes as current or noncurrent provided little useful information to financial statement users and resulted in additional costs to preparers. Therefore, the FASB issued the ASU to simplify the presentation of deferred taxes in a classified balance sheet. Netting of DTAs and DTLs by tax jurisdiction will still be required under the new guidance.

Noncurrent balance sheet presentation of all deferred taxes eliminates the requirement to allocate a valuation allowance on a pro rata basis between gross current and noncurrent DTAs, which constituents had also identified as an issue contributing to complexity in accounting for income taxes.

Thinking It Through

The ASU will align with the current guidance in IAS 12, which requires entities to present DTAs and DTLs as noncurrent in a classified balance sheet.

The example below compares the classification of DTAs and DTLs under current U.S. GAAP with their classification under the new guidance.

Example

Company ABC has a net DTA of $100 million as of December 31, 20X1, as shown in the table below (amounts in millions):

Balance Sheet as of 12/31/X1	
	DTA/(DTL)
Inventory	$ 50
Net operating loss (NOL) carryforward	350
Fixed assets	(300)
Total DTA/(DTL)	$ 100

Company ABC expects that $100 million of the NOL carryforward will be used in the following year. Below are the current and noncurrent classifications of the DTA/(DTL) as of December 31, 20X1 (amounts in millions):

	Current U.S. GAAP		ASU 2015-17	
Description	Current	Noncurrent	Current	Noncurrent
Inventory	$ 50	$ —	$ —	$ 50
NOL carryforward	100	250	—	350
Fixed assets	—	(300)	—	(300)
Total DTA/(DTL)	$ 150	$ (50)	$ 0	$ 100

Effective Date and Transition

The ASU requires the following:

- For public business entities, the ASU will be effective for annual periods beginning after December 15, 2016, and interim periods therein.
- For entities other than public business entities, the ASU will be effective for annual reporting periods beginning after December 15, 2017, and interim reporting periods within annual reporting periods beginning after December 15, 2018.

The Board decided to allow all entities to early adopt the ASU for any interim or annual financial statements that have not been issued. In addition, entities are permitted to apply the amendments either prospectively or retrospectively.

In the period in which the ASU is adopted, an entity will need to disclose "the nature of and reason for the change in accounting principle." If the new guidance is applied prospectively, the entity should disclose that prior balance sheets were not retrospectively adjusted. However, if the new presentation is applied retrospectively, the entity will need to disclose the quantitative effects of the change on the prior balance sheets presented.

Accounting for Income Taxes: Intra-Entity Asset Transfers

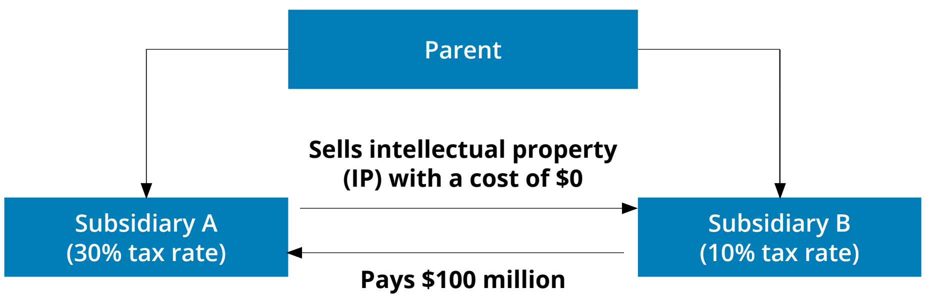
Background

In October 2016, the FASB issued ASU 2016-16, which amends the guidance in ASC 740 to remove the exception that prohibits the immediate recognition of the current and deferred tax effects of intra-entity transfers of assets. The ASU retains the exception specifically for intra-entity asset transfers of inventory. Consequently, in a manner consistent with the current requirements of ASC 740, entities are prohibited from recognizing the current and deferred tax effects of intra-entity transfers of inventory.

For intra-entity transfers of assets other than inventory, the selling (transferring) entity is required to recognize a current tax expense or benefit upon transfer of the asset. Similarly, the purchasing (receiving) entity is required to recognize a DTA or DTL, as well as the related deferred tax benefit or expense, upon receipt of the asset. The purchasing (receiving) entity measures the resulting DTA or DTL by (1) computing the difference between the tax basis of the asset in the buyer's jurisdiction and the financial reporting carrying value of the asset in the consolidated financial statements and (2) multiplying such difference by the enacted tax rate in the buyer's jurisdiction.

The example below compares the income tax accounting for intra-entity transfers of assets other than inventory before and after the ASU.

Example



Before ASU 2016-16

In the transaction above, Subsidiary A recognizes a gain of $100 million on the sale of IP to Subsidiary B, which is equal to the proceeds received ($100 million) less the carrying value of the IP (zero). However, in accordance with ASC 740-10-25-3(e), A is prohibited from recognizing the current tax expense associated with that $100 million gain. Therefore, upon sale, A would record the following journal entry:

Prepaid taxes	30,000,000	
Current taxes payable		30,000,000

Further, B receives a tax basis in the IP of $100 million, which is equal to the amount that it paid to A. This tax basis of $100 million is greater than the carrying value of the IP in the consolidated financial statements (zero), which would generally result in a DTA. However, in accordance with ASC 740-10-25-3(e), B is prohibited from recognizing the DTA (benefit) associated with its tax-over-book basis difference. Therefore, B would not recognize any tax expense (benefit) associated with this transaction.

Example (continued)

After ASU 2016-16

Under the ASU, the exception to recognizing current and deferred taxes on intra-entity transfers of assets is removed (unless the assets are inventory). Therefore, A is required to recognize the current tax expense associated with the gain on the sale of the IP by recording the following journal entry:

Current tax expense	30,000,000	
Current taxes payable		30,000,000

In addition, B is required to recognize the deferred tax effects associated with its purchase of the IP by recording the following journal entry:

DTA	10,000,000	
Deferred tax benefit		10,000,000

For more information on ASU 2016-06, see Deloitte's October 25, 2016, *Heads Up*.

Transition Method

Entities will adopt the new guidance on a modified retrospective basis with a cumulative-effect adjustment directly to retained earnings as of the beginning of the year of adoption. Because the period of adoption is not comparable with the prior periods presented, entities will need to disclose the effects of the accounting change on the financial statements of the period of adoption.

Effective Date and Early Adoption

The guidance in the ASU is effective for public business entities for annual periods beginning after December 15, 2017, including interim periods therein. For other entities, the amendments are effective for annual periods beginning after December 15, 2018, and interim periods within annual periods beginning after December 15, 2019. Early adoption is permitted for all entities as of the beginning of a fiscal year for which neither the annual nor interim (if applicable) financial statements have been issued.

Statement of Cash Flows: Classification of Certain Cash Receipts and Cash Payments

Background

In August 2016, the FASB issued ASU 2016-15, which amends ASC 230 to add or clarify guidance on the classification of certain cash receipts and payments in the statement of cash flows. ASC 230 lacks consistent principles for evaluating the classification of cash payments and receipts in the statement of cash flows. This has led to diversity in practice and, in certain circumstances, financial statement restatements. Therefore, the FASB issued the ASU with the intent of reducing diversity in practice with respect to eight types of cash flows.

Key Provisions of the ASU

The ASU is a result of consensuses reached by the EITF on issues related to the eight types of cash flows. Key provisions of the amendments are summarized below.

Cash Flow Issues	Amendments
Debt prepayment or debt extinguishment costs	Cash payments for debt prepayment or extinguishment costs (including third-party costs, premiums paid, and other fees paid to lenders) must "be classified as cash outflows for financing activities."
Settlement of zero-coupon bonds	The cash outflows for the settlement of a zero-coupon bond must be bifurcated into operating and financing activities. The portion of the cash payment related to accreted interest should be classified in operating activities, while the portion of the cash payment related to the original proceeds (i.e., the principal) should be classified in financing activities.
Contingent consideration payments made after a business combination	Contingent consideration payments that were not made soon after a business combination (on the basis of the consummation date) must be separated and classified in operating and financing activities. Cash payments up to the amount of the contingent consideration liability recognized as of the acquisition date, including any measurement-period adjustments, should be classified in financing activities, while any excess cash payments should be classified in operating activities.
Proceeds from the settlement of insurance claims	Cash proceeds from the settlement of insurance claims should be classified on the basis of the nature of the loss. For insurance proceeds received in a lump-sum settlement, an entity should determine the classification on the basis of the nature of each loss included in the settlement.
Proceeds from the settlement of corporate-owned life insurance (COLI) policies and bank-owned life insurance (BOLI) policies	Cash proceeds from the settlement of COLI and BOLI policies must be classified in investing activities. However, an entity is permitted, but not required, to align the classification of premium payments on COLI and BOLI policies with the classification of COLI and BOLI proceeds (i.e., payments for premiums may be classified as investing, operating, or a combination thereof).
Distributions received from equity method investees	An entity is required to make an accounting policy election to classify distributions received from equity method investees under either of the following methods: • *Cumulative-earnings approach* — Under this approach, distributions are presumed to be returns on investment and classified as operating cash inflows. However, if the cumulative distributions received, less distributions received in prior periods that were determined to be returns of investment, exceed the entity's cumulative equity in earnings, such excess is a return of capital and should be classified as cash inflows from investing activities. • *Nature of the distribution approach* — Under this approach, each distribution is evaluated on the basis of the source of the payment and classified as either operating cash inflows or investing cash inflows. If an entity whose chosen policy is the nature of the distribution approach cannot apply the approach because it does not have enough information to determine the appropriate classification (i.e., the source of the distribution), the entity must apply the cumulative-earnings approach and report a change in accounting principle on a retrospective basis. The entity is required to disclose that a change in accounting principle has occurred as a result of the lack of available information as well as the information required under ASC 250-10-50-2, as applicable. The amendments do not address equity method investments measured under the fair value option.

(Table continued)

Cash Flow Issues	Amendments
Beneficial interests in securitization transactions	A transferor's beneficial interests received as proceeds from the securitization of an entity's financial assets must be disclosed as a noncash activity. Subsequent cash receipts of beneficial interests from the securitization of an entity's trade receivables must be classified as cash inflows from investing activities.
Separately identifiable cash flows and application of the predominance principle	The guidance provides a three-step approach for classifying cash receipts and payments that have aspects of more than one class of cash flows: 1. An entity should first apply specific guidance in U.S. GAAP, if applicable. 2. If there is no specific guidance related to the cash receipt or payment, an entity should bifurcate the cash payment or receipt into "each separately identifiable source or use [of cash] on the basis of the nature of the underlying cash flows." Each separately identifiable source or use of cash will be classified as operating, investing, or financing activities by applying the guidance in ASC 230. 3. If the cash payment or receipt cannot be bifurcated, the entire payment or receipt should be classified as operating, investing, or financing activities on the basis of the activity that is likely to be the predominant source or use of cash.

Thinking It Through

The FASB's objective in the ASU is to eliminate the diversity in practice related to the classification of certain cash receipts and payments. As a result, there could be significant changes for some entities under the revised guidance, particularly with respect to the issues discussed below.

Settlement of Zero-Coupon Bonds

The lack of guidance on the classification of payments to settle zero-coupon bonds in the statement of cash flows has led to diversity in the classification of the cash payment made by a bond issuer at the settlement of a zero-coupon bond. Some entities bifurcate the settlement payment between the principal (the amount initially received by the entity) and accreted interest. In those situations, the portion of the repayment related to principal is classified in financing activities, and the portion related to accreted interest is classified in operating activities. However, other entities do not bifurcate the settlement payment between principal and accreted interest and present the entire repayment in financing activities.

Under the ASU, entities are required to bifurcate the repayment of zero-coupon bonds into principal and accreted interest, with the principal portion classified in financing activities and the accreted interest portion classified in operating activities. As a result, entities that currently classify the entire repayment of zero-coupon bonds in financing activities will need to identify the portion of such payments that are related to accreted interest and apply the provisions of the ASU accordingly.

Distributions Received From Equity Method Investees

While ASC 230 distinguishes between returns of investment (which should be classified as inflows from investing activities) and returns on investment (which should be classified as inflows from operating activities), it does not prescribe a method for differentiating between the two. With respect to distributions from equity method investees, entities make this determination by applying a cumulative-earnings approach or a nature of the distribution approach. The ASU formalizes each of these methods and allows an entity to choose either one as an accounting policy election.

However, the ASU requires entities that choose the nature of the distribution approach to report a change in accounting principle if the information required under this approach is unavailable with respect to a particular investee. Therefore, while the ASU will not eliminate diversity in practice, entities that are currently applying the nature of the distribution approach should be mindful of the additional information and disclosure requirements under the ASU in electing a method as their accounting policy.

Separately Identifiable Cash Flows and Application of the Predominance Principle

ASC 230 acknowledges that certain cash inflows and outflows may have characteristics of more than one cash flow class (e.g., financing, investing, or operating) and states that the "appropriate classification shall depend on the activity that is likely to be the predominant source of cash flows for the item." Although ASC 230 gives examples illustrating the application of the predominance principle, entities often have difficulty applying the guidance.

As a result, when cash flows have aspects of more than one cash flow class, the ASU requires that entities first determine the classification of those cash receipts and payments by applying the specific guidance in ASC 230 and other applicable ASC topics. Further, the ASU notes that "[i]n the absence of specific guidance, a reporting entity shall determine each separately identifiable source or each separately identifiable use within the cash receipts and cash payments on the basis of the nature of the underlying cash flows." The ASU goes on to observe that "[i]n situations in which cash receipts and payments have aspects of more than one class of cash flows and cannot be separated by source or use . . . the appropriate classification shall depend on the activity that is likely to be the predominant source or use of cash flows for the item." However, because the ASU does not define the term "separately identifiable" in this context, we believe that challenges may be presented related to identifying separately identifiable cash receipts and payments as well as applying the term "predominant."

Effective Date and Transition

For public business entities, the guidance is effective for fiscal years beginning after December 15, 2017, including interim periods therein. For all other entities, it is effective for fiscal years beginning after December 15, 2018, and interim periods within fiscal years beginning after December 15, 2019. Early adoption will be permitted for all entities.

Entities must apply the guidance retrospectively to all periods presented but may apply it prospectively if retrospective application would be impracticable.

Going Concern

Background

In August 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.

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

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.

If an entity triggers the substantial-doubt threshold, its footnote disclosures must contain the following information, as applicable:

Substantial Doubt Is Raised but Is Alleviated by Management's Plans	Substantial Doubt Is Raised but Is Not Alleviated
• Principal conditions or events. • Management's evaluation. • Management's plans.	• Principal conditions or events. • Management's evaluation. • Management's plans. • Statement that there is "substantial doubt about [the] entity's ability to continue as a going concern."

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.

Restricted Cash

Background

In November 2016, the FASB issued ASU 2016-18, which amends ASC 230 to clarify guidance on the classification and presentation of restricted cash. The ASU is the result of the following consensuses reached by the EITF:

- An entity should include in its cash and cash-equivalent balances in the statement of cash flows those amounts that are deemed to be restricted cash and restricted cash equivalents. The Task Force decided not to define the terms "restricted cash" and "restricted cash equivalents" but observed that an entity should continue to provide appropriate disclosures about its accounting policies pertaining to restricted cash in accordance with other GAAP. The Task Force also observed that any change in accounting policy will need to be assessed under ASC 250.
- A reconciliation between the statement of financial position and the statement of cash flows must be disclosed when the statement of financial position includes more than one line item for cash, cash equivalents, restricted cash, and restricted cash equivalents.
- Changes in restricted cash and restricted cash equivalents that result from transfers between cash, cash equivalents, and restricted cash and restricted cash equivalents should not be presented as cash flow activities in the statement of cash flows.
- An entity with a material balance of amounts generally described as restricted cash and restricted cash equivalents must disclose information about the nature of the restrictions.

For additional information about the restricted cash ASU, see Deloitte's November 17, 2016, *Heads Up*.

Effective Date and Transition

For public business entities, the guidance is effective for fiscal years beginning after December 15, 2017, including interim periods therein. For all other entities, it is effective for annual periods beginning after December 15, 2018, and interim periods beginning after December 15, 2019. Early adoption of the guidance in the ASU is permitted. A reporting entity will apply the guidance retrospectively.

Clarifying the Definition of a Business

Background

In January 2017, the FASB issued ASU 2017-01 related to the first phase of its project on the definition of a business. The standard is in response to concerns that the current definition of a business has been interpreted too broadly and that many transactions are accounted for as business combinations when they are more akin to asset acquisitions. The standard's key provisions are discussed below. For more information, see Deloitte's related *Heads Up*, which will be issued after this publication goes to press.

The standard does the following:

- Provides a screen to determine when a set of assets and activities ("set") is not a business. The screen requires that when substantially all of the fair value of the gross assets acquired (or disposed of) is concentrated in a single identifiable asset or a group of similar identifiable assets, the set is not a business. The screen will reduce the number of transactions that need to be evaluated to determine whether they are business combinations or asset acquisitions.

- Requires that if the screen's criteria are not met, the set must include an input and a substantive process that together significantly contribute to the ability to create outputs. The standard also provides a framework to assist entities in the evaluation of whether both an input and a substantive process are present.
- Narrows the definition of the term "output" to be consistent with that in ASC 606.

Screen for Single Assets or Group of Similar Identifiable Assets

Under the ASU, a single identifiable asset would include (1) a tangible asset that is attached to and cannot be physically removed and used separately from another tangible asset (e.g., land and building) and (2) in-place lease intangible assets and the related leased assets. When evaluating whether assets are similar, an entity should consider the nature of each single identifiable asset and the risks associated with managing and creating outputs from the assets (i.e., the risk characteristics).

Thinking It Through

The standard specifies certain assets that cannot be considered similar, such as a financial asset and a nonfinancial asset (e.g., customer deposits and customer relationships) and different major classes of financial assets (e.g., accounts receivable and marketable securities). In addition, identifiable assets within the same major asset class that have significantly different risk characteristics cannot be combined.

If the screen's criteria are not met, the entity would apply the ASU's framework for evaluating whether an input and a substantive process are both present and, if so, whether they together significantly contribute to the ability to produce outputs.

Input and Substantive Process Requirement

As noted above, the standard provides a framework for determining whether a set has an input and a substantive process that together significantly contribute to the ability to create outputs. When a set does not yet have outputs, the set would have a substantive process only if it has an organized workforce that has the necessary skills, knowledge, or experience to perform an acquired process (or group of processes) that, when applied to an acquired input or inputs, is critical to the ability to continue producing outputs. For a set with outputs, the FASB introduced less stringent criteria for determining whether the set has a substantive process. An organized workforce may represent a substantive process. However, a set may have a substantive process even without an organized workforce if it includes (1) an acquired contract that provides access to an organized workforce or (2) an acquired process or processes that contribute to the ability to continue producing outputs and cannot be replaced without significant cost, effort, or delay or are considered unique or scarce.

Definition of Output

Under current guidance, an output is defined as the "result of inputs and processes applied to those inputs that provide or have the ability to provide a return in the form of dividends, lower costs, or other economic benefits directly to investors or other owners, members, or participants." The ASU changes this definition to the "result of inputs and processes applied to those inputs that provide goods or services to customers, investment income (such as dividends or interest), or other revenues." The revised definition of outputs aligns the definition with the new revenue guidance in ASC 606.

Effective Date and Transition

The standard is effective for public business entities for annual periods beginning after December 15, 2017, including interim periods. For all other entities, the standard is effective for annual periods beginning after December 15, 2018, and interim periods beginning after December 15, 2019. Early adoption is permitted for transactions (i.e., acquisitions or dispositions) that occurred before the issuance date or effective date of the standard, but only if the transactions have not been reported in financial statements that have been issued or made available for issuance.

Thinking It Through

Within the P&U industry, acquisitions of power plants and other generating assets (which are not considered in-substance real estate) have generally been accounted for as business combinations under the current guidance. However, under the standard, fewer acquisitions will qualify as business combinations.

Further, acquisitions such as those of proven gas reserves would need to be evaluated under the new guidance to determine whether the set includes a substantive process. The energy and resources industry as a whole, including P&U entities, should consider the amendments to the definition of a business as described above and continue to monitor the second and third phases of the project and their potential effects on the industry.

Alternatives for Private Companies

Changes to Effective Date and Transition Guidance in Certain Private-Company ASUs

In March 2016, the FASB issued ASU 2016-03, which gives private companies a one-time unconditional option to forgo a preferability assessment the first time they elect a Private Company Council (PCC) accounting alternative within the ASU's scope. However, private companies would still be required to perform a preferability assessment in accordance with ASC 250 for any subsequent change to their accounting policy election in a manner consistent with all accounting policy changes under ASC 250.

The ASU also eliminates the effective dates of PCC accounting alternatives that are within the ASU's scope and extends the transition guidance for such alternatives indefinitely. The new guidance is effective immediately and affects all private companies within the scope of ASU 2014-02 (goodwill), ASU 2014-03 (derivatives and hedging), ASU 2014-07 (common-control leasing arrangements), and ASU 2014-18 (identifiable intangible assets). While the new standard extends the transition guidance in ASU 2014-07 (VIEs) and ASU 2014-18, it does not change the manner in which such guidance is applied. See Deloitte's March 16, 2016, *Heads Up* for more information.

Other Private-Company Matters

Throughout 2016, the PCC has discussed aspects of financial reporting that are complex and costly for private companies, including the application of VIE guidance to common-control arrangements, balance-sheet classification of debt, and liabilities and equity short-term improvements. During its April 2016 meeting, the PCC voted to recommend that the FASB add to its agenda PCC Issue 15-02, "Applying Variable Interest Entity Guidance to Entities Under Common Control."

Section 5 — New Accounting Guidance on the Horizon

Financial Instruments

Hedging

In September 2016, the FASB issued a proposed ASU that would amend the hedge accounting recognition and presentation requirements of ASC 815 to (1) reduce their complexity and simplify their application by preparers and (2) improve the transparency and understandability of information conveyed to financial statement users about an entity's risk management activities by better aligning those activities with the entity's financial reporting for hedging relationships.

Although the changes proposed by the FASB are significant, constituents also should take note of those aspects of existing hedge accounting that the Board decided to retain. The proposal still would require all hedging relationships to be highly effective. Moreover, an entity would retain the ability to voluntarily dedesignate a hedging relationship, designate certain component risks of the hedged item as the hedged risk, and apply the critical-terms-match method or the shortcut method.

The FASB will determine the effective date of the proposed amendments after it considers constituent feedback; however, it has tentatively determined that earlier application of the proposed amendments will be permitted at the beginning of any fiscal year before the effective date. Comments on the proposal were due by November 22, 2016.

The sections below summarize the proposed ASU's key provisions. For additional information about the proposed ASU, see Deloitte's September 14, 2016, *Heads Up*.

Key Proposed Changes to the Hedge Accounting Model

Hedge Documentation and Qualitative Assessments of Hedge Effectiveness

Under the proposed model, an entity would be required to perform an initial prospective quantitative assessment of hedge effectiveness at hedge inception (unless the hedging relationship qualifies for application of one of the expedients that permit an assumption of perfect hedge effectiveness, such as the shortcut method or critical-terms-match method); however, the entity generally would have until its first quarterly hedge effectiveness assessment date (i.e., up to three months) to complete this quantitative assessment. All other hedge documentation still would need to be in place at hedge inception. The entity could elect to perform subsequent prospective and retrospective hedge effectiveness assessments qualitatively if certain criteria are satisfied; however, the entity could be forced to revert to quantitative assessments if, because facts and circumstances have changed, the entity may no longer assert qualitatively that the hedging relationship was and continues to be highly effective. Once an entity is forced to perform a quantitative assessment, it would be prohibited from performing qualitative assessments in future periods.

Cash Flow Hedges of Forecasted Purchases or Sales of Nonfinancial Items

For a forecasted purchase or sale of a nonfinancial item, the proposed model would permit an entity to designate the variability in cash flows attributable to changes in a contractually specified component as the hedged risk if certain criteria are satisfied. An entity could also hedge exposures arising from a contractually specified component of an agreement to purchase or sell a nonfinancial item for a period that extends beyond the contractual term or when a contract does not yet exist if the qualifying criteria will be met in a future contract and all the other cash flow hedging requirements are met.

Thinking It Through

The FASB's proposed decision to permit entities to hedge risks from contractually specified components of nonfinancial items represents a significant change from existing U.S. GAAP and may especially affect P&U entities. For example, under the proposed guidance, a P&U entity with a commodity exposure at a given delivery point may be able to hedge only the price risk associated with price volatility at a liquid trading hub instead of the entire exposure from the contract.

Recognition and Presentation of the Effects of Hedging Instruments

The proposed amendments would eliminate the concept of separately recognizing periodic hedge ineffectiveness (although under the mechanics of fair value hedging, economic ineffectiveness would still be reflected in current earnings for those hedges).

For highly effective fair value hedging relationships, all changes in the fair value of the hedging instrument, including any amounts excluded from the assessment of hedge effectiveness, would be recorded in current earnings in the same income statement line as the earnings effect of the hedged item.

For highly effective cash flow hedging relationships, the change in the fair value of the hedging instrument used to assess hedge effectiveness would initially be recorded in OCI and would be reclassified out of AOCI into earnings and presented in the same income statement line as the earnings effect of the hedged item when the hedged item affects earnings. Any amounts excluded from the assessment of hedge effectiveness would be recognized immediately in earnings in the same income statement line as the earnings effect of the hedged item. Further, an entity would immediately reclassify out of AOCI amounts associated with any hedged forecasted transaction whose occurrence is not probable. Such amounts would be presented in current earnings in the same income statement line in which the earnings effect of the hedged item would have been recorded had the hedged forecasted transaction occurred.

For highly effective net investment hedges, the change in the fair value of the hedging instrument used to assess hedge effectiveness would initially be recorded in the cumulative translation adjustment in OCI. When the hedged net investment affects earnings (i.e., upon a sale or liquidation), amounts would be reclassified out of the cumulative translation adjustment and be presented in the same income statement line in which the earnings effect of the net investment is presented. The portion (if any) of the hedging instrument's change in fair value that is excluded from the hedge effectiveness assessment would be recognized immediately in income (although the income statement presentation would not be prescribed).

Financial Hedging Relationships

For hedges of financial items, the proposed model (1) allows the contractually specified index rate in a variable-rate hedged item to be the designated interest rate risk, (2) retains the existing benchmark interest rate definition for fixed-rate hedged items with minor modifications to eliminate inconsistencies, and (3) designates the SIFMA Municipal Swap index as a permitted benchmark interest rate.

Fair Value Hedges of Interest Rate Risk

Under the proposal, for a fair value hedge of interest rate risk, an entity would be allowed to:

- Designate the change in only the benchmark component of total coupon cash flows attributable to changes in the benchmark interest rate as the hedged risk in a hedge of a fixed-rate financial asset or liability. However, if the current market yield of the hedged item is less than the benchmark interest rate at hedge inception (i.e., a "sub-benchmark" hedge), the entity would be required to use the total contractual coupon cash flows for its calculation.

- Consider, for prepayable financial instruments, only how changes in the benchmark interest rate affect a decision to settle a debt instrument before its scheduled maturity in calculating the change in the fair value of the hedged item attributable to interest rate risk.
- Designate as the hedged risk only a portion of the hedged item's term and measure the change in the fair value of the hedged item attributable to changes in the benchmark interest rate by "using an assumed term that begins with the first hedged cash flow and ends with the last hedged cash flow." The hedged item's assumed maturity would be the date on which the last hedged cash flow is due and payable.

Shortcut Method and Critical-Terms-Match Method

The proposal would retain both the shortcut and critical-terms-match methods and provide additional relief for entities applying those methods. It would amend the shortcut accounting requirements to allow an entity to specify, at the inception of the hedging relationship, the quantitative (long-haul) method it will use to assess hedge effectiveness and measure hedge results if it later determines that application of the shortcut method was not or no longer is appropriate. In addition, the proposal would amend certain shortcut-method criteria to allow partial-term fair value hedges to qualify for the shortcut method.

Further, the proposal would expedite an entity's ability to apply the critical-terms-match method to cash flow hedges of groups of forecasted transactions. If all other critical-terms-match criteria were satisfied, such hedges would qualify for the critical-terms-match method if all the forecasted transactions occurred within 31 days of the hedging derivative's maturity.

Disclosure Requirements

The proposed ASU would add new disclosure requirements and amend existing ones. Also, to align the disclosure requirements with the proposed changes to the hedge accounting model, the proposal would remove the requirement for entities to disclose amounts of hedge ineffectiveness. In addition, an entity would be required to provide:

- Tabular disclosure of (1) the total amounts reported in the statement of financial performance for each income and expense line item that is affected by hedging and (2) the effects of hedging on those line items.
- Disclosures about the carrying amounts and cumulative basis adjustments of items designated and qualifying as hedged items in fair value hedges.
- Qualitative disclosures describing (1) quantitative hedging goals, if any, established in developing its hedging objectives and strategies and (2) whether those goals were met.

These disclosures would be required for every annual and interim reporting period for which a statement of financial position and statement of financial performance are presented.

Adoption and Transition

Entities would adopt the proposal's provisions by applying a modified retrospective approach to existing hedging relationships as of the adoption date. After adoption, in all interim and annual periods, entities would begin to apply the new accounting and presentation model and provide the new and amended disclosures.

In each annual and interim reporting period in the fiscal year of adoption, entities would also be required to furnish certain disclosures required by ASC 250 about (1) the nature and reason for the change in accounting principle and (2) the cumulative effect of the change on the components of equity or net assets as of the date of adoption.

The proposal also describes (1) specific transition considerations related to the accounting for fair value hedges of interest rate risk, (2) one-time transition elections that allow entities to amend the documentation for existing hedging relationships and to take advantage of the guidance on qualitative assessments and the shortcut method of accounting, and (3) a one-time transition election that allows entities, for certain existing cash flow hedging relationships, to take advantage of the amendments that permit designation of a contractually specified interest rate (for variable-rate instruments) or a contractually specified component (for forecasted purchases or sales of nonfinancial items).

Thinking It Through

P&U entities should carefully analyze the proposed ASU to assess its possible ramifications on their hedging strategies, systems, and internal controls. Multinational companies should note that the FASB's proposed hedging model is likely to differ significantly from the IASB's IFRS 9 hedging model.

Liabilities and Equity — Targeted Improvements

Background

In this project, the Board decided to proceed with making targeted improvements related to two narrow issues and issued a proposed ASU on December 7, 2016 (comments are due by February 6, 2017).

The proposed changes would affect the guidance in U.S. GAAP on:

- The accounting for instruments with "down-round" provisions.
- The indefinite deferral of certain pending content in ASC 480-10.

Down-Round Provisions

Background

A down-round provision is a term in an equity-linked financial instrument (e.g., a freestanding warrant contract or an equity conversion feature embedded within a host debt or equity contract) that triggers a downward adjustment to the instrument's strike price (or conversion price) if the entity issues equity shares at a lower price (or equity-linked financial instruments with a lower strike price) than the instrument's then-current strike price. The purpose of the feature is to protect the instrument's counterparty from future issuances of equity shares at a more favorable price.

Under current U.S. GAAP, a contract (or embedded equity conversion feature) that contains a down-round provision does not qualify as equity because such arrangement precludes a conclusion that the contract is indexed to the entity's own stock under ASC 815-40-15 (as illustrated in ASC 815-40-55-33 and 55-34). As a result, contracts and features that include down-round provisions do not currently qualify for the scope exception to derivative accounting in ASC 815-10 for contracts that are indexed to, and classified in, stockholders' equity. Therefore, freestanding contracts on an entity's own equity that contain a down-round feature and meet the definition of a derivative (including net settlement) are accounted for at fair value with changes in fair value recognized in earnings. Similarly, features embedded in an entity's own equity that contain down-round provisions must be separated and accounted for as derivative instruments at fair value if they meet the bifurcation criteria in ASC 815-15.

Proposed Changes

The proposed changes would apply to issuers of financial instruments (e.g., a warrant or a convertible instrument) with down-round features. Specifically excluded from the scope would be (1) freestanding financial instruments and embedded conversion options that are accounted for at fair value with changes in fair value recognized in earnings (e.g., freestanding and bifurcated embedded derivative instruments within the scope of ASC 815 and debt for which the issuer has elected the fair value option in ASC 825-10) and (2) convertible debt instruments that are separated into liability and equity components (e.g., convertible debt with beneficial conversion features or cash conversion features pursuant to ASC 470-20).

Under the proposed approach, a down-round provision would not preclude an entity from concluding that the instrument or feature that includes the provision is indexed to the entity's own stock. For example, when an entity evaluates whether it is required to classify a freestanding warrant that gives the counterparty the right to acquire the entity's common stock as a liability or equity under ASC 815-40, the existence of the down-round feature would not affect the analysis. If the warrant otherwise meets the condition for equity classification, it would be classified as equity. Similarly, in the analysis of whether an embedded conversion feature in a debt host contract must be bifurcated as an embedded derivative under ASC 815-15, the existence of a down-round provision would not prevent the contract from qualifying for the scope exception in ASC 815-10-15-74 for contracts indexed to an entity's own stock and classified in stockholders' equity.

While instruments that contain down-round features would no longer be expressly precluded from equity classification, such instruments may still not qualify for equity classification for other reasons (e.g., if the issuer could be forced to net cash settle the contract). The classification of instruments as liabilities or equity would not, under the proposal, be dictated by the down-round feature. Instead, the down-round feature would affect the accounting only if it were "triggered" (i.e., the entity issued shares at a price below the strike price). Once the feature was triggered, entities would determine the value that was transferred to the holder when the price adjustment occurred.

Thinking It Through

Under current U.S. GAAP, down-round protection often results in instruments' being accounted for as liabilities, with changes in fair value recorded through earnings. Under the proposed changes, fewer instruments are expected to require such classification and resulting fair value treatment. However, many instruments or embedded features are precluded from equity classification because of the existence of other terms (e.g., warrants on contingently redeemable preferred stock) and would therefore be unaffected by this proposed change.

Further, entities that present fair value financial statements (e.g., in accordance with ASC 946) would be largely unaffected by this change.

Removal of the Indefinite Deferral Under ASC 480

The transition guidance in ASC 480-10 indefinitely defers the application of some of its requirements for certain instruments and entities (i.e., certain mandatorily redeemable financial instruments of nonpublic entities that are not SEC registrants and certain mandatorily redeemable noncontrolling interests). Accordingly, such instruments may qualify as equity under U.S. GAAP even though ASC 480-10-25 suggests that they should be classified as liabilities.

ASC 480-10 requires issuers to classify mandatorily redeemable financial instruments as liabilities. Because of the indefinite deferral noted above, these requirements are labeled "pending content" in the Codification, but the transition guidance in ASC 480-10-65 provides no effective date for them.

Therefore, the transition requirements under the proposed guidance would effectively provide scope exceptions for parts of the guidance in ASC 480-10 for affected entities and instruments.

Simplifying the Balance Sheet Classification of Debt

Background

The FASB recently directed its staff to draft a proposed ASU that would simplify the classification of debt as either current or noncurrent on the balance sheet. The guidance currently in ASC 470-10 consists of an assortment of fact-specific rules and exceptions, the application of which varies according to the terms and conditions of the debt arrangement, management's expectations of when debt may be settled or refinanced, and certain post-balance-sheet events. The objective of the project is to reduce the cost and complexity of applying this guidance while maintaining or improving the usefulness of the information provided to financial statement users.

Principles-Based Approach

The FASB's tentative approach would replace the current, fact-specific guidance with a unified principle for determining the classification of a debt arrangement in a classified balance sheet as either current or noncurrent. Specifically, an entity would classify a debt arrangement as noncurrent if *either* of the following criteria is met as of the financial reporting date:[1]

- "The liability is contractually due to be settled more than 12 months (or operating cycle, if longer) after the balance sheet date."
- "The entity has a contractual right to defer settlement of the liability for at least 12 months (or operating cycle, if longer) after the balance sheet date."

As an exception to this classification principle, debt that is due to be settled within 12 months as a result of a covenant violation as of the balance sheet date would be classified as noncurrent if the debtor receives a waiver that meets certain conditions after the balance sheet date (see Covenant Violations below).

Scope

The FASB has tentatively decided to clarify that the balance sheet classification guidance in ASC 470-10 applies not only to nonconvertible debt arrangements but also to convertible debt and to mandatorily redeemable financial instruments that are classified as liabilities under ASC 480-10.

Short-Term Obligations Expected to Be Refinanced on a Long-Term Basis

Under current guidance, entities that have the intent and ability to refinance a short-term obligation on a long-term basis after the financial reporting date — as indicated by the post-balance-sheet-date issuance of a long-term obligation, equity securities, or a qualifying refinancing agreement — are required to present the obligation as a noncurrent liability as of the financial reporting date. The tentative approach, however, would require such short-term obligations to be classified within current liabilities because the refinancing of debt after the financial reporting date would be viewed as a new transaction that should not be retroactively reflected in the balance sheet as of that date.

[1] Quoted text is from the FASB's summary of tentative Board decisions reached at its January 28, 2015, meeting.

Subjective Acceleration Clauses and Debt Covenants

Under existing GAAP, the classification of long-term obligations depends in part on whether they are governed by subjective acceleration clauses (SACs) for which exercise is probable (e.g., because of recurring losses or liquidity problems). Under the Board's tentative approach, however, SACs and covenants within long-term obligations would affect the classification of long-term obligations only when triggered or violated, in which case disclosure of the SAC or covenant would be required.

Thinking It Through

Under the Board's tentative approach, some liabilities that are now classified as noncurrent would be classified as current, and vice versa. For example, as a result of the proposed change to the treatment of the refinancing of short-term obligations, an entity would not be allowed to consider refinancing events after the financial reporting date but before the financial statements were issued. Thus, such debt obligations would be classified as current liabilities as of the financial reporting date. Entities should consider the timing of refinancing plans and the potential effect on the classification of short-term obligations.

Covenant Violations

Under current guidance, if the creditor can demand the repayment of a long-term obligation as of the financial reporting date because of the debtor's violation of a debt covenant, the corresponding debt obligation is classified as noncurrent if the debtor obtains a covenant waiver before the date the financial statements are issued and certain other conditions are met. While the Board's tentative approach would retain similar guidance, it would classify such debt as current if the waiver results in the debt's being accounted for as having been extinguished. Because debt extinguishment accounting treats the debt as a newly issued instrument, the original debt obligation, as of the balance sheet date, should be classified within current liabilities since the debtor could demand repayment as of that date.

At its October 19, 2016, meeting, the Board decided to clarify the application of the probability assessment that is associated with the waiver exception. Entities would be required to assess whether a violation of any other covenant not covered by the waiver is probable within 12 months from the reporting date. If so, the related debt would need to be classified as current.

Presentation and Disclosure

Under the Board's tentative approach, debt that is classified as noncurrent in accordance with the exception for debt covenant waivers would be presented separately in the balance sheet. Further, as previously noted, the tentative approach would require entities to disclose information about debt covenants and SACs upon violation or trigger.

Effective Date and Transition

The Board will determine an effective date for the guidance after it considers feedback on the proposed ASU. Once finalized, the proposed approach will be applicable on a prospective basis to debt that exists as of the effective date. Early adoption will be permitted.

Next Steps

The proposed ASU is expected to be released in early January 2017. The comment period is expected to end no earlier than May 5, 2017.

Goodwill and Business Combinations

Subsequent Accounting for Goodwill for Public Business Entities and Not-for-Profit Entities, Including Goodwill Impairment

Background

In November 2013, the FASB endorsed (and later issued guidance on[2]) a decision by the PCC to give nonpublic business entities an accounting alternative under which they can elect to amortize goodwill and perform a simplified impairment test. The Board received feedback on the PCC accounting alternative indicating that many public business entities and not-for-profit entities had similar concerns about the cost and complexity of the annual goodwill impairment test.

In response, the Board in 2014 added to its agenda a goodwill simplification project that would be completed in two phases. The Board later separated the undertaking into two individual projects: (1) accounting for goodwill impairment and (2) subsequent accounting for goodwill for public business entities and not-for-profit entities. However, in October 2016, the Board decided to suspend deliberations on this phase of the project and move it to the research agenda. The FASB is also evaluating the effectiveness of the changes to the accounting for goodwill impairment (Phase 1) in meeting the Board's objective. In addition, the Board is continuing to monitor the IASB's projects on goodwill.

Current Status

Under ASC 350, impairment of goodwill "is the condition that exists when the carrying amount of goodwill exceeds its implied fair value." The implied fair value of goodwill is determined in the same manner as the amount of goodwill recognized in a business combination. The process of measuring the implied fair value of goodwill is currently referred to as step 2 of the goodwill impairment test. Step 2 requires an entity to "assign the fair value of a reporting unit to all of the assets and liabilities of that unit (including any unrecognized intangible assets) as if the reporting unit had been acquired in a business combination." Consequently, the performance of step 2 of the goodwill impairment test can result in significant cost and complexity.

As part of its goodwill impairment project, the FASB issued a proposed ASU in May 2016 that would remove step 2 from the goodwill impairment test. The proposed guidance, which is intended to simplify the accounting for goodwill impairment, would require an entity to "recognize an impairment charge for the amount by which the carrying amount exceeds the reporting unit's fair value. However, that amount should not exceed the carrying amount of goodwill allocated to that reporting unit."

The qualitative assessment of goodwill would be unchanged under the proposed ASU. However, all reporting units, even those with a zero or negative carrying amount, would apply the same impairment test. As noted in the proposal's Basis for Conclusions, goodwill of reporting units with a zero or negative carrying amount would not be impaired even when conditions underlying the reporting unit indicate that it was impaired. However, entities would be required to disclose any reporting units with a zero or negative carrying amount and the respective amounts of goodwill allocated to those reporting units.

Thinking It Through

The proposed guidance would significantly change the accounting for goodwill for reporting units with zero or negative carrying amounts. While current guidance addresses the assignment of liabilities to a reporting unit, practitioners have had questions about the assignment of debt.

[2] For more information, see Deloitte's January 27, 2014, *Heads Up*.

A reporting unit may have a negative carrying amount because of an entity's decision to assign debt to it, resulting in diversity in practice and different goodwill impairment outcomes.

The Board continued its redeliberations at its November 30, 2016, meeting, and reached the following decisions:

- *Transition* — The Board reaffirmed its decision to require the transition disclosures described in ASC 250-10-50-1(a) and ASC 250-10-50-2. The Board clarified that an entity will be able to adopt the guidance regardless of whether it evaluates goodwill for impairment by using the quantitative assessment in the period of adoption.
- *Private-company issues* — The Board decided to incorporate the guidance on impairment charges when goodwill is tax-deductible into the private-company accounting alternative. Private companies that switch from the private-company accounting alternative should apply the forthcoming guidance prospectively on or before its effective date. Further, private companies that switch from the private-company accounting alternative to the forthcoming guidance on or before the effective date would not need to justify preferability for the accounting change.

Effective Date and Transition

The Board decided that entities other than public business entities should apply the new guidance to annual and any interim impairment tests for periods beginning after December 15, 2021, with early adoption allowed.

The Board tentatively decided that public business entities that are SEC filers should apply the new guidance to annual and any interim impairment tests for periods beginning after December 15, 2019. Public business entities that are not SEC filers should apply the new guidance to annual and any interim impairment tests for periods beginning after December 15, 2020. Early adoption is allowed for all entities as of January 1, 2017. This will align the effective date for decisions reached in this project with the requirements in ASU 2016-13. The Board also affirmed prospective application as proposed.

Next Steps

The Board directed the staff to draft an ASU for vote by written ballot, with the final ASU expected to be issued in the first quarter of 2017.

Accounting for Identifiable Intangible Assets in a Business Combination

Background

In November 2014, the FASB agreed to add to its agenda a project to explore potential changes to the guidance on accounting for identifiable intangible assets in a business combination for public business entities and not-for-profit entities. The Board will evaluate whether certain intangible assets should be subsumed into goodwill.

Current Status and Next Steps

The project is in the initial deliberations phase. At the FASB's October 28, 2015, meeting, the Board decided to conduct further research in conjunction with the IASB. The boards discussed the status of their respective projects on this topic at their June 20, 2016, meeting; however, no decisions were made.

Accounting for Derecognition and Partial Sales of Nonfinancial Assets

Background

In June 2016, the FASB issued a proposed ASU that would clarify the scope of the Board's recently established guidance on nonfinancial asset derecognition (ASC 610-20) as well as the accounting for partial sales of nonfinancial assets. The proposed guidance is in response to stakeholder feedback indicating that (1) the meaning of the term "in-substance nonfinancial asset" is unclear because the Board's new revenue standard does not define it and (2) the scope of the guidance on nonfinancial assets is complex and does not specify how a partial sales transaction should be accounted for or which model entities should apply. The proposed ASU would conform the derecognition guidance on nonfinancial assets with the model for revenue transactions in ASC 606 (ASU 2014-09). Comments on the proposed guidance were due on August 5, 2016, and the FASB is analyzing the comment letters received.

Key provisions of the proposed ASU are discussed below. For more information, see Deloitte's June 14, 2016, *Heads Up*.

Scope of the Guidance on Nonfinancial Asset Derecognition and Unit of Account

The proposed ASU would require entities to apply the guidance in ASC 610-20 to the derecognition of all nonfinancial assets and in-substance nonfinancial assets. While the concept of in-substance assets resided in ASC 360-20, this guidance would not have applied to transactions outside of real estate. The FASB is therefore proposing to add to the ASC master glossary the following definition of an in-substance nonfinancial asset:

> An asset of a reporting entity that is included in either of the following:
>
> a. A contract in which substantially all the fair value of the assets (recognized and unrecognized) promised to a counterparty is concentrated in nonfinancial assets
>
> b. A consolidated subsidiary in which substantially all the fair value of the assets (recognized and unrecognized) in the subsidiary is concentrated in nonfinancial assets.
>
> An in substance nonfinancial asset does not include:
>
> a. A group of assets or a subsidiary that is a business or nonprofit activity
>
> b. An investment of a reporting entity that is being accounted for within the scope of Topic 320 on investments — debt securities, Topic 321 on investments — equity securities, Topic 323 on investments — equity method and joint ventures, or Topic 325 on other investments regardless of whether the assets underlying the investment would be considered in substance nonfinancial assets.

Thinking It Through

ASU 2014-09'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 and ASC 610-20 on sales or transfers of nonfinancial assets (including real estate).

Partial Sales

"Partial sales" are sales or transfers of a nonfinancial asset to another entity in exchange for a noncontrolling ownership interest in that entity. Entities account for partial sales before adoption of the new revenue standard principally under the transaction-specific guidance in ASC 360-20 on real estate sales and partly under ASC 845-10-30. Since ASC 606 and ASC 610-20 supersede that guidance, the proposed ASU would clarify that any transfer of a nonfinancial asset in exchange for the noncontrolling ownership interest in another entity (including a noncontrolling ownership interest in a joint venture or other equity method investment) would be accounted for in accordance with ASC 610-20.

In addition, if the reporting entity no longer retained a controlling financial interest in the nonfinancial asset, it would derecognize the asset when it transferred control of that asset in a manner consistent with the principles in ASC 606. Further, any retained noncontrolling ownership interest (and resulting gain or loss to be recognized) would be measured at fair value in a manner consistent with the guidance on noncash consideration in ASC 606-20-32-21 through 32-24.

Thinking It Through

Partial sales are common in the real estate industry (e.g., a seller transfers an asset to a buyer but retains either an interest in the asset or has an interest in the buyer). Under the current real estate guidance in ASC 360-20, entities are required to recognize a partial gain and measure the retained ownership interest in a partial sale of real estate at carryover basis. The proposed ASU would eliminate the differences in the accounting between transactions with assets and businesses and would require an entity that sells real estate assets to recognize full gain when it loses its controlling financial interest and any retained interest in such real estate would be measured at fair value.

Effective Date and Transition

The effective date of the guidance in the proposed ASU and the transition methods would be aligned with the requirements in the new revenue standard as amended by ASU 2015-14,[3] which delays the effective date of the new revenue standard by one year and permits early adoption on a limited basis. However, an entity would be permitted to use a transition approach to adopt ASC 610-20 that is different from the one it uses to adopt ASC 606 (e.g., the entity may use the modified retrospective approach to adopt ASC 610-20 and the full retrospective approach to adopt ASC 606). If different methods are used, an entity would need to provide the transition-method disclosures required by ASC 606 and indicate the method it used to adopt ASC 610-20.

Stock-Based Compensation and Employee Benefits

Modification Accounting for Share-Based Payment Arrangements

Background

In November 2016, the FASB issued a proposed ASU that would amend the scope of modification accounting for share-based payment arrangements. The proposed ASU provides guidance on the types of changes to the terms or conditions of share-based payment awards to which an entity would be required to apply modification accounting under ASC 718. Specifically, an entity would not apply

[3] For public business entities, the standard is effective for annual reporting periods (including interim reporting periods therein) beginning after December 15, 2017. For nonpublic entities, the standard is effective for annual reporting periods beginning after December 15, 2018, and interim reporting periods within annual reporting periods beginning after December 15, 2019.

modification accounting if the fair value,[4] vesting conditions, and classification of the awards are the same immediately before and after the modification.

When ASU 2016-09 was issued in March 2016 under the Board's simplification initiative, it made a change to ASC 718 regarding the exception to liability classification of an award related to an employer's use of a net-settlement feature to withhold shares to meet the employer's statutory tax withholding requirement. Under ASU 2016-09, the net settlement of an award for statutory tax withholding purposes does not result, by itself, in liability classification of the award as long as the amount withheld for taxes does not exceed the *maximum* statutory tax rate in the employee's relevant tax jurisdiction(s). Before an entity adopts ASU 2016-09, the exception applies only when no more than the number of shares necessary for the *minimum* statutory tax withholding requirement to be met is repurchased or withheld.

Upon adopting ASU 2016-09, some entities may change the net-settlement terms of their share-based payment arrangements from the minimum statutory tax rate to a higher rate up to the maximum statutory tax rate. Some constituents questioned whether this change, if made to existing awards, would require the application of modification accounting under ASC 718-20-35-3. When an entity applies modification accounting to equity-classified awards and the original awards are expected to vest (because of any service or performance conditions) on the modification date, a modification may result in incremental compensation cost.

The proposed ASU's key provisions are discussed below. For more information, see Deloitte's November 18, 2016, *Heads Up*.

Key Provisions of the Proposed ASU

Scope of Modification Accounting

The proposed ASU would amend ASC 718 to limit the instances in which modification accounting is applied. Entities would account for the effects of a modification unless all the following items are the same immediately before and after the modification:

- "The fair value (or calculated value or intrinsic value, if such an alternative measurement method is used) of the award."
- "The vesting conditions of the award."
- "The classification of the award as an equity instrument or a liability instrument."

In addition, as a consequential amendment, the proposal would remove the phrase "any of" from the definition of "modification." Under the proposed ASU, a modification would be defined as a "change in the terms or conditions of a share-based payment award."

The proposal's Basis for Conclusions provides additional clarity on the application of proposed ASC 718-20-35-2A(a), which would require the fair value to be the same immediately before and after the modification for modification accounting not to be applied. In paragraph BC11, the Board clarifies that the evaluation should be based on whether the fair value has changed, not on whether the compensation cost recognized has changed. In addition, paragraph BC14 clarifies that a computation of the fair value before and after the modification would not be expected in all cases. Rather, if the entity determines that the modification does not affect any of the inputs used in its fair value calculation, the entity most likely could conclude that the fair value would be the same immediately before and after the modification.

[4] If the measurement of the awards in the financial statements is based on calculated value or intrinsic value, the comparison before and after the modification would be based on such an alternative measurement method instead of fair value.

The proposed ASU's Basis for Conclusions also provides examples (that "are educational in nature, are not all-inclusive, and should not be used to override the guidance in paragraph 718-20-35-2A") of changes to awards for which the Board believes that modification accounting would not be required as well as those for which the Board believes that it would be required. The following table summarizes those examples:

Examples of Changes for Which Modification Accounting Would Not Be Required	Examples of Changes for Which Modification Accounting Would Be Required
• Administrative changes, such as a change to the company name, company address, or plan name. • Changes in net-settlement provisions related to tax withholdings that do not affect the classification of the award.	• Repricing of options that results in a change in value. • Changes in a service condition. • Changes in a performance condition or a market condition. • Changes in an award that result in a reclassification of the award (equity to liability or vice versa). • The addition of a change-in-control provision under which awards are immediately vested upon occurrence of the event.

Disclosures

ASC 718 currently requires entities to disclose a description of significant modifications, including the terms of the modifications, the number of employees affected, and the total incremental compensation cost resulting from the modifications. Under the proposed ASU, additional disclosures would not be required.

Thinking It Through

Entities would still be required to disclose any significant changes to the terms or conditions of share-based payment awards that meet the definition of a modification under ASC 718-20-20, even if modification accounting is not applied under the proposed ASU. For example, under the proposed ASU, if an entity changes the settlement terms of its share-based payment awards but such a change does not result in a change in fair value, vesting condition, or classification, modification accounting would not be applied. However, the entity may still be required to disclose the change in settlement terms if the modification is significant.

Effective Date and Transition

The FASB plans to determine an effective date for the final guidance after considering stakeholder feedback on the proposed ASU. Entities would apply the proposed amendments prospectively to modifications on or after the effective date, and transition disclosures would not be required.

Nonemployee Share-Based Payment Accounting Improvements

Background

In December 2015, the FASB decided to add to its agenda a project on improving the accounting for nonemployee share-based payment arrangements. When the Board previously deliberated its initial share-based payment simplification project, it decided that potential improvements to the nonemployee model could involve broader changes and take longer to complete than other simplification projects. As a result, the Board concluded that reconsideration of the accounting for nonemployee share-based payments should be moved to a separate project.

Tentative Decisions

In May 2016, the FASB tentatively decided to expand the scope of ASC 718 to include all share-based payment arrangements related to acquiring both goods and services from nonemployees. The Board's tentative decision would require an entity to apply the classification and measurement guidance in ASC 718 to nonemployee share-based payments. For example, the expected term should be used to measure the fair value of stock options or similar instruments granted to nonemployees. In addition, a nonpublic entity would be permitted to use certain practical expedients, including the use of (1) calculated value to measure certain nonemployee awards and (2) intrinsic value to measure liability-classified nonemployee awards. Further, nonemployee share-based payments initially within the scope of ASC 718 would remain within the scope of that guidance for classification and measurement purposes (even after the nonemployee awards have vested) unless the awards are modified after performance is complete.

However, the FASB tentatively decided that attribution of any cost associated with nonemployee share-based payments would continue to be accounted for under other applicable accounting literature as though the issuer had paid cash for the goods or services.

Thinking It Through

Nonemployee share-based payments issued for goods and services are accounted for under ASC 505-50. The guidance in ASC 505-50 differs significantly from ASC 718, including the (1) determination of the measurement date, (2) accounting for performance conditions, (3) ability to use nonpublic entity practical expedients, and (4) classification of awards after vesting. The tentative decisions of this project would align such guidance.

Transition

The Board tentatively decided that a modified retrospective transition approach, with a cumulative-effect adjustment to retained earnings, would generally be required for outstanding nonemployee awards at the time of adoption. However, in allowing nonpublic companies to use calculated values to measure certain nonemployee awards, the Board tentatively decided that a prospective approach should be used for all nonemployee awards that are measured at fair value after the date of adoption.

Disclosures

With the exception of disclosures specifying the income statement effects of the change in principle in the year of adoption (or interim periods therein), the Board tentatively decided that an entity should apply the disclosure requirements in ASC 250 related to a change in accounting principle.

Finally, the Board tentatively decided that the disclosure requirements for nonemployee awards should be aligned with those in ASC 718 and that these requirements did not need to be modified.

Next Steps

At the FASB's November 30, 2016, meeting, the Board directed its staff to draft a proposed ASU with a 90-day comment period. The staff indicated that the Board expects to issue the proposal in the first quarter of 2017.

Employee Benefit Plan Master Trust Reporting (EITF 16-B)

Many employee benefit plans hold investments in master trusts. Master trusts hold assets for multiple plans of either a single employer or a group of employers under common control. A plan's interest in a master trust may be through an undivided interest (a proportionate interest in the net assets of the master trust) or a divided interest (a specific ownership interest in individual investments of the master trust). Because plan interests in master trusts are becoming more common, additional presentation and disclosure guidance on interests in such trusts is needed.

In July 2016, the FASB issued a proposed ASU that seeks to improve the presentation and disclosure guidance for employee benefit plans that have investments held in master trusts. The proposed ASU addresses the following subissues related to employee benefit plan master trust reporting:

- *Presentation of master trust balances and activity on the face of the plan's financial statement* — When an employee benefit plan has investments in a master trust, the plan must disclose the balances and activity of its interest in the master trust on the face of the financial statements as well as in the footnotes. However, presentation guidance is not consistently provided within U.S. GAAP and has led to some diversity in practice in presentation of the master trust balances and activity within both the statement of net assets available for benefits and the statement of changes in net assets. To eliminate this diversity, the proposed ASU includes a provision that requires that a plan present its total interest in master trust balances and related changes in such balances as one single line item in both the statement of net assets available for benefits and the statement charges in net assets.
- *Disclosure for plans with divided or undivided interests* — The proposed ASU similarly includes a provision that requires that plans that hold either divided or undivided interests in master trusts disclose both the total master trust investment balances by general type of investments and the dollar amount of the individual plan's interest in each of those types of investments.
- *Disclosure of the master trust's other assets and liabilities* — The proposed ASU includes a provision that requires a plan to disclose both the investment-related to other asset and liability balances for the master trust and the dollar amount of the individual plan's interest in such balances.
- *Section 401(h) account investment disclosures* — A 401(h) plan is a postretirement benefit plan that may have assets funded through the entity's defined benefit pension plan assets. The proposed ASU removes the required disclosures for Section 401(h) account assets in a health and welfare plan and instead requires the health and welfare plan to provide the name of the defined benefit pension plan with which the account asset disclosures are associated.
- *Consistency between ASC topics* — Under current U.S. GAAP, benefit plan guidance is located in ASC 960, ASC 962, and ASC 965, which contain (with the exception of ASC 965) certain guidance on master trusts. The proposed ASU aligns the guidance in these ASC topics when applicable.

Effective Date and Transition

The amendments in the proposed ASU would be effective for fiscal years beginning after December 15, 2018. Early adoption would be permitted. A reporting entity would apply the guidance retrospectively to all periods presented. The final ASU is expected to be issued in January 2017.

Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost

In January 2016, the FASB issued a proposed ASU on the presentation of net periodic benefit cost as part of the Board's simplification initiative. Under the proposed guidance, entities would be required to (1) disaggregate the current service cost component from the other components of net benefit cost and present it with other current compensation costs for the related employees in the income statement and (2) present the remaining components of net benefit cost elsewhere in the income statement and outside of income from operations, if such a subtotal is presented.

Further, the proposed ASU would require retrospective application for the change in the presentation of the service cost component and the other components of net benefit cost in the income statement. An entity would disclose the nature of and reason for the change in accounting principle in the first interim and annual reporting periods in which it adopts the ASU.

The FASB received more than 35 comment letters (which were due by April 25, 2016) on the proposal from various respondents, including preparers, users, professional and trade organizations, and accounting firms. At its meeting on August 24, 2016, the FASB discussed a summary of the comments received and directed its staff to perform research on particular aspects of the proposed ASU.

Ultimately, on November 2, 2016, the Board tentatively decided the following regarding the presentation of pension and postretirement benefit costs:

- Entities should separate net benefit costs into the service cost component and other components.
- Service cost would be the only component eligible for capitalization, if appropriate, as part of an asset such as inventory or PP&E.
- Entities should report in the income statement the non-service-cost components separately from the service cost component and outside a subtotal of income from operations, if one is presented.

Effective Date and Transition

The Board tentatively decided that the final ASU will be effective for public business entities for annual reporting periods beginning after December 15, 2017, including interim periods therein. For entities other than public business entities, the amended presentation will be effective for annual reporting periods beginning after December 15, 2018.

Thinking It Through

As part of the ratemaking process for determining the prices utilities are permitted to charge customers for utility service, utility regulators generally provide specific requirements on how P&U entities should account for net benefit costs for ratemaking purposes. In addition, utility regulators may, and often do, require that a P&U entity adhere to specific accounting approaches, practices, and levels of detail not required by U.S. GAAP.

In most jurisdictions, the current regulatory guidelines require P&U entities to record all of the components of net benefit costs as an operating expense and allow for the capitalization of a percentage of all of the components of net benefit costs on qualifying construction projects. Accordingly, total net benefit costs are factored into the determination of the prices the utility is allowed to charge customers.

> Many industry observers expect that the regulatory treatment of net benefit costs, including capitalization of these costs on construction projects, will not change after the new standard is in effect. Companies must assess under ASC 980 how to account for the economic effect of a rate regulator's decision to allow recovery, over the life of the related property, of an amount of capitalized benefit costs for ratemaking purposes that is different from the amount specified by the new standard. As this publication goes to press in early 2017, companies are continuing to evaluate how ASC 980 would affect the application of the new standard. There are continuing efforts within the industry to secure an extended adoption date for P&U companies.

For additional information about the proposed ASU, see Deloitte's January 28, 2016, *Heads Up*.

Disclosure Framework

Background

In July 2012, the FASB issued a discussion paper as part of its project to develop a framework to make financial statement disclosures "more effective, coordinated, and less redundant." The paper identifies aspects of the notes to the financial statements that need improvement and explores possible ways to improve them. The FASB subsequently decided to distinguish between the "FASB's decision process" and the "entity's decision process" for evaluating disclosure requirements.

FASB's Decision Process

In March 2014, the FASB released for public comment a proposed concepts statement that would add a new chapter to the Board's conceptual framework for financial reporting. The proposal outlines a decision process to be used by the Board and its staff for determining what disclosures should be required in notes to financial statements. The FASB's objective in issuing the proposal is to improve the effectiveness of such disclosures by ensuring that reporting entities clearly communicate the information that is most important to users of financial statements. See Deloitte's March 6, 2014, *Heads Up* for additional information.

In February 2015, the Board tentatively decided that the disclosure section of each Codification subtopic (1) would state that an entity should apply materiality as described in the proposed amendments to ASC 235 in complying with the disclosure requirements and (2) would not contain language that precludes an entity from exercising discretion in determining what disclosures are necessary (e.g., "shall at a minimum provide").

In September 2015, in response to feedback from outreach activities and to maintain consistency with both current practice and the FASB's proposed ASU on the omission of immaterial disclosures (see Entity's Decision Process below for discussion of the proposed ASU), the Board issued a proposal to modify the definition of materiality in Concepts Statement 8. The proposal would replace the original discussion of materiality in Concepts Statement 8 with the U.S. Supreme Court's definition. See Deloitte's September 28, 2015, *Heads Up* for additional information.

Comments on the proposed changes to Concepts Statement 8 have been provided to the FASB.

Entity's Decision Process

In September 2015, to reduce entities' reluctance to omit immaterial disclosures, the FASB issued a proposed ASU that would amend the Codification to indicate that the omission of disclosures about immaterial information is not an accounting error. The proposal, which is part of the FASB's disclosure effectiveness initiative, notes that materiality is a legal concept applied to assess quantitative and qualitative disclosures individually and in the aggregate in the context of the financial statements taken as a whole. See Deloitte's September 28, 2015, *Heads Up* for additional information.

Comments on the proposed ASU have been provided to the FASB.

Next Steps

The FASB will continue deliberating concerns raised in comment letters and will review feedback received as a result of its outreach activities, which include testing the Board's and entity's decision processes against various Codification topics. A final concepts statement is expected to be issued after the outreach process is complete.

Topic-Specific Disclosure Reviews

In addition to proposing amendments to guidance, the FASB is analyzing ways to "further promote [entities'] appropriate use of discretion"[5] in determining proper financial statement disclosures. The Board is applying the concepts in both the entity's and the Board's decision process in considering topic-specific modifications. The FASB reached tentative decisions about disclosure requirements in the following Codification topics:

- ASC 820 (fair value measurement).
- ASC 740 (income taxes).
- ASC 715-20 (defined benefit plans).
- ASC 330 (inventory).

Proposed changes to the disclosure requirements are discussed below.

Fair Value Measurement

Objective for Disclosures

In December 2015, the FASB issued for public comment a proposed ASU that would amend the requirements in ASC 820 for disclosing fair value measurements. The proposed ASU would add the following objective to ASC 820 to encourage preparers to use discretion in complying with the disclosure requirements:

> The objective of the disclosure requirements in this Subtopic is to provide users of financial statements with information about all of the following:
>
> a. The valuation techniques and inputs that a reporting entity uses to arrive at its measures of fair value, including judgments and assumptions that the entity makes
>
> b. The effects of changes in fair value on the amounts reported in financial statements
>
> c. The uncertainty in the fair value measurement of Level 3 assets and liabilities as of the reporting date
>
> d. How fair value measurements change from period to period.

In addition, the proposed ASU would make changes (eliminations, modifications, and additions) to the fair value disclosure requirements in ASC 820, as discussed below.

[5] Quoted from "What You Need to Know About Disclosure Framework" on the FASB's Web site.

Eliminated and Modified Disclosure Requirements

Policy on Timing of Transfers Between Levels and Transfers Between Levels 1 and 2

The proposed ASU would remove the requirement in ASC 820-10-50-2C for an entity to disclose its policy on the timing of transfers between levels of the fair value hierarchy. An entity would still be required to have a consistent policy on timing of such transfers. The requirement to separately disclose the amounts transferred between Level 1 and Level 2 and the corresponding reason for doing so would also be removed.

Level 3 Fair Value Measurements

The disclosure requirements for Level 3 fair value measurements would be amended as follows:

- *Valuation process* — The proposed ASU would remove requirements in ASC 820-10-50-2(f) (and related implementation guidance in ASC 820-10-55-105) for an entity to disclose its valuation processes for Level 3 fair value measurements.

Thinking It Through

Removing the disclosure requirement in ASC 820-10-50-2(f) will result in divergence between U.S. GAAP and IFRSs. The requirement was added to the FASB's and IASB's jointly issued standard on the basis of a recommendation by the IASB's expert panel. The panel explained that the disclosure would help users understand the quality of the entity's fair value estimates and give investors more confidence in management's estimate. The FASB has proposed to remove the requirement because it would conflict with the Board's proposed concepts statement. The Board indicated that disclosure of internal control procedures is outside the purpose of the notes to the financial statements and is not required under other topics in U.S. GAAP.

Removing this requirement does not change management's responsibility for internal controls over the valuation process and related auditor testing. Further, it should not affect investor confidence in the quality of the fair value estimate given the regulatory environment in the United States (e.g., SEC and PCAOB) as well as the intense scrutiny in this area. The Board also noted that investors are typically familiar with the overall valuation process.

- *Measurement uncertainty* — The proposed ASU would retain the requirement in ASC 820-10-50-2(g) to provide a narrative description of the sensitivity of the fair value measurement to changes in unobservable inputs. However, it would clarify that this disclosure is intended to communicate information about the uncertainty in measurement as of the reporting date and not to provide information about sensitivity to future changes in fair value.
- *Quantitative information about unobservable inputs* — The proposed ASU would require disclosure of the range and weighted average of the unobservable inputs to comply with the requirement in ASC 820-10-50-2(bbb) (as shown by example in the implementation guidance in ASC 820-10-55-103). Disclosing the period used to develop significant unobservable inputs based on historical data would also be required. A private company would be exempt from such a disclosure requirement.
- *Level 3 rollforward* — The proposed ASU would retain the Level 3 rollforward requirement for entities that are not private companies. For entities that are private companies, the proposed ASU would modify the Level 3 rollforward requirement and remove the requirement to disclose the change in unrealized appreciation or deprecation related to investments held as of the balance sheet date under ASC 820-10-50-2(d). Instead, disclosures would be required about

transfers into and out of Level 3 and purchases (and issues) of Level 3 investments. The Board indicated that entities are already required to disclose the ending balance in the fair value hierarchy table, and they could disclose transfers into (and out of) and purchases (or issues) of Level 3 investments in a sentence rather than in a full rollforward as required under current guidance. A defined benefit plan sponsor that is a private company would also remove the reconciliation of beginning and ending balances for plan investments categorized as Level 3 within the fair value hierarchy (i.e., the Level 3 rollforward) and would be required to disclose transfers into and out of Level 3 and purchases (or issues) of Level 3 assets only in its defined benefit plan footnote (for more information about the FASB's project on reviewing defined benefit plan disclosures, see discussion below).

Thinking It Through

In its outreach on the Level 3 rollforward, the Board noted that some financial statement users believe that the rollforward is useful because it helps them understand management's decisions, especially for different economic cycles. The full rollforward was generally deemed less useful for users of private-company financial statements. Transfers into and out of Level 3 were generally considered to be the most useful aspect of the rollforward.

New Disclosure Requirements — Unrealized Gains and Losses

Entities that are not private companies would disclose fair value changes for assets and liabilities held as of the balance sheet date disaggregated by fair value hierarchy level (i.e., Levels 1, 2, and 3) for (1) net income before taxes and (2) comprehensive income. This is currently required only for the Level 3 amounts within net income under ASC 820-10-50-2(c) and (d). This requirement would not apply to private companies in accordance with the private-company decision-making framework.

Transition and Next Steps

The proposed ASU requires that the modifications to disclosures about changes in unrealized gains and losses and the changes in the quantitative information about unobservable inputs (see discussion above) would be applied prospectively beginning in the period of adoption. Entities would apply all other changes in disclosures retrospectively to all periods presented.

The FASB did not propose an effective date. Rather, the Board indicated that it plans to determine such date after considering stakeholders' feedback on the proposed guidance.

Comments on the proposed ASU were due by February 29, 2016, and were discussed at the FASB's meeting on June 1, 2016, at which it was decided that additional outreach would be conducted with investors and other financial statement users.

Income Taxes

Background

In July 2016, the FASB issued a proposed ASU that would modify or eliminate certain disclosure requirements related to income taxes as well as establish new requirements. The proposed ASU is the result of the application of the Board's March 2014 proposed concepts statement to disclosures about income taxes. Comments on the proposed ASU were due by September 30, 2016.

Key Provisions of the Proposed ASU

Scope

Although many of the amendments would apply to all entities that are subject to income taxes, certain amendments would apply only to public business entities.

As part of the proposal, the FASB decided that it would also replace the term “public entity,” as defined in the glossary in ASC 740-10, with “public business entity,” as defined in the ASC master glossary. The definition of a public business entity includes certain types of entities that the definition of a public entity under ASC 740 does not include. Thus, the disclosure requirements in ASC 740 that currently apply only to public entities would apply to other entities as well.

Indefinitely Reinvested Foreign Earnings

The proposed ASU would require all entities to explain any change to an indefinite reinvestment assertion made during the year, including the circumstances that caused such change in assertion. All entities would also be required to disclose the amount of earnings for which there was a change in assertion made during the year. In addition, all entities would be required to disclose the aggregate of cash, cash equivalents, and marketable securities held by their foreign subsidiaries.

Such information is intended to give financial statement users information that will help them predict the likelihood of future repatriations and the associated income tax consequences related to foreign indefinitely reinvested earnings.

Unrecognized Tax Benefits

The proposed ASU would modify the disclosure requirements for a public business entity related to unrecognized tax benefits. It would also add a requirement for entities to disclose, in the tabular reconciliation of the total amount of unrecognized tax benefits required by ASC 740-10-50-15A(a), settlements disaggregated by those that have been (or will be) settled in cash and those that have been (or will be) settled by using existing DTAs (e.g., settlement by using existing net operating loss or tax credit carryforwards).

A public business entity would also be required to provide a breakdown (i.e., a mapping) of the amount of total unrecognized tax benefits shown in the tabular reconciliation by the respective balance-sheet lines on which such unrecognized tax benefits are recorded. If an unrecognized tax benefit is not included in a balance-sheet line, such amount would be disclosed separately. In addition, a public business entity would be required to disclose the total amount of unrecognized tax benefits that are offset against existing DTAs for net operating loss and tax credit carryforwards.

Under the guidance currently in ASC 740-10-50-15(d), all entities must disclose details of tax positions for which it is reasonably possible that the total amount of unrecognized tax benefits will significantly increase or decrease in the next 12 months. The proposed ASU would eliminate this disclosure requirement.

Further, the proposed ASU would amend the example in ASC 740-10-55-217 to illustrate the applicability of the proposed disclosure requirements related to unrecognized tax benefits.

Operating Loss and Tax Credit Carryforwards

Currently, entities are required to disclose the amount and expiration dates of operating losses and tax credit carryforwards for tax purposes. Historically, there has been diversity in practice related to this disclosure requirement. The proposed ASU would reduce this diversity by requiring a public business entity to disclose the total amount of:

- Federal, state, and foreign gross net operating loss and tax credit carryforwards (i.e., not tax effected) by period of expiration for each of the first five years after the reporting date and a total for any remaining years.
- Federal, state, and foreign DTAs related to net operating loss and tax credit carryforwards (i.e., tax effected) before any valuation allowance.

Thinking It Through

Generally, an entity should measure a DTA in accordance with the recognition and measurement criteria in ASC 740. While the proposed ASU uses the term "deferred tax asset," it is unclear whether that term as used in the proposal refers to a DTA measured under the ASC 740 criteria or simply the tax-effected amount of the net operating loss and tax credit carryforwards as reflected on the income tax returns as filed.

As discussed previously, a public business entity would also be required to disclose the total amount of unrecognized tax benefits that are offset against existing DTAs for net operating loss and tax credit carryforwards.

In addition, the proposed ASU would modify the disclosure requirement related to net operating loss and tax credit carryforwards for entities other than public business entities. An entity other than a public business entity would be required to disclose the total gross amounts of federal, state, and foreign net operating loss and tax credit carryforwards (i.e., not tax effected) along with their expiration dates. The example in ASC 740-10-55-218 through 55-222 (as amended) would illustrate the applicability of these disclosure requirements.

Rate Reconciliation

ASC 740-10-50-12 currently requires a public business entity to disclose a reconciliation of the reported amount of income tax expense (or benefit) from continuing operations to the amount of income tax expense (or benefit) that would result from multiplying the pretax income (or loss) from continuing operations by the domestic federal statutory tax rate. The proposed ASU would amend the requirement for a public business entity to disclose the income tax rate reconciliation in a manner consistent with SEC Regulation S-X, Rule 4-08(h).

As amended, ASC 740-10-50-12 would continue to require a public business entity to disclose a reconciliation of the reported amount of income tax expense (or benefit) from continuing operations to the amount of income tax expense (or benefit) that would result from multiplying the pretax income (or loss) from continuing operations by the domestic federal statutory tax rate. However, the amendment would modify the requirement to disaggregate and separately present components in the rate reconciliation that are greater than or equal to 5 percent of the tax at the statutory rate in a manner consistent with the requirement in Rule 4-08(h).

Government Assistance

As a result of deliberations on its November 2015 proposed ASU on government assistance, the FASB decided to require an entity to disclose certain information related to assistance received from a governmental unit that reduces the entity's income taxes. Accordingly, the proposed ASU on income tax disclosures would require an entity that receives income-tax-related government assistance to disclose a "description of a legally enforceable agreement with a government, including the duration of the agreement and the commitments made with the government under that agreement and the amount of benefit that reduces, or may reduce, its income tax burden." This disclosure requirement would apply only when the government determined whether, under such agreement, the entity would receive assistance and, if so, how much it would receive even if it met the applicable eligibility requirements. In the absence of a specific agreement between the entity and the government, the entity would not be required to disclose this information if the entity obtained the government assistance because it met eligibility requirements that apply to all taxpayers.

Other Income Tax Disclosure Requirements

The proposed ASU would require all entities to disclose the following:

- The amount of pretax income (or loss) from continuing operations disaggregated by foreign and domestic amounts.
- The amount of income tax expense (or benefit) from continuing operations disaggregated by foreign and domestic amounts.
- The amount of income taxes paid disaggregated by foreign and domestic amounts. A further disaggregation would be required for any country that is significant to the total amount of income taxes paid.
- An enacted tax law change if it is probable that such change would have an effect on the entity in the future.

In the determination of pretax income (or loss), foreign income tax expense (or benefit), or foreign income taxes paid, "foreign" refers to any country outside the reporting entity's home country.

In addition, the proposal would require public business entities to explain any valuation allowance recognized or released during the year along with the corresponding amount.

The proposed ASU is also aligned with the guidance in the proposed ASU on assessing the materiality of disclosures, which allows an entity to consider materiality when assessing income tax disclosure requirements.

Transition Guidance and Effective Date

The proposed ASU's amendments would be applied prospectively. The FASB will determine an effective date for the final guidance after it has considered feedback from stakeholders.

Defined Benefit Plans

In January 2016, the FASB issued a proposed ASU that would modify the disclosure requirements for employers that sponsor defined benefit pension or other postretirement plans. The proposed ASU contains an overall objective for the disclosures and guidance on how an entity would consider materiality in determining the extent of its defined benefit plan disclosures. The proposed ASU would add to or remove from ASC 715 a number of disclosure requirements related to an entity's defined benefit pension and other postretirement plans. The Board believes that additional costs incurred by entities as a result of implementing the proposed new disclosure requirements would be offset by cost reductions associated with the elimination of other disclosure requirements as well as the omission of immaterial disclosures.

The amendments in the proposed ASU would be applied retrospectively to all periods presented, except for those related to disclosures about plan assets that entities measure by using the net asset value practical expedient. Such changes would be applied beginning with the initial period of adoption.

The FASB received more than 30 comment letters (which were due by April 25, 2016) on the proposal from various respondents, including preparers, professional and trade organizations, and accounting firms. At its meeting on July 13, 2016, the FASB discussed a summary of the comments received and directed its staff to perform research on particular aspects of the proposed ASU. For additional information about the proposed ASU, see Deloitte's January 28, 2016, *Heads Up*.

Thinking It Through

While some of the FASB's proposed amendments to the current disclosure requirements for fair value measurement, income taxes, and defined benefit plans would eliminate existing requirements, the proposals would also add new disclosures for both public and nonpublic entities. All P&U entities should consider what, if any, revisions to existing processes or internal controls they would have to make to obtain and prepare the information needed to comply with the proposed new disclosure requirements.

Inventory

As stated on the Project Update page of the FASB's Web site, the "objective and primary focus of the [Board's inventory disclosure framework] project is to improve the effectiveness of disclosures in notes to financial statements by clearly communicating the information that is most important to users of each entity's financial statements."

At the FASB's September 19, 2016, meeting, the Board tentatively decided that all entities would be required to disclose the following in their annual financial statements:

- Inventory disaggregated by component.
- Inventory disaggregated by measurement basis.
- Changes to the inventory balance that are not specifically related to the purchase, manufacture, or sale of inventory in the ordinary course of business.
- A qualitative description of the costs capitalized into inventory.
- The effect of LIFO liquidations on income.
- The replacement cost for LIFO inventory.

In addition, public business entities would be required to disclose, in annual and interim periods, inventory by reportable segment or by component for each reportable segment if that information is regularly provided to the chief operating decision maker.

The Board also tentatively decided to amend ASC 330 by:

- Adding a requirement to disclose the facts and circumstances leading to impairment losses.
- Removing the "substantial and unusual" threshold associated with losses from the subsequent measurement of inventory.
- Removing the existing requirements to disclose the measurement basis of inventories and situations in which inventories are stated above cost or at sales prices because those requirements would be redundant with the Board's tentative decision to require disclosure of inventory disaggregated by measurement basis.
- Removing the language in ASC 330-10-50-1 on consistent application of the measurement basis because it is duplicative of the requirements in ASC 330-10-30-15.

- Removing the language related to changes in the measurement basis of stating inventories in ASC 330-10-50-1 because it is redundant with the concepts in ASC 250.
- Removing the requirement to disclose the relationship between costs under a recognized measurement method and standard costs.

While the Board decided to retain certain disclosure requirements, including those related to separate income statement presentation of losses on firm purchase commitments and the disclosure of significant estimates, it decided that it would not require certain existing ASC 330 disclosures, including those related to the following:

- Inventory measured at fair value, net realizable value, or market value.
- An entity's LIFO method and computation techniques.
- Changes in market factors or sales prices.
- Internal and external factors affecting inventory.
- Inventory pledged as collateral.
- Terms of firm purchase commitments.
- Qualitative details about the inventory accounting policies of entities that use the retail inventory method.
- Inventory under the care, custody, or charge of an unconsolidated party.
- Royalties and other arrangements.

The Board continued its redeliberations at its November 16, 2016, meeting. At that meeting, as stated on the Project Update page of the FASB's Web site, the "Board decided to require an entity that applies the retail inventory method to qualitatively and quantitatively disclose the critical assumptions used in [its] calculation of the cost of inventory under the retail inventory method."

Transition Method and Next Steps

The Board decided that the proposed changes to disclosure requirements would be applied prospectively beginning in the period of adoption for all entities. In addition, the Board directed its staff to draft a proposed ASU for vote by written ballot. The proposed ASU is expected to be issued in the first quarter of 2017.

Section 6 — Implications of the New Revenue Model

Background

In May 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. The main provisions of the ASU are codified in ASC 606.

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."

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.

In response to feedback received by the FASB-IASB joint revenue recognition TRG, the FASB has issued the following ASUs to make certain revisions to the guidance in the new revenue standard:

- *ASU 2016-08 on principal-versus-agent considerations* — Issued in March 2016, ASU 2016-08 addresses issues regarding how an entity should assess whether it is the principal or the agent in contracts that include three or more parties. Specifically, the ASU includes guidance on (1) how to determine the unit of account for the principal-versus-agent assessment, (2) how the principal-versus-agent indicators in ASC 606 would help an entity determine whether it obtains control of a good or service (or a right to a good or service) before the good or service is transferred to the customer, and (3) how certain indicators are related to the general control principle in ASC 606. In addition, the ASU clarifies that an entity (1) should evaluate whether it is the principal or the agent for each specified good or service in a contract and (2) could be the principal with respect to certain distinct performance obligations in a contract and the agent with respect to others. See Deloitte's March 22, 2016, *Heads Up* for more information.

- *ASU 2016-10 on identifying performance obligations and licensing* — Issued in April 2016, ASU 2016-10 clarifies the new revenue standard's guidance on an entity's identification of certain performance obligations. The ASU adds guidance on immaterial promised goods and services. Other amendments include (1) a policy election for shipping and handling activities performed after control of a good is transferred to a customer and (2) clarifications related to licenses. See Deloitte's April 15, 2016, *Heads Up* for more information.

- *ASU 2016-12 on narrow-scope improvements and practical expedients* — Issued in May 2016, ASU 2016-12 (1) clarifies how to assess whether collectibility of consideration to which an entity is entitled is probable under certain circumstances, (2) adds a practical expedient to allow entities to present amounts collected and remitted for sales taxes on a net basis in revenue, (3) clarifies how to account for noncash consideration at contract inception and throughout the contract period, and (4) adds a practical expedient for assessing the impact of historical contract modifications upon transition. See Deloitte's May 11, 2016, *Heads Up* for more information.

- *ASU 2016-20 on technical corrections and improvements* — Issued in December 2016, ASU 2016-20 amends certain aspects of the new revenue standard. Included in the amendments are new optional exemptions from the disclosure requirements related to the performance obligations in specific situations in which it is unnecessary for an entity to estimate variable consideration to recognize revenue. The amendments also require expanded disclosures when an entity applies one of the optional exemptions.

Consistency in application of the new revenue standard to similar circumstances both within and across industries has been stressed by the SEC and discussed publicly to emphasize its importance. To help achieve this objective, the AICPA has formed 16 industry-specific task forces composed of auditors and company representatives from the affected industry sectors. The task forces are charged with addressing implementation questions that have a pervasive effect across a given industry and will publish interpretive guidance that can be used as a resource to promote consistency among preparers. The P&U industry task force, which is one of the 16, is developing interpretive guidance on revenue recognition for the P&U industry. This guidance will be reviewed by the AICPA's revenue recognition working group (RRWG) and the AICPA's Financial Reporting Executive Committee (FinREC) and will be subject to public comment before it is released in an AICPA Accounting Guide.

Key Accounting Issues

Although the new revenue standard may not significantly change how P&U entities typically recognize revenue, certain requirements of the standard may require a change from current practice. Discussed below are some key provisions of the new revenue standard that may affect P&U entities as well as how the guidance might be considered in some typical transactions.

Many of the items discussed below are part of ongoing projects being addressed by the P&U industry task force. It is anticipated that the evaluation of many of these issues will be addressed in early 2017. We will continue to provide an updated discussion on topics and report on any other recent developments. Nonetheless, our number one recommendation is to continue to work on implementation. A successful implementation requires early and collective discussions among a company's departments, its auditor, and its advisers.

Thinking It Through

To help entities implement the new revenue standard, Deloitte in 2016 released *A Roadmap to Applying the New Revenue Recognition Standard*, a comprehensive resource for understanding the final guidance.

Tariff Sales of a Regulated Utility

One of the issues that the P&U industry task force has reviewed is whether sales to tariff-based customers are within the scope of the new revenue standard. If such sales are deemed to be within that 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. The P&U industry task force discussed this issue with FinREC in January 2016. The RRWG and FinREC agreed with the task force consensus that sales to tariff-based customers are within the scope of the new revenue standard. The next step is public exposure.

Thinking It Through

Our view, generally, is that tariff sales would be within the scope of the new revenue standard. This is consistent with the consensus view reached by the P&U industry task force and validated through discussions with the RRWG and FinREC. With respect to the term of the contractual relationship with the customer, we believe that in the absence of an explicit or implied term, one would look to performance completed to date to determine the legal rights and obligations each party has under the contract.

Contract Modifications

P&U entities should consider how they are affected by the new revenue standard's guidance on accounting for 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 were 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 new revenue standard. 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.

As previously discussed, in May 2016, the FASB issued ASU 2016-12, which adds a practical expedient to facilitate how to evaluate historical contract modifications at transition. The ASU also defines completed contracts as those for which all (or substantially all) revenue was recognized under the applicable revenue guidance before the new revenue standard was initially applied.

Blend-and-Extend Contract Modifications

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 extend the contract term and "blend" the remaining original, higher contract rate with the lower market rate of the extension period for the remainder of the combined 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 market price for the extension-period deliveries as of the date of the modification.

Potential Impact of the New Revenue Model on B&E Contract Modifications

This is best illustrated by a simple example. Assume that a supplier and a customer enter into a fixed-volume, five-year forward sale of electricity at a fixed price of $50 per unit. Further assume that years 1 through 3 have passed and both parties have met all of their performance and payment obligations during that period. At the beginning of year 4, the customer approaches the supplier and asks for a two-year contract extension, stretching the remaining term to four years. Electricity prices have gone down since the original agreement was executed; as a result, a fixed price for the two-year extension period is $40 per unit based on forward market price curves that exist at the beginning of year 4. The customer would like to negotiate a lower rate now while it is agreeing to extend the term of the original deal.

The supplier and customer agree to a B&E contract modification. Under the modification, the $50-per-unit fixed price from the original contract with two years remaining is blended with the $40-per-unit fixed price for the two-year extension period. The resulting blended rate for the remaining delivery years is $45 per unit. Entities have thus raised questions about whether the supplier should compare (1) the total increase in the aggregated contract price with the total stand-alone selling price of the remaining goods or services ("View A") or (2) the price the customer will pay for the additional goods or services (i.e., the $45-per-unit blended price paid for the goods or services delivered during the extension period) with the stand-alone selling price of those goods or services ("View B"). In addition, the total transaction price 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 current goods or services is paid later as a result of the blending of the prices for the remainder of the combined term.

The issue was discussed with the RRWG but was ultimately elevated to a discussion with the FASB staff through the staff's technical inquiry process. During that process, the FASB staff indicated that both views are acceptable but noted that View B is more consistent with the staff's interpretation of the contract modification guidance in the new revenue standard. The staff also indicated that entities will still need to assess whether B&E transactions include significant financing components; however, the staff noted that it did not think that every B&E contract modification inherently involves a financing. The feedback from the FASB staff will be discussed with the RRWG and eventually included in the AICPA's P&U industry Accounting Guide.

Partial Terminations

A P&U entity may enter into a contract with a customer for a performance obligation satisfied over time and later agree with the customer to terminate only a discrete unsatisfied portion of that contract. For example, a P&U entity may agree to cancel the fifth year of a five-year forward electricity sale in exchange for a payment from the buyer to make the seller whole for any forgone fair value related to year 5 of the arrangement. Alternatively, a P&U entity may agree to terminate the sale of 20 percent of the total electricity to be sold in each of the five years in exchange for a payment from the buyer to make the seller whole for any forgone fair value related to those deliveries. The P&U industry task force was asked to address the accounting considerations related to such transactions. Specifically, the task force addressed whether the consideration received to terminate a discrete performance obligation (or a discrete product or service within a single performance obligation) should be (1) recognized currently (as revenue or other income) or (2) deferred and recognized as revenue over the remaining contract term. The task force reached a consensus that an entity should account for the consideration related to partial terminations by recognizing the consideration currently. That consensus will next be discussed with the RRWG. We understand that others may have analyzed this issue differently and encourage companies affected by this issue to stay tuned for updates.

Distinct Performance Obligations

The new revenue standard provides guidance on evaluating the promised "goods or services"[1] 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 new revenue standard, 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 for which delivery of the same product is required over time and is immediately consumed by the customer would generally be treated as a single performance obligation that is satisfied over 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.

Assessing Multiperiod Commodity Contracts

An entity will need to evaluate the customer's action or intent to determine whether the customer will simultaneously receive and consume a commodity that is delivered. If so, the entity's promised commodity deliveries would meet the criteria for recognizing revenue over time as a series of distinct goods or services accounted for as a single performance obligation (i.e., by meeting the criterion that the customer simultaneously receives and consumes the benefits provided by the entity's performance as the entity performs). Customers in certain industries (e.g., oil and gas, P&U) may take different actions or have different intents for the commodity delivered by the entity.

For example, a gas utility customer of an entity that explores for and produces natural gas may store natural gas in a pool until demand from its own customers requires the natural gas to be used. Conversely, customers of the gas utility may not have infrastructure with which to store natural gas in their homes and therefore must simultaneously receive and consume any natural gas delivered by the utility (e.g., to heat a stove).

An entity will need to carefully evaluate "all relevant facts and circumstances, including the inherent characteristics of the commodity, the contract terms, and information about infrastructure or other delivery mechanisms,"[2] to determine whether the criterion in ASC 606-10-25-27(a) for recognizing revenue over time is met. For more information, see Section 8.4.1 in Deloitte's *A Roadmap to Applying the New Revenue Recognition Standard*.

Determining the Stand-Alone Selling Price for Multiperiod Commodity Contracts

For companies that do not have performance obligations that meet the criteria of ASC 606-10-25-14(b) (the "series guidance") and instead have consecutive individual point-in-time deliveries, the next step would be to allocate the selling price to all of the individual point-in-time deliveries. P&U companies often enter into multiyear contracts with their customers to provide commodities at a fixed price per unit. For certain types of commodities, there may be a forward commodity pricing curve and actively traded contracts that establish pricing for all or a portion of the contract's duration. The forward

[1] Although the new revenue standard 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.

[2] Quoted from TRG Agenda Paper 43.

commodity pricing curve may provide an indication of the price at which an entity could currently buy or sell a specified commodity for delivery in a specific month.

Sometimes, "strip" pricing may be available. In strip pricing, a single price is used to represent a single-price "average" of the expectations of the individual months in the strip period, which is typically referred to as a seasonal or annual strip. Terms of the multiperiod contracts are often derived, in part, in contemplation of the forward commodity pricing curve.

Certain arrangements for storable commodities may not meet the criteria in ASC 606-10-25-15 to be accounted for as a series of distinct goods that have the same pattern of transfer to the customer (and, therefore, as a single performance obligation). In these situations, when each commodity delivery is determined to be distinct, stakeholders have questioned whether entities are required to use the forward commodity pricing curve, the spot price, or some other value as the stand-alone selling price for allocating consideration to multiperiod commodity contracts. A technical inquiry was submitted by the P&U industry task force and was completed by the FASB staff. The staff concluded that the forward curve may not be required in many cases.

Thinking It Through

We believe that entities should consider all of the relevant facts and circumstances, including market conditions, entity-specific factors, and information about the customer, in determining the stand-alone selling price of each promised good. We do not believe that entities should default to forward-curve pricing in determining the stand-alone selling price; however, certain situations may indicate that the forward curve provides the best indicator of the stand-alone selling price. In other circumstances, the contract price may reflect the stand-alone selling price for the commodity deliveries under a particular contract. The determination of the contract price and the resulting allocation of the transaction price need to be consistent with the overall allocation objective (i.e., to allocate the transaction price to each distinct good or service in an amount that depicts the amount of consideration to which the entity expects to be entitled in exchange for transferring the goods or services to the customer). Entities will need to use significant judgment in determining the stand-alone selling price in these types of arrangements. For more information, see Section 7.2.3 in Deloitte's *A Roadmap to Applying the New Revenue Recognition Standard*.

Variable Pricing

The new revenue standard requires that variable consideration be included in the transaction price under certain circumstances. An estimate of variable consideration is included in the transaction price only to the extent that it is probable[3] 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 new revenue standard 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) may present challenges related to estimating and allocating the transaction price and applying the new revenue standard's constraint guidance. For example, a P&U entity may have a multiyear contract to sell a fixed quantity

[3] "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."

of electricity each hour at a price derived from a formula, which also includes a performance bonus tied to availability. 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.

When an arrangement includes variable consideration, P&U entities should also consider whether (1) the practical expedient for measuring progress completed for performance obligations satisfied over time can be applied or (2) changes in variable consideration can be allocated to satisfied portions of distinct services provided to the customers.

P&U entities that have arrangements that include both price and volume variability should consider whether the volume variability is actually the result of optional purchases. Options for customers to purchase additional goods or services from a P&U entity would not be considered performance obligations (and, therefore, the resulting consideration would not be included in the transaction price) unless the options give rise to a material right. If the optional purchases do not give rise to a material right, the P&U entity would account for the optional purchases only once the options are exercised. The P&U industry task force concluded that volume variability will often represent optional purchases (e.g., purchase decisions under a full requirements contract). The next step is for the task force's conclusion to be reviewed by the RRWG.

Power Purchase Agreements

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

Identifying the Contract With a Customer

Two P&U entities will often enter into collaborative arrangements to develop a new generating plant or other asset; in such contracts, one of the two parties may 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 are likely to conclude under the new revenue standard that a PPA represents a single performance obligation satisfied over time because:

- The product (electricity) 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, as is frequently the case 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. Other 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.

In the determination of 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 relative portion of consideration that is fixed (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 kWh 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).

Thinking It Through

It is generally expected, given the consensus reached by the AICPA's P&U industry task force and discussion by the TRG at its July 2015 meeting, that deliveries under strip-price contracts will be recognized at the contract price and will usually not have embedded financing elements. Further, it is expected that P&U entities will be able to use the invoicing practical expedient noted above when measuring progress toward complete satisfaction of the performance obligations in contracts with other pricing conventions (e.g., step-price arrangements). Doing so, however, would require P&U entities to ensure that the value transferred to the customer under step-price arrangements is consistent with the amount that the entities have the right to bill the customer.

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. These arrangements may have characteristics similar to those of other "stand ready" obligations in which an entity is required to pay for the availability of a resource regardless of whether the entity actually uses the resource.

Identifying the Performance Obligation(s) in the Contract

As in a PPA, in a take-or-pay arrangement for electricity, the supplier would generally conclude under the new revenue standard 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 (or period of availability) 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).

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 power 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 power whereby the customer can make up deliveries not taken later in the contract period, an output measure of progress based on units delivered may be appropriate. In this case, the supplier should recognize revenue for volumes of power 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 renewable energy certificates (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

The new revenue standard 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.

A P&U entity should carefully consider its contracts with customers for multiple products and services and assess (1) whether products or services separated in accordance with the guidance in other Codification topics should be accounted for under the new revenue standard and (2) whether it should apply the new revenue standard's guidance on distinct performance obligations when separating multiple products and services in contracts with customers.

Identifying the Performance Obligation(s) 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 new revenue standard, 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 as part of a bundled arrangement, for example, meets both criteria, that promise will be considered a distinct performance obligation. Therefore, 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 new revenue standard, 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.

Sale of Capacity

The P&U industry task force has concluded that when an entity is evaluating forward sale agreements to deliver capacity to a load-serving entity, the nature of a generator's promise in an agreement to deliver capacity is that of a stand-ready obligation. The question then becomes: Is a generator's promise in a forward sale of capacity a performance obligation satisfied over time? The task force has concluded that the generator's promise in a forward sale of capacity must meet the requirements in ASC 606-10-25-15 to be accounted for as a single performance obligation satisfied over time. If those requirements are met, the generator would (1) allocate the transaction price determined in step 3 to the single performance obligation and (2) recognize revenue by using an output method that is based on time elapsed. Given that the arrangement qualifies as a series and will use an output method to measure progress toward completion, the task force has also concluded that the arrangement may qualify for the invoice practical expedient in ASC 606-10-55-18 when the seller's right to consideration corresponds directly to the value of the capacity for the given month. Under this approach, it is likely that a shaped deal, whereby the shaped pricing reflects market rates for capacity, would result in a revenue pattern that follows the contract price. The next step is for the task force's conclusions to be reviewed by the RRWG.

Sale of RECs

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.

Under the new revenue standard, the P&U entity would need to consider whether the delivery of RECs is (1) a single performance obligation satisfied over time or (2) multiple performance obligations that are each satisfied at a point in time. The P&U industry task force has reached a consensus that the delivery of RECs reflects multiple performance obligations that are each satisfied at a point in time. Part of its consensus is the conclusion that control of the RECs is transferred to the customer at the same time as delivery of the electricity — regardless of whether there is any sort of certification lag. At the time the electricity is delivered, no further transfer of control by the seller is required. Accordingly, revenue for RECs should be recognized upon delivery of the electricity to the customer. The next step is for the RRWG to review the task force's conclusion.

Contributions in Aid of Construction

Regulated P&U entities will often require third parties to make a contribution in aid of construction (CIAC) to make an investment in property, plant, and equipment (PP&E) economical and fair to all ratepayers, including those that are not parties to the requested additional infrastructure. Typically, a utility that receives a request for service will determine a maximum allowable investment by the utility for that specific service connection by using an economic feasibility model that projects the margin to be received from the use of the new infrastructure over time. If the expected margin is not adequate to support the full cost of the infrastructure, a CIAC is typically required for the unsupported portion.

Amounts in excess of the allowable investment are required to be provided by the party making the request of the utility.

Utility companies receive CIACs under various scenarios, including (but not limited to) the following:

- A governmental entity (e.g., a township) asks the utility to move a gas line to facilitate a road expansion.
- A developer asks the utility to build infrastructure necessary to connect essential utility services to homes in a new housing development.
- A prospective customer requests utility service in a remote area of the utility's service territory, or in a neighborhood not currently equipped for the particular utility service requested.
- An active customer requests that a service connection be moved or added.

Utility companies have historically accounted for the receipt of CIAC as a reduction in the total cost basis of their PP&E (not as revenue), such that only the net cost to the utility is included in plant balances. This net amount (after contribution) is also the amount subject to ratemaking.

As noted in the examples above, CIAC may be received from customers or may be received from noncustomers. The P&U industry task force has been asked to address whether CIAC received from customers should be treated as revenue and, if so, whether the recognition of such revenue should occur upon receipt or be deferred. The task force reached a consensus that CIAC received from governmental entities is outside the scope of the new revenue standard. For CIAC received from governmental entities, the task force concluded that utility companies should continue to follow historical accounting for the receipt of CIAC. The task force is discussing with the RRWG the issue of CIAC received from nongovernmental entities.

Sales of Power-Generating PP&E

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 U.S. 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 addition, entities evaluate the disposal of equipment attached to real estate assets in accordance with ASC 360-20 if the equipment is considered integral equipment.

Thinking It Through

We expect that the P&U industry task force's consensus regarding CIAC received from nongovernmental entities will be reviewed by the RRWG in consideration of accounting conclusions reached by other industries (e.g., telecommunications, midstream oil and gas, and entities with nonrecurring engineering arrangements) that also have CIAC-like arrangements. When the RRWG reviews circumstances that are similar across industries, it generally attempts to ensure that the accounting conclusions of entities in various industries are based on consistent application of the principles in the new revenue standard. Therefore, the task force's consensus may be subject to additional scrutiny as the RRWG endeavors to maintain consistency across industries.

The new revenue standard supersedes the guidance in ASC 360-20 and provides guidance on the recognition and transfer of nonfinancial assets that is codified in ASC 610-20.

On June 6, 2016, the FASB issued a proposed ASU that would clarify the scope of the Board's recently established guidance on nonfinancial asset derecognition (ASC 610-20) as well as the accounting for partial sales of nonfinancial assets. The proposed ASU would conform the derecognition guidance on nonfinancial assets with the model for revenue transactions in ASC 606.

FASB Proposal to Clarify Guidance on Derecognition of Nonfinancial Assets — Scope of ASC 610-20

The proposed ASU would clarify the scope of ASC 610-20 and require entities to apply that guidance to the derecognition of all nonfinancial assets and in-substance nonfinancial assets. Before ASU 2014-09, when the concept of in-substance nonfinancial assets resided in ASC 360-20, this guidance would not have applied to transactions outside of real estate. The FASB is therefore proposing to add to the ASC master glossary the following definition of an in-substance nonfinancial asset:

> An asset of a reporting entity that is included in either of the following:
>
> a. A contract in which substantially all the fair value of the assets (recognized and unrecognized) promised to a counterparty is concentrated in nonfinancial assets
>
> b. A consolidated subsidiary in which substantially all the fair value of the assets (recognized and unrecognized) in the subsidiary is concentrated in nonfinancial assets.
>
> An in substance nonfinancial asset does not include:
>
> a. A group of assets or a subsidiary that is a business or nonprofit activity
>
> b. An investment of a reporting entity that is being accounted for within the scope of Topic 320 on investments — debt securities, Topic 321 on investments — equity securities, Topic 323 on investments — equity method and joint ventures, or Topic 325 on other investments regardless of whether the assets underlying the investment would be considered in substance nonfinancial assets.

Accounting for Partial Sales

Under the current guidance in ASC 360-20, 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.

"Partial sales" are sales or transfers of a nonfinancial asset to another entity in exchange for a noncontrolling ownership interest in that entity. Such sales are common in the real estate industry (e.g., a seller transfers an asset to a buyer but either retains an interest in the asset or has an interest in the buyer). Entities account for partial sales before adoption of the new revenue standard principally under the transaction-specific guidance in ASC 360-20 on real estate sales and partly under ASC 845-10-30. The new guidance clarifies that any transfer of a nonfinancial asset in exchange for the noncontrolling ownership interest in another entity (including a noncontrolling ownership interest in a joint venture or other equity method investment) would be accounted for in accordance with ASC 610-20.

In addition, if the reporting entity no longer retained a controlling financial interest in the nonfinancial asset, it would derecognize the asset when it transferred control of that asset in a manner consistent with the principles in ASC 606. Further, any retained noncontrolling ownership interest (and resulting gain or loss to be recognized) would be measured at fair value in a manner consistent with the guidance on noncash consideration in ASC 606-20-32-21 through 32-24.

However, if the entity retained a controlling financial interest in a subsidiary (i.e., when the entity sold a noncontrolling ownership interest in a consolidated subsidiary), the entity would account for the transaction as an equity transaction in accordance with ASC 810 and would not recognize a gain or loss on the derecognition of nonfinancial assets. Only when the entity no longer had a controlling financial interest in a former subsidiary, and transferred control of the nonfinancial asset in accordance with ASC 606, would the entity apply the derecognition guidance in ASC 610-20.

The proposed ASU would thus eliminate the initial measurement guidance on nonmonetary transactions in ASC 845-10-30 (in a manner consistent with the FASB's deletion of the guidance in ASC 360-20) to simplify the accounting treatment for partial sales (i.e., entities would use the same guidance to account for similar transactions) and to remove inconsistencies between ASC 610-20 and the noncash consideration guidance in the new revenue standard. For more information, see Section 17.3 in Deloitte's *A Roadmap to Applying the New Revenue Recognition Standard*.

Collectibility of Consideration in Sales to Customers With Low Credit Quality

Public utilities are required by statute to serve all customers within their service territory, including those with poor creditworthiness. As a result, a utility would need to determine whether sales made to customers with low credit quality met the collectibility criterion of ASC 606-10-25-1(e) when service was provided.

There are two views on how a public utility should make a collectibility determination under the new revenue standard:

- Under one view, the utility would consider the effects of any regulatory mechanisms that are designed to reimburse it for uncollectible accounts. If the utility is able to determine that it will collect substantially all of the arrangement consideration in light of its credit risk mitigation strategies, collection efforts, and regulatory mechanisms (including rate trackers designed to allow dollar-for-dollar recovery of bad debts), revenue recognition under ASC 606 would be appropriate.
- By contrast, the other view holds that in making the collectibility assessment, the utility should not contemplate the impact of regulatory mechanisms that are designed to reimburse it for uncollectible accounts.

The P&U industry task force will be addressing this issue in the near future and will need to review any conclusions reached with the RRWG.

Presentation of Alternative Revenue Programs

While the new revenue standard 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, as defined in ASC 980-605-25-2, if those programs meet the criteria in ASC 980-605-25-4. However, in the statement of comprehensive income, revenues arising from such programs will be presented separately from revenues arising from contracts with customers that are within the scope of the new revenue standard.

Alternative revenue program revenues are realized through regulator-ordered adjustments to utility rates and are recovered or refunded in subsequent periods as electricity is sold to end-user customers. The P&U industry task force is evaluating two views on the treatment of such revenues. Under one view, the revenue amount would reflect all changes in the alternative revenue program's regulatory assets and liabilities within a period, and the adjustment of subsequent tariff rates to recover amounts originally recorded as alternative revenue program revenue would be recorded as revenue from contracts with customers (with an equal and offsetting amount recorded to alternative revenue program revenue). Under the other view, the revenue amount would reflect only the initial accrual of alternative revenue program revenues when regulator-specified criteria are met, and the subsequent billing of those amounts would be recorded as a reduction of the regulatory asset or liability when those amounts are included in subsequent tariff rates. The P&U industry task force will be addressing this issue in the near future and will need to review any conclusions reached with the RRWG.

Disclosures

The new revenue standard 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 new revenue standard'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 new revenue standard 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 new revenue standard).

The new revenue standard 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 FASB issued ASU 2015-14, which defers the effective date of the new revenue standard, ASU 2014-09, by one year for all entities and permits early adoption as of the original effective dates.

For public business entities, the standard is effective for annual reporting periods (including interim reporting periods within those periods) beginning after December 15, 2017.

The effective date for nonpublic entities is annual reporting periods beginning after December 15, 2018, and interim reporting periods within annual reporting periods beginning after December 15, 2019. Nonpublic entities may also elect to apply the new revenue standard as of any of the following:

- Annual periods beginning after December 15, 2016, including interim reporting periods.
- Annual periods beginning after December 15, 2016, and interim reporting periods within annual reporting periods beginning one year after the annual reporting period in which the new standard is initially applied.

Entities have the option of using either a full retrospective or a modified approach to adopt the guidance in the new revenue standard:

- *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, 2016.

Thinking It Through

At the December 2016 AICPA Conference on Current SEC and PCAOB Developments, during a discussion regarding transition-period activities when an entity is adopting the new revenue standard using the full retrospective method, the SEC staff highlighted the requirements for revised financial statements in new or amended registration statements.

In particular, the SEC staff discussed the requirement in Form S-3, Item 11(b), for registrants to provide revised financial statements in a new registration statement. If a registrant elects to adopt the new revenue standard by using the full retrospective method and subsequently files a registration statement on Form S-3 that incorporates by reference interim financial statements reflecting the impact of the adoption of the new revenue standard, it would be required to retrospectively revise its annual financial statements that are incorporated by reference in that Form S-3 (i.e., the annual financial statements in its Form 10-K). Those annual financial statements would include one more year of retrospectively revised financial statements (the "fourth year") than what would otherwise be required if the registrant did not file a registration statement. Filing the registration statement would also accelerate the timing related to when a registrant would be required to provide revised information for previously completed years.

Although the SEC staff recognized preparers' concerns, the staff reiterated that there are no plans to modify the requirements of Form S-3. Therefore, when adopting the new revenue standard, an entity may look to the guidance in current U.S. GAAP or IFRSs on the adoption of new accounting standards and contemplate the impracticability exception to retrospective application. The staff observed that the impracticability exception is a high hurdle and that companies may opt to consult the OCA regarding this topic.

It is important to note that the above guidance also applies to any new or amended registration statement (other than Form S-8) that is filed after a registrant files a Form 10-Q that reports the material retrospective change.

For more information, see Deloitte's December 12, 2016, *Heads Up*.

- *Modified retrospective application* — Under the modified approach, an entity recognizes "the cumulative effect of initially applying [the new revenue standard] 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 new revenue standard is applied only to existing contracts (those for which the entity has remaining performance obligations) as of, and new contracts after, the date of initial application. The new revenue standard 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 new revenue standard, including the financial statement line items and respective amounts directly affected by the standard's application. The following chart illustrates the application of the new revenue standard and legacy GAAP under the modified approach for a public company with a calendar year-end:

	2018	**2017**	**2016**
Initial Application Year	**Current Year**	**Prior Year**	**Prior Year 2**
New contracts	New revenue standard		
Existing contracts	New revenue standard + cumulative catch-up	Legacy GAAP	Legacy GAAP
Completed contracts		Legacy GAAP	Legacy GAAP

Thinking It Through

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 new revenue standard to determine whether a cumulative-effect 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 new revenue standard and determine the transition approach that is practical to apply and most beneficial to financial statement users.

For additional information about effective date and transition, see Chapter 15 in Deloitte's *A Roadmap to Applying the New Revenue Recognition Standard*.

SAB Topic 11.M Considerations

SAB Topic 11.M provides disclosure requirements for those accounting standards not yet adopted. Specifically, when an accounting standard has been issued but need not be adopted until some future date, a registrant should include disclosure of the impact that the recently issued accounting standard will have on the financial position and results of operations of the registrant when such standard is adopted in a future period. The SEC staff believes that this disclosure guidance applies to every issued accounting standard not yet adopted by the registrant unless the standard's impact on the registrant's financial position and results of operations is not expected to be material.

At the September 22, 2016, EITF meeting, SEC Assistant Deputy Chief Accountant Jenifer Minke-Girard made an announcement regarding SAB Topic 11.M. Ms. Minke-Girard indicated that when a registrant is unable to reasonably estimate the impact of adopting the new revenue standard, the registrant should consider providing additional qualitative disclosures about the significance of this impact on its financial statements. She further noted that the SEC staff would expect such disclosures to include a description of:

- The effect of any accounting policies that the registrant expects to select upon adoption of the new revenue standard.
- How such policies may differ from the registrant's current accounting policies.
- The status of the registrant's implementation process and the nature of any significant implementation matters that have not yet been addressed.

There will not be a one-size-fits-all model for communicating the impact of adoption, but entities could consider providing (1) a short narrative that qualitatively discusses the impact of the change or (2) tabular information (or ranges) comparing historical revenue patterns with the expected accounting under ASC 606, to the extent that such information is available. See Section 20.6.1 in Deloitte's *A Roadmap to Applying the New Revenue Recognition Standard* for illustrative SAB Topic 11.M disclosures related to the adoption of the new revenue standard.

Section 7 — Overview of the New Leases Standard

Background

In February 2016, after working with the IASB on a joint leases project for almost a decade, the FASB finally issued its new standard on accounting for leases, ASU 2016-02.[1] The leases project's primary objective was to address the off-balance-sheet financing concerns related to lessees' operating leases. However, developing an approach that requires all operating leases to be recorded on the balance sheet proved to be no small task. The FASB and IASB had to grapple with matters such as (1) whether an arrangement is a service or a lease, (2) what amounts should be initially recorded on the lessee's balance sheet for the arrangement, (3) how to reflect the effects of leases in the statement of comprehensive income of a lessee (a point on which the FASB and IASB were unable to agree), and (4) how to apply the resulting accounting in a cost-effective manner.

Accordingly, the FASB's new standard introduces a lessee model that brings most leases onto the balance sheet. In addition, the standard aligns certain underlying principles of the new lessor model with those in ASC 606, the FASB's new revenue recognition standard (e.g., those that help entities evaluate how collectibility should be considered and determine when profit can be recognized). The ASU also addresses other concerns related to the current leases model, which is almost 40 years old. For example, the new standard eliminates the requirement that entities use bright-line tests to determine lease classification. The standard also requires lessors to be more transparent about their exposure to risks regarding the changes in value of their residual assets and about how lessors manage that exposure.

The changes introduced by the new leases standard may significantly affect entities in the P&U industry because of their extensive use of fixed assets under contracts that may qualify as leases under the new guidance. P&U entities often enter into agreements that are frequently customized and include services and other components critical to completing the contracts. While under current guidance the accounting for operating leases is often similar to that for service contracts, this will no longer be the case under the new standard. P&U entities will therefore need to assess many service and lease contracts to determine whether such agreements meet, or have components that meet, the new definition of a lease.

Key Provisions

Scope

Like the scope of the current guidance on leases, the scope of the new guidance is limited to leases of property, plant, and equipment (PP&E). The scope excludes (1) leases of intangible assets; (2) leases to explore for or use minerals, oil, natural gas, and similar nonregenerative resources; (3) leases of biological assets; (4) leases of inventory; and (5) leases of assets under construction.

Thinking It Through

Under the proposal issued by the boards in May 2013, the scope of the lease accounting guidance would have included inventory (e.g., spare parts and supplies) and construction work in progress (CWIP). However, constituents expressed concerns that if the proposed

[1] The ASU supersedes ASC 840 and creates ASC 842. On January 13, 2016, the IASB issued IFRS 16, its final standard on leases.

guidance had applied to CWIP, build-to-suit transactions (in which the customer is involved with the construction activity) may have been accounted for as leases. In response, the FASB revisited the scope of the guidance in late 2015 and decided to limit it to PP&E. However, the FASB also decided to include guidance on a lessee's control of an underlying asset that is being constructed before lease commencement. That is, if a P&U entity that is involved in the construction of PP&E it intends to lease is determined to control the asset during the construction period, it will be considered the owner of the CWIP for accounting purposes and will need to assess the arrangement under the new standard's sale-leaseback guidance once construction is completed.

In addition, questions have arisen about whether easements or rights-of-way would or could be within the scope of the new standard. These questions are often based on the notion that these arrangements are intangibles and would therefore be automatically excluded from the scope of the standard. We do not believe that these arrangements are automatically excluded from the scope of the standard; rather, we believe that they would require analysis to determine whether they represent leases. We expect that this analysis will often come down to the economic benefits test and an analysis of whether the easement holder has exclusive use of the property in question. For example, in an arrangement in which a company is allowed to run electric transmission assets through a farmer's fields, it will be important to understand whether the farmer can still use the acreage that lies over or under the assets. If so, we would generally expect the easement holder to conclude that he or she does not receive substantially all of the economic benefits of the land and therefore that he or she does not have a lease. Given the volume of easements and rights-of-way held by some P&U entities, we recommend segregating these arrangements on the basis of similar terms and investigating the rights retained by the landowner as a starting point to the analysis.

Finally, scoping questions have also arisen regarding pole attachment arrangements, whereby a utility allows a third party to attach equipment (e.g., telephone or cable wires) to its utility poles for a monthly fee. We understand that multiple industry groups (representing both potential lessees and potential lessors) are evaluating these arrangements to determine whether they meet the definition of a lease under ASC 842. We believe that the ability of the pole owner to relocate the equipment on the pole will be a relevant consideration. To the extent that the pole owner can change the location of the equipment on the pole, the owner may be able to conclude that he or she has a substantive substitution right, and therefore there will not be an identified asset in the arrangement. We understand that the pole owner often has the ability to relocate the attached equipment as long as service is not compromised.

Definition of a Lease

Identified Asset

The new standard defines a lease as "a contract, or part of a contract, that conveys the right to control the use of identified property, plant, or equipment (an identified asset) for a period of time in exchange for consideration." Control is considered to exist if the customer has both of the following:

- The "right to obtain substantially all of the economic benefits from the use of [an identified] asset."
- The "right to direct the use of the [identified] asset."

The notion of an identified asset is mostly consistent with that in current U.S. GAAP. Under this concept, a leased asset must be identifiable either explicitly (e.g., by a named generating asset) or implicitly (e.g., the asset is the only one available to meet the requirements of the contract). A specified asset can also be a physically distinct portion of a larger asset (e.g., one floor of a building). However, a capacity portion of a larger asset that is not physically distinct (e.g., a percentage of a natural gas pipeline's or storage facility's total capacity) will generally not be a specified asset unless that capacity portion reflects substantially all of the larger asset's overall capacity.

The evaluation of whether there is an identified asset depends on whether a supplier has a substantive substitution right throughout the period of use. Substitution rights are considered substantive if the supplier has the practical ability to substitute alternative assets throughout the period of use (i.e., the customer cannot prevent the supplier from doing so, and alternative assets are readily available to, or can be quickly sourced by, the supplier), and the supplier could benefit economically from the substitution.

An entity must use significant judgment when determining whether a substitution right is substantive. The entity should consider the facts and circumstances at the inception of the contract and exclude from its assessment circumstances that are not likely to occur over the contract term. The entity should also consider the asset's physical location. For example, it is more likely that the supplier will benefit from the substitution right if the identified asset is located at the supplier's rather than at the customer's premises (i.e., because the costs of substituting the asset may be lower). It may be difficult for a customer to determine whether the supplier's substitution right is substantive. For example, the customer may not know whether the substitution right gives the supplier an economic benefit. A customer should presume that a substitution right is not substantive if it is impractical to prove otherwise.

Thinking It Through

The requirement that a substitution would provide an economic benefit to the supplier is a higher threshold than that in current U.S. GAAP. Accordingly, we expect more arrangements to be subject to lease accounting by virtue of the new standard's changes to the evaluation of substitution rights.

Convey the Right to Control the Use

With regard to a customer's right to control the use of the identified asset, the definition of a lease under the new standard represents a significant change from previous guidance. Under current U.S. GAAP, an entity's taking substantially all of the outputs of an identified asset was considered indicative of the customer's right to control the use of that asset if the pricing per unit in the arrangement was neither fixed nor equal to the market price per unit at the time of delivery (e.g., a power purchase agreement (PPA) in which the off-taker purchases substantially all of the outputs of a generating asset).

By contrast, the new standard aligns the assessment of whether a contract gives the customer the right to control the use of the specified asset with the concept of control developed as part of the FASB's new revenue standard. Accordingly, a contract evaluated under the new standard is deemed to convey the right to control the use of an identified asset if the customer has both the right to direct, and obtain substantially all of the economic benefits from, the use of that asset. The right to direct the use of the specified asset would take into account whether the customer has the right to determine — or predetermine — how and for what purpose the asset is used. Economic benefits from the use of the specified asset would include its primary products and by-products or other economic benefits that the customer can realize in a transaction with a third party (e.g., renewable energy credits).

Thinking It Through

In determining whether a lease exists under the new standard, an entity would emphasize its ability to direct the use of the asset. This guidance is significantly different from today's model, under which a lease can exist on the basis of the level of output taken by the customer, and, therefore, we expect fewer off-take arrangements to be leases in the P&U industry. Dispatch rights held by an off-taker will generally convey control; however, off-take arrangements with predefined delivery schedules may not meet the control requirement. To help illustrate the factors for an entity to consider when evaluating whether a contract is or contains a lease, the final standard provides three examples that apply to the P&U sector (see ASC 842-10-55-108 through 55-123).

Lessee Accounting Model

Initial Measurement

The initial measurement of a lease is based on a right-of-use (ROU) asset approach. Accordingly, once the standard is effective, **all** leases (finance and operating leases) other than those that qualify for the short-term lease exception must be recognized as of the lease commencement date on the lessee's balance sheet. A lessee will recognize a liability for its lease obligation, measured at the present value of lease payments not yet paid (excluding variable payments based on usage or performance), and a corresponding asset representing its right to use the underlying asset over the lease term. The initial measurement of the ROU asset will also include (1) initial direct costs[2] (e.g., legal fees, consultant fees, commissions paid) that are incremental costs of a lease that would not have been incurred had the lease not been executed and (2) any lease payments made to the lessor before or as of the commencement of the lease. The ROU asset will be reduced for any lease incentives received by the lessee (i.e., consideration received from the lessor will reduce the ROU asset).

In addition to those payments that are directly specified in a lease agreement and fixed over the lease term, lease payments include variable lease payments that are considered in-substance fixed payments (e.g., when a variable payment includes a floor or a minimum amount). However, the fact that a variable lease payment is virtually certain (e.g., a variable payment for highly predictable output under a renewable PPA) does not make the payment in-substance fixed. Therefore, it will not be included in the determination of a lessee's lease obligation and ROU asset or a lessor's net investment in the lease.

Thinking It Through

PPAs for the output of a wind farm may include payment terms that are 100 percent contingent on production. The wind farm developer may undertake an engineering production case to support the wind farm's expected annual energy output at a particular level (e.g., 95 percent probability, or P95 production level). Although the off-taker from the wind farm may consider the expected P95 production to indicate a relatively fixed or minimum amount of annual delivered energy, that expected amount is contingent (i.e., if the wind does not blow, payment will be zero). Therefore, the expected amount in this case would not constitute an in-substance fixed lease payment. Some renewable PPAs provide for a guaranteed minimum production level to give the buyer price certainty over a minimum volume of electricity and to facilitate compliance with renewable portfolio standards. In general, we would not expect such provisions to establish a fixed lease payment obligation, since these provisions typically settle financially with a payment to the off-taker (current market price of power multiplied by volume shortfall) and therefore do not establish a minimum obligation on the part of the lessee. In other words, it is not possible to guarantee physical output from these facilities, given their dependence on weather, and these provisions are designed to protect the off-taker from the financial burden of buying replacement power, not to ensure a minimum level of revenue for the seller.

[2] The new model defines "initial direct costs" as those incremental costs "that would not have been incurred if the lease had not been obtained" (executed).

Subsequent Measurement

The FASB decided in the ASU to maintain a dual-model approach, in which a lessee classifies the lease on the basis of whether the control of the underlying asset is effectively transferred to the lessee (e.g., substantially all the risks and rewards incidental to ownership of the underlying asset are transferred to the lessee). Lessees would classify a lease as either a finance lease or an operating lease by using classification criteria similar to those in IAS 17.

Therefore, lessees will classify a lease as a finance lease if any of the criteria below are met at the commencement of the lease:[3]

- "The lease transfers ownership of the underlying asset to the lessee by the end of the lease term."
- "The lease grants the lessee an option to purchase the underlying asset that the lessee is reasonably certain to exercise."
- "The lease term is for the major part of the remaining economic life of the underlying asset."[4]
- "The present value of the sum of the lease payments and any residual value guaranteed by the lessee . . . equals or exceeds substantially all of the fair value of the underlying asset."
- "The underlying asset is of such a specialized nature that it is expected to have no alternative use to the lessor at the end of the lease term."

An entity determines the lease classification at lease commencement and is not required to reassess its classification unless (1) the lease is subsequently modified and the modification is not accounted for as a separate contract or (2) there is a change in lease term or a change in the assessment of the exercise of a purchase option.

Thinking It Through

The FASB adopted the dual-model approach on the premise that all leases are not created equal. That is, some leases are more akin to an alternate form of financing for the purchase of an asset, while others are truly the renting of the underlying property.

While the ASU's classification criteria are similar to those in IAS 17, they vary from the current requirements in U.S. GAAP (i.e., the specific quantitative thresholds have been removed, and a fifth criterion, which does not exist under ASC 840, has been added). As a result, a lease that would have been classified as an operating lease may be classified as a finance lease under the ASU. In addition, as a reasonable approach to assessing significance, an entity is permitted to use the bright-line thresholds that exist under ASC 840 when determining whether a lease would be classified as a finance lease.

An entity will also assess land and other elements in a real estate lease as separate lease components under the new standard unless the accounting result of doing so would be insignificant. This approach is also similar to current guidance under IFRSs but will reflect a change from that in U.S. GAAP, under which a lessee is required to account for land and buildings separately only when (1) the lease meets either the transfer-of-ownership or bargain-purchase-option classification criterion or (2) the fair value of the land is 25 percent or more of the total fair value of the leased property at lease inception. This change may result in more bifurcation of real estate leases into separate lease components and may affect the allocation of the lease payments to the various elements.

[3] Quoted text is from ASC 842-10-25-2.

[4] The ASU provides an exception to this lease classification criterion for leases that commence "at or near the end" of the underlying asset's economic life. The ASU indicates that a lease that commences in the final 25 percent of an asset's economic life is "at or near the end" of the underlying asset's economic life.

Finance Leases

For finance leases, the lessee will use the effective interest rate method to subsequently account for the lease liability. The lessee will amortize the ROU asset in a manner similar to that used for other nonfinancial assets; that is, the lessee will generally amortize the ROU asset on a straight-line basis unless another systematic method is appropriate. Together, the amortization and resulting interest expense will result in a front-loaded expense profile similar to that of a capital lease arrangement under current U.S. GAAP. Entities will separately present the interest and amortization expenses in the income statement.

Operating Leases

For operating leases, the lessee will also use the effective interest rate method to subsequently account for the lease liability. However, the subsequent measurement of the ROU asset will be linked to the amount recognized as the lease liability (unless the ROU asset is impaired). Accordingly, the ROU asset will be measured as the lease liability adjusted by (1) any accrued or prepaid rents, (2) unamortized initial direct costs and lease incentives, and (3) impairments of the ROU asset. As a result, the total lease payments made over the lease term will be recognized as lease expense (presented as a single line item) on a straight-line basis unless another systematic method is more appropriate.

Thinking It Through

While the ASU discusses subsequent measurement of the ROU asset arising from an operating lease primarily from a balance sheet perspective, a simpler way to describe it would be from the viewpoint of the income statement. Essentially, the goal of operating lease accounting is to achieve a straight-line expense pattern over the term of the lease. Accordingly, an entity effectively takes into account the interest on the liability (i.e., the lease obligation consistently reflects the lessee's obligation on a discounted basis) and adjusts the amortization of the ROU asset to arrive at a constant expense amount. To achieve this, the entity first calculates the interest on the liability by using the discount rate for the lease and then deducts this amount from the required straight-line expense amount for the period (determined by taking total payments over the life of the lease, net of any lessor incentives, plus initial direct costs, divided by the lease term). This difference is simply "plugged" as amortization of the ROU asset to result in a straight-line expense for the period. By using this method, the entity recognizes a single operating lease expense rather than separate interest and amortization charges, although the effect on the lease liability and the ROU asset in the balance sheet reflects a bifurcated view of the expense. Note, however, that the periodic lease cost cannot be less than the calculated interest on the lease liability (i.e., the amortization of the ROU asset, or plug amount, cannot be negative).

Regulated utilities will be pleased that the FASB carried forward the guidance that allows lease expense treatment to be consistent with the effects of rate-making. Specifically, ASC 980-842-45-1 states, "Topic 842 specifies criteria for classification of leases and the method of accounting for each type of lease. For rate-making purposes, a lease may be treated as an operating lease even though the lease would be classified as a finance lease under those criteria. In effect, the amount of the lease payment is included in allowable costs as rental expense in the period it covers." This language is virtually identical to the guidance currently in ASC 980-840-45 and, accordingly, we do not expect a change in practice in this area as a result of ASC 842.

Impairment

Regardless of the lease classification, a lessee will subject the ROU asset to impairment testing in a manner consistent with that for other long-lived assets (i.e., in accordance with ASC 360). If the ROU asset for a lease classified as an operating lease is impaired, the lessee will amortize the remaining ROU asset under the subsequent measurement requirements for a finance lease — evenly over the remaining lease term unless another systematic method is appropriate. In addition, in periods after the impairment, a lessee will continue to present the ROU asset amortization and interest expense as a single line item.

Lessor Accounting

After proposing various amendments to lessor accounting, the FASB ultimately decided to make only minor modifications to the current lessor model. The most significant changes align the profit recognition requirements under the lessor model with those under the FASB's new revenue recognition requirements and amend the lease classification criteria to be consistent with those for a lessee. Accordingly, the ASU requires a lessor to use the classification criteria discussed above to classify a lease, at its commencement, as a sales-type lease, direct financing lease,[5] or operating lease:

- *Sales-type lease* — The lessee effectively gains control of the underlying asset. The lessor derecognizes the underlying asset and recognizes a net investment in the lease (which consists of the lease receivable and unguaranteed residual asset). Any resulting selling profit or loss is recognized at lease commencement. Initial direct costs are recognized as an expense at lease commencement unless there is no selling profit or loss. If there is no selling profit or loss, the initial direct costs are deferred and recognized over the lease term. In addition, the lessor recognizes interest income from the lease receivable over the lease term.

  In a manner consistent with ASC 606, if collectibility of the lease payments plus the residual value guarantee is not probable, the lessor does not record a sale. That is, the lessor will not derecognize the underlying asset and will account for lease payments received as a deposit liability until (1) collectibility of those amounts becomes probable or (2) the contract has been terminated or the lessor has repossessed the underlying asset. Once collectibility of those amounts becomes probable, the lessor derecognizes the underlying asset and recognizes a net investment in the lease. If the contract has been terminated or the lessor has repossessed the underlying asset, the lessor derecognizes the deposit liability and recognizes a corresponding amount of lease income.

- *Direct financing lease* — The lessee does not effectively obtain control of the asset, but the lessor relinquishes control. This occurs if (1) the present value of the lease payments and any residual value guarantee (which could be provided entirely by a third party or consist of a lessee guarantee coupled with a third-party guarantee)[6] represents substantially all of the fair value of the underlying asset and (2) it is probable that the lessor would collect the lease payments and any amounts related to the residual value guarantee(s). The lessor derecognizes the underlying asset and recognizes a net investment in the lease (which consists of the lease receivable and unguaranteed residual asset). The lessor's profit and initial direct costs are deferred and amortized into income over the lease term. In addition, the lessor recognizes interest income from the lease receivable over the lease term.

- *Operating lease* — All other leases are operating leases. In a manner similar to current U.S. GAAP, the underlying asset remains on the lessor's balance sheet and is depreciated consistently with other owned assets. Income from an operating lease is recognized on a straight-line basis unless another systematic basis is more appropriate. Any initial direct costs (i.e., those that are incremental to the arrangement and would not have been incurred if the lease had not been

[5] The FASB decided not to allow leveraged lease treatment for new leases after the effective date of ASC 842. Existing leverage leases are grandfathered unless modified after adoption.

[6] If the present value of lease payments plus a lessee-provided residual value guarantee represents substantially all of the fair value of the underlying asset, the lessor classifies the lease as a sales-type lease.

obtained) are deferred and expensed over the lease term in a manner consistent with the way lease income is recognized.

Thinking It Through

While the FASB's goal was to align lessor accounting with the new revenue guidance in ASC 606, an important distinction may affect P&U lessors, particularly those in the renewable energy sector. Under ASC 606, variable revenues are estimated and included in the transaction price, subject to a constraint. By contrast, under the new leases standard, variable lease payments would generally be excluded from the determination of a lessor's lease receivable. Accordingly, a direct financing lease or a sales-type lease that has a significant variable component may result in an inception loss (i.e., a day 1 loss) for the lessor if the lease receivable plus the unguaranteed residual asset is less than the net carrying value of the underlying asset being leased. This could occur if payments on a lease of, for example, a solar farm are based entirely on the production of electricity (i.e., 100 percent variable). At the FASB's November 30, 2016, meeting, the Board discussed whether a day 1 loss would be appropriate in these situations or whether other possible approaches would be acceptable, including the use of a negative discount rate to avoid the loss at commencement. The Board asserted that while stakeholders may disagree with the day 1 loss outcome, ASC 842 is clear on how the initial measurement guidance should be applied to sales-type leases. In addition, the Board stated that the use of a negative discount rate would not be appropriate and should not be applied under ASC 842.

For those leases that are classified as sales-type or direct financing leases, there are still open questions on the accounting for nonrecurring capital projects, such as major maintenance to a plant, that are typically performed and capitalized by the asset owner under a defer and amortize model. Because the lessor will derecognize the underlying asset, there is an open question about whether it would be appropriate to capitalize the major maintenance costs for an asset that is no longer recorded on the balance sheet.

Lessors affected by either of these issues should consult with their professional advisers and monitor developments during the ASU's implementation phase.

Effective Date and Transition

The new guidance is effective for public business entities for annual periods beginning after December 15, 2018 (i.e., calendar periods beginning January 1, 2019), and interim periods therein. For all other entities, the ASU is effective for annual periods beginning after December 15, 2019 (i.e., calendar periods beginning January 1, 2020), and interim periods thereafter. Early adoption is permitted for all entities. Entities are required to apply a modified retrospective method of adoption, and the FASB has proposed several forms of transition relief that should significantly ease the burden of adoption.

Thinking It Through

Under current U.S. GAAP, entities may adopt the new leases standard before they adopt the new revenue guidance (even though the new revenue standard has an earlier mandatory effective date). On the basis of our discussions with the FASB's staff, it is our understanding that such early adopters (1) will be expected to apply the relevant new revenue guidance to the extent that it affects their lease accounting and (2) must wait to apply all other aspects of the new revenue standard until they have fully adopted that standard.

Implications for P&U Entities

Power Purchase Agreements

Under current lease accounting guidance, a PPA is accounted for as a lease if the off-taker (1) agrees to buy all, or substantially all, of the output(s) of a specified generating asset and (2) pays for the output(s) at pricing terms that are neither fixed per unit nor equal to the current market price per unit at the time of delivery. However, the new definition of a lease focuses on whether the off-taker has control of the right to use the specified generating asset. That is, an arrangement is not considered a lease solely on the basis of the pricing, and the extent, of outputs purchased under the contract. Rather, P&U entities have to determine whether a PPA gives the off-taker control of an identified generating asset because the off-taker has the right to direct, and obtain substantially all of the economic benefits from, the use of the asset.

Right to Direct the Use of the Asset

An off-taker has the right to direct the use of a specified generating asset if it can determine how and for what purpose that asset is used. Further, the extent to which an off-taker determines how and for what purpose the specified generating asset is used will depend on whether the PPA grants the off-taker decision-making rights over that asset. Therefore, an off-taker should (1) identify the decision-making rights that most affect how and for what purpose the generating asset is used throughout the off-taker's period of use (i.e., which decision-making rights most affect the economic benefits to be derived from the use of the generating asset) and (2) determine who controls those rights. Dispatch rights will generally convey control to the off-taker. Curtailment rights should also be analyzed. If the decisions related to how and for what purpose the asset is used are predetermined (by contract or the nature of the asset), the assessment will focus on whether the off-taker controls operations and maintenance (O&M) or designed the asset, either of which would be deemed to convey the right to direct the use of the identified asset to the off-taker. We expect that the decisions related to how and for what purpose the asset is used will be predetermined for many arrangements involving renewable energy generation, given the limited number of strategic decisions about generating assets that are made during the commercial operations phase.

Thinking It Through

As described above, we expect that dispatch rights held by the buyer will constitute control under the new standard. In some markets, however, dispatch decisions are ultimately made by an independent system operator on the basis of a consideration of bid prices and any transmission system constraints (i.e., assuming no constraints, generating units will be dispatched economically by accepting the lowest bids first), and therefore neither the owner nor the off-taker can mandate physical production. While the bid-in process is not explicitly the same as dispatch rights held by an off-taker, companies should consider whether controlling the bidding process conveys control to the off-taker, since that is the right that an owner would normally exercise in these markets to influence whether and when the owner's plant runs.

In the renewable energy sector, off-takers typically buy under must-take arrangements and dispatch rights are not present because of the weather-dependent nature of the generating assets. However, it is common for off-takers to have curtailment rights for both operational (e.g., to protect the grid) and economic (e.g., to avoid buying at a loss when locational marginal prices are negative) reasons. While such rights should be analyzed to understand their purpose and financial consequences to the off-taker, we do not expect curtailment rights to convey control in most circumstances. We believe that the important control decisions (those about how and for what purpose) have effectively been predetermined for weather-dependent assets such as wind and solar farms. Curtailment rights protect a purchaser from unforeseen operational and market pricing anomalies but are inherently different from dispatch rights on a unit that is standing ready to produce.

It is important to note that the decision-making rights that most affect the economic benefits to be derived from a generating asset will differ depending on the nature of the asset. The table below discusses decision-making rights that an off-taker may be granted in a PPA and presents our current thinking on whether those rights determine how and for what purpose fossil fuel and alternative generating assets are used.

Nature of Generating Asset	Off-Taker's Decision-Making Rights	Do the Off-Taker's Decision-Making Rights Determine How and for What Purpose the Generating Asset Is Used?
Fossil fuel (e.g., coal, natural gas)	Dispatch rights (i.e., rights to make decisions about whether, and how much, to produce from the generating asset).	Yes. Dispatch rights provide the off-taker with the right to change whether electricity is produced from the generating asset and the quantity of the electricity that is produced, which is the decision-making right that most affects the economic benefits to be derived from the generating asset and thus represents the right to determine how and for what purpose the asset is used throughout the period of use.
	Rights to provide the fuel used by the generating asset to generate electricity and determine generation timing (i.e., a tolling arrangement).	Yes. The off-taker's right to toll fuel through the generating asset for conversion into electricity inherently provides the off-taker with the right to change when and whether the electricity is produced from the generating asset. Those decision-making rights most affect the economic benefits to be derived from the generating asset and thus determine how and for what purpose the asset is used throughout the period of use.
	Rights to make decisions about the operation and maintenance of the generating asset throughout the period of use.	No. Although operating and maintaining the generating asset is essential to its efficient use, decisions about those activities do not by themselves most affect how and for what purpose the generating asset is used; rather, they are contingent upon the decisions about how and for what purpose the generating asset is used (e.g., dispatch rights, contractually stated production schedule).
	Rights that require the supplier to follow prudent utility operating practices in running the generating asset.	No. Requirements that either party in an off-take arrangement must follow appropriate utility operating practices define the scope of the parties' rights related to the generating asset but do not affect which party has the right to direct the use of the asset.

(Table continued)

Nature of Generating Asset	Off-Taker's Decision-Making Rights	Do the Off-Taker's Decision-Making Rights Determine How and for What Purpose the Generating Asset Is Used?
Alternative (e.g., wind, solar)	Design of the generating asset before its construction.	Yes. The relevant decisions about how and for what purpose the asset is used are predetermined on the basis of the nature of the asset. However, the off-taker made the decisions about the generating asset's design before contract inception that predetermined how and for what purpose the generating asset will be used throughout the off-taker's period of use.
	Rights to make decisions about the operation and maintenance of the generating asset throughout the period of use.	Yes. The relevant decisions about how and for what purpose the asset is used are predetermined on the basis of the nature of the asset. Accordingly, decisions about operating and maintaining an alternative generating asset are often among the only decisions available to be made throughout the period of use that do affect the economic benefits to be derived. Thus, the off-taker's decision-making rights over O&M — and the lack of any rights held by the supplier to change those instructions — give the off-taker the right to direct the asset's use throughout the period of use.
	Rights that require the supplier to follow prudent utility operating practices in running the generating asset.	No. Requirements that either party in an off-take arrangement must follow appropriate utility operating practices define the scope of the parties' rights related to the generating asset but do not affect which party has the right to direct the use of the asset.

Thinking It Through

We anticipate that the assessment of an entity's involvement in design will require the use of significant judgment under the new standard and will be particularly relevant for arrangements involving renewable generating assets. Because those assets are not dispatchable, an entity is likely to conclude that how and for what purpose a generating asset is used are predetermined (on the basis of the nature of the asset). Accordingly, the analysis will focus on control over O&M or design. Control over O&M will probably be easy to determine; typically, the asset owner (the supplier) retains responsibility for O&M. However, it will often be more difficult to determine whether the off-taker had sufficient involvement in the design of the facility to effectively convey control. Important decisions regarding design are likely to include siting and determining the specific technology to be used. We understand that EEI's lease accounting group will be working on guidance in this area to assist companies in making informed judgments about design, and we plan to participate in that process.

Other important decision-making rights that affect the economic benefits to be derived from a generating asset should also be considered in the assessment of whether the off-taker's decision-making rights most affect how and for what purpose the asset is used. Such rights may include but are not limited to:

- The off-taker's right to determine the facility's operator.
- The off-taker's right to determine specific operating procedures, outside those requiring the operator to follow prudent utility operating practices.

In all scenarios, the off-taker needs to evaluate, on the basis of the specific facts and circumstances, whether it has the right to determine how and for what purpose a generating asset is used and, thus, the right to direct the use of the asset. The off-taker will need to use judgment when performing this evaluation.

Right to Obtain Substantially All of the Benefits From the Use of the Asset

For a PPA to be considered a lease, the off-taker must also have the right to obtain substantially all of the economic benefits from the use of the generating asset throughout the period of use. Although the FASB did not define "economic benefits," the term as used in the new standard encompasses all economic benefits from the use of an asset, including products, by-products, and those benefits that may be realized through a subsequent transaction with a third party. Therefore, an off-taker will conclude that certain other benefits provided in a PPA (e.g., capacity, renewable energy credits, or steam) constitute economic benefits. An off-taker will have to consider how the receipt or nonreceipt of such additional benefits from the use of a facility affects the accounting for a particular contract. Note that tax attributes related to ownership of the asset are not considered economic benefits (e.g., investment tax credits and production tax credits).

Thinking It Through

Questions have arisen about whether production tax credits should be deemed economic benefits, given that they are tied to the use of the productive asset (as opposed to investment tax credits, which are tied to installed cost). We believe that all tax attributes should be excluded from the economic benefits test, as they all belong to the owner(s) of the asset and cannot be sold in a market transaction. This approach is consistent with the way outputs are determined today in the identification of leases under ASC 840.

Transportation and Storage Contracts

Contracts to transport or store gas or other fuel products will need to be evaluated under the new definition of a lease. To be considered a specified asset under the new leases standard, a capacity portion of a larger asset has to be physically distinct or have substantially all of the larger asset's capacity. Because the terms of pipeline and storage contracts vary significantly (e.g., regarding the rights to a percentage of an asset's capacity or other economic benefits), P&U entities need to evaluate such contracts to determine whether to account for them under the guidance on leases, revenue recognition (suppliers), derivatives, or other U.S. GAAP.

In addition, P&U companies should also be aware that the new standard specifically highlights by way of example that a pipeline lateral that is dedicated to one user is a distinct portion of a larger asset that would be considered an identified asset. On the surface, this seems to capture any arrangements for transportation service that include dedicated stretches of service — most notably those involving infrastructure connecting a single customer (e.g., a commercial or industrial customer) to the natural gas pipeline in a utility's territory. These are commonly called last-mile scenarios in reference to the connection to the customer site using infrastructure that is effectively dedicated. P&U entities should consider the potential ramifications of this guidance for elements of their distribution systems, including wires, meters, and other equipment that serve a single customer. The lateral example that was included in the final ASU was never formally subject to public exposure. Accordingly, we anticipate further discussion between affected companies and the FASB to obtain clarity on the intent of the requirement and to understand its application to different fact patterns. While the lateral example is highlighted as an identified asset, it will also be necessary to assess control over the infrastructure before concluding that these assets are subject to lease accounting.

Thinking It Through

The guidance that supports laterals as being identified assets could have much broader implications for P&U entities. In particular, it raises a question about whether certain P&U electric transmission and distribution assets would represent identified assets. For example, an analogy could be made that power lines connecting one customer to the broader distribution system would represent identified assets under the new standard. Similarly, questions could be raised about whether meters and other equipment maintained at a customer location would be considered identified assets (as indicated above, an assessment of control would also be required, and this aspect is not presupposed by ASC 842). From a practical standpoint, equipment supporting at-will customers will probably not be subject to a lease because of the lack of a term arrangement between the utility and the customer. However, where term arrangements do exist (e.g., with some commercial and industrial customers), this guidance could be relevant.

Section 8 — Income Tax Update: Other Developments

This section summarizes FASB, FERC, and IRS pronouncements related to accounting for income taxes as well as federal and state income tax developments affecting the financial and regulatory reporting of income taxes. The accounting for Treasury grants, ITCs, and PTCs is discussed in Section 9. Tax accounting developments related to share-based payments are discussed in Employee Share-Based Payment Accounting Improvements in Section 4 .

Normalization

Correction of Deferred Tax Accounting Errors

In January 2016, the IRS, through its PLR process, addressed the correction of deferred tax accounting errors. Specifically, the utility in PLR 201603017 became aware of deferred tax errors embedded in its legacy accounting system while installing a "more robust" new accounting system. The previously unrecognized errors resulted in (1) a lower amount of deferred tax expense than would have been calculated if the errors had not been present and (2) a lower DTL balance. The net effect of these errors was a lower revenue requirement.

The utility sets rates for a five-year period that are based initially on a traditional rate case and adjusted for subsequent years by the application of a formula. The utility identified the deferred tax accounting error during one of the years subject to adjustment by using the prescribed formula and believed that it was unable to have the error recognized and corrected by its commission during the five-year period. Instead, the utility calculated the amount by which the benefits of accelerated depreciation were being flowed through to ratepayers beginning in the year tested and created an entry on its regulatory books in this amount. In its next general rate case, the utility sought to amortize the amount of unfunded deferred tax expense that it had measured since its identification of the accounting error, but the commission staff proposed that computation of deferred tax in the new system should be prospective without any recovery of the regulatory asset that the utility had recorded.

The IRS ruled in PLR 201603017 that the utility's ratemaking and accounting procedures that resulted in the partial flow through of the tax benefits of accelerated depreciation were not inconsistent with the normalization requirements and hence not in violation of the normalization rules so long as the utility implemented corrective measures that were adequate under those rules. The IRS held that the proposal by the commission staff to use the new system solely to calculate deferred tax expense prospectively would not adequately correct the inadvertent violation of the normalization rules. However, the utility's proposal to amortize the regulatory asset and to use the new system to calculate deferred tax expense prospectively would constitute an adequate corrective measure under the normalization rules if adopted by the commission.

Effect of Repairs-Related Change in Tax Method of Accounting

The IRS addressed In PLR 201640005 the application of the deferred tax normalization requirements to a change in tax method of accounting under IRS Revenue Procedure ("Rev. Proc.") 2011-43 related to the unit of property for electric transmission and distribution plant in the determination of whether an expenditure with respect to such plant is a deductible repair or a capitalizable and depreciable improvement for federal income tax purposes.

The utility In PLR 201640005 used future test years to set rates for three-year periods. The utility changed its tax method of accounting after rates had been set for a three-year rate cycle on the basis of a forecasted repairs-related book/tax difference that was lower than the actual repairs-related book/tax difference under its new tax method of accounting. The utility employed the flow-through method of accounting for deferred taxes related to repairs-related book/tax differences arising under its historical tax method of accounting as well as its new tax method, including the Section 481(a) cumulative catch-up adjustment. The incremental repairs deductions were not incorporated into the rates in effect at the time of the change in the tax method of accounting; however, in accordance with flow-through accounting, they reduced regulatory tax expense, increased net income, and increased the tax-related regulatory asset.

During the rate proceeding for the next rate cycle, a consumer advocate raised a concern and proposed a ratemaking adjustment, asserting that the failure to incorporate the incremental tax benefits in the prior rate cycle will result in a detriment to ratepayers in future years. The consumer advocate estimated the future detriment as the sum of both of the following:

- The forecasted incremental tax expense for which ratepayers would be charged when the repair timing differences that flowed during the prior rate cycle reverse in the future.
- The absence of the accumulated deferred federal income taxes that would have existed had the repair accounting method election prescribed by Rev. Proc. 2011-43 not been made (i.e., the costs deducted as repair under the new method would have been capitalized and depreciated for tax purposes, thereby producing incremental accumulated deferred federal income taxes).

The final rate order included a rate base offset based on the "net present value of future excess costs to ratepayers resulting from Taxpayer's proposed ratemaking treatment for the repair deduction as compared to the ratemaking tax treatment assumption in place at the time of the applicable repairs."

The IRS ruled that the rate base offset related to the repair deductions was not calculated on the basis of any element of the depreciation deduction and thus did not violate the deferred tax normalization requirements.

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 DTA for the portion of an NOL or MTC carryforward attributable to accelerated depreciation must be included in rate base.
- Whether the full amount of the depreciation-related DTL may reduce rate base despite the existence of an NOL carryforward (i.e., when the DTA for the portion of an NOL carryforward attributable to accelerated depreciation is considered a component of the depreciation-related DTL for ratemaking purposes notwithstanding its classification as a DTA for financial, and often regulatory, reporting purposes).
- How to compute the depreciation-related portion of 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 and 2015, the IRS released seven PLRs addressing the application of the deferred tax normalization requirements when an NOL carryforward exists. The 2014 rulings consist of the following:

- PLR 201418024.
- PLR 201436037.
- PLR 201436038.
- PLR 201438003.

The 2015 rulings are summarized as follows:

- *PLR 201519021* — The utility subsidiary in PLR 201519021 forecasted that it would incur an NOL resulting in an NOL carryforward in its test period. In its rate proceeding, the DTL used to reduce rate base was reduced by the amount of the DTA for the NOL carryforward. The commission issued an order holding that while it was inappropriate to include the DTA for the NOL carryforward in rate base, the commission intends to comply with the normalization requirements and will allow the utility to seek rate adjustments if the utility obtains a PLR 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.

  In PLR 201519021, the IRS stated that the deferred tax normalization 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." Accordingly, 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.

- *PLR 201534001* — The utility subsidiary in PLR 201534001 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 attorney general argued against the utility's proposed calculation. Subsequently, the commission issued a final order in which it agreed with the utility but concluded that the ambiguity in the relevant normalization regulations warranted an assessment of the issue by the IRS.

  In PLR 201534001, the IRS stated that the deferred tax normalization 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 noted that the utility subsidiary's use of the "last dollars deducted" 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 addition, the IRS ruled that use of any method other than the "last dollars deducted" method would be inconsistent with the normalization requirements.

- *PLR 201548017* — The utility subsidiary in PLR 201548017 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. Various participants in the rate proceeding argued against the utility's proposed calculation. One proposal was to make an offsetting reduction to the utility's income tax expense element of service if the utility were to be allowed to reduce the DTL balance by the DTA balance. The utility law judge upheld the utility's position with respect to the NOL carryforward and ordered the utility to seek a ruling on this matter.

  In PLR 201548017, the IRS stated that the deferred tax normalization 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 "last dollars deducted" method employed 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 use of any method other than the "last dollars deducted" method would be inconsistent with the normalization requirements. In addition, the IRS ruled that reduction of the utility's tax expense element of cost of service specifically to mitigate the effect of the normalization rules in the calculation of the DTL and NOL carryforward would, in effect, flow through the tax benefits of accelerated depreciation deductions to ratepayers even though the utility has not yet realized such benefits. Noting that taxpayers generally may not adopt any accounting treatment that directly or indirectly circumvents the normalization rules, the IRS further ruled that the "offsetting reduction" would violate the normalization rules.

Future Test Periods

The deferred tax normalization regulations contain rules applicable to the computation of the maximum amount of deferred tax reserve excludable from rate base when rates are set with reference to future test periods. Five PLRs issued in 2015 provide guidance on how to apply these rules to annual formula rates with true-up adjustments. One of these rulings also addresses stand-alone rate adjustments for the recovery of certain costs of public utility property without a full base rate proceeding.

In these PLRs — PLRs 201531010, 201531011, 201531012, 201532018, and 201541010 — the IRS specifically addressed how the deferred tax normalization rules apply to FERC formula rates, reset annually with true-up adjustments, for electric transmission businesses.

The FERC-approved formula uses a rate-of-return, cost-of-service model. Before the year in which the rates become effective (e.g., by September 1 of year 1), a utility estimates its revenue requirement for the following calendar year, the service year (i.e., year 2), partly on the basis of the facilities in service at that time and expected to be placed in service during the service year and a FERC-approved rate of return. Rates charged during the service period are based on this projected revenue requirement. The formula rate template also contains a "true-up" mechanism under which a utility compares (1) its actual revenue requirement determined on the basis of amounts reported in its FERC Form No. 1 for the service year filed by April of year 3 (i.e., actual costs incurred and actual rate base amounts) with (2) its revenues billed for the service year. If billed revenue is greater than the actual revenue requirement for the service year, the overcollection is refunded in customer bills within two years of the service year (i.e., by the end of year 4). If billed revenue is less than the actual revenue requirement for the service year, the undercollection is collected two years after the service year. For both undercollections and overcollections, a carrying charge computed with reference to FERC's standard refund interest rate is imposed.

In computing their projected and actual annual revenue requirements under their FERC-approved formulas, the taxpayers in the PLRs calculate average rate base. All elements of average rate base are computed on the basis of the same test period and the same service year. The taxpayers compute average rate base by using monthly averages for plant balances, including accumulated depreciation. For this purpose, depreciation begins when the asset is placed in service. To calculate certain other elements of average rate base, including accumulated deferred income taxes, the taxpayers use averages of the beginning- and end-of-year balances. The taxpayers reduce their gross rate base amounts by forecasted accumulated deferred income tax balances not computed in accordance with the proration formula required by Treas. Regs. Section 1.167(l)-1(h)(6) for future test periods. In periods of increasing accumulated deferred income tax balances, application of the proration formula would decrease average accumulated deferred income taxes, increase average rate base, and increase the revenue requirement. The deferred tax computations are pursuant to the provisions of the taxpayers' FERC-approved templates.

The IRS held that the computations of average rate base by the taxpayers with reference to 13-month averages for plant and accumulated depreciation for a given service year and simple averages of the beginning- and end-of-year balances for accumulated deferred income taxes for the same service years comply with the consistency requirement of the normalization rules for accelerated depreciation under IRC Section 168(i)(9)(B). For this aspect of the normalization requirements to be satisfied, there must be consistency in the treatment of costs for rate base, regulated depreciation expense, tax expense, and accumulated deferred income taxes. The IRS explained that the taxpayers computed the averages of rate base, depreciation expense, and accumulated deferred income taxes in a consistent fashion in terms of averaging over the same period. Although there are minor differences in the convention used to average all elements of rate base, the IRS concluded that for purposes of the deferred tax consistency requirement, it is sufficient that both depreciation expense and accumulated deferred income taxes are (1) determined by averaging and (2) determined over the same period.

The IRS also held in the five PLRs that the computations of accumulated deferred income taxes for the projected revenue requirement (computed with reference to a test period ending after the effective date of rates) involve future test periods requiring application of the proration formula to comply with the normalization requirements. In PLRs 201531010, 201531011, 201531012, and 201532018, the IRS ruled that the computation of accumulated deferred income taxes for purposes of calculating average rate base without application of the proration rules for future test periods for the taxpayer's actual revenue requirement used for the true-up mechanism (determined after the end of the service period) complies with the deferred tax normalization requirements because the test year is no longer a future test period in this context.

In PLR 201541010, the IRS similarly held that the true-up component is determined by reference to a purely historical period, and that there is no need to use the proration formula to calculate the differences between the projected and actual accumulated deferred income tax balances during the period. However, the IRS also indicated in PLR 201541010 that when the true-up is calculated, (1) the proration formula applies to the original projection amount, but (2) the actual amount added to the accumulated deferred income tax balance over the test year is not modified by application of the proration formula.

In PLR 201541010, the IRS addressed a revision by the commission to adjust the utility's already approved cash working capital allowance specifically to mitigate the effect of using the proration method. The IRS indicated that in general, taxpayers may not adopt any accounting treatment that directly or indirectly circumvents the normalization rules. The IRS held that in this situation, an adjustment to eliminate from the cash working capital allowance any provision for accelerated depreciation-related accumulated deferred income taxes if the proration method is employed conflicts with the normalization rules.

Finally, the IRS held that if the taxpayers take specific corrective actions prescribed in the PLRs, and assuming compliance by FERC with methods described in the PLRs on a prospective basis, sanctions for violation of the deferred tax normalization requirements involving disallowance of accelerated depreciation would not apply despite the taxpayers' historical use of the method held not to comply with the normalization requirements.

Definition of "Public Utility Property" and Scope of Application of the Normalization Requirements

The deferred tax normalization requirements and the ITC normalization requirements apply to "public utility property" as defined in each of the operative statutory provisions and regulations issued thereunder. The definitions are consistent with each other, but there are wording differences. The IRS has ruled in the past and ruled again in PLR 201544018 and PLR 201619005 that the definition of public utility property is the same for purposes of the ITC and depreciation and that if property is public utility property for purposes of the ITC, it is also public utility property for purposes of depreciation. The determination of whether property is public utility property for normalization purposes is based on whether the property is used in a public utility activity (e.g., the furnishing or sale of electrical energy) and whether the rates for such furnishing or sale are established or approved by a public utility commission or similar body on a rate-of-return basis.

The utility in PLR 201544018 will enter into a contract with a U.S. governmental agency for the entire output of a solar generation facility over a multiyear period with an option for an extension. The rates to be paid for the electricity under the contract will be determined in negotiations between the parties. Because the rates are determined solely by negotiations between a buyer and a seller rather than being established or approved by a governmental entity through a regulatory process on a rate-of-return basis, the rates are not "established or approved" within the meaning of the normalization rules notwithstanding that the buyer is a U.S. governmental agency. Therefore, the generation facility is not public utility property for normalization purposes.

The IRS indicated in PLR 201544018 that it did not express or imply an opinion about whether the contract to sell electricity constitutes a service contract or a lease, or whether the utility is the owner of the facility for federal income tax purposes.

The utility in PLR 201619005 requested guidance on whether the normalization requirements apply to the portions of solar generation facilities with energy output allocated to customer groups at rates set under three pricing-specific arrangements. The IRS ruled that the portion of the facilities with pricing set under a market index rate adjustment clause subject to the regulatory jurisdiction of one of the utility's commissions does not constitute public utility property (i.e., is not subject to the normalization requirements) because rates are not set on a rate-of-return basis. The IRS held that the portion of the facilities with pricing set by means of bilateral negotiations between the utility and nonjurisdictional customers does not constitute public utility property (i.e., is not subject to the normalization requirements) because rates are not established or approved by a public utility commission and are not determined on a rate-of-return basis. Finally, the IRS ruled that the portion of the facilities allocated to wholesale customers in one of the utility's regulatory jurisdictions, with pricing set by negotiation or the wholesale market index (or both) and approved by the commission, does not constitute public utility property (i.e., is not subject to the normalization requirements) because rates are not set on a rate-of-return basis.

The IRS indicated in PLR 201619005 that it did not express or imply an opinion about (1) whether the contract to sell electricity constitutes a service contract or a lease, (2) whether the utility is the owner of the facility for federal income tax purposes, or (3) the classification of the property for purposes of depreciable recovery period.

Like-Kind Exchanges

The utilities in PLR 201532024 and PLR 201532025 exchanged public utility property subject to the normalization requirements in a transaction that resulted in deferral under IRC Section 1031 of a significant portion of the taxable gain otherwise recognized by each taxpayer. Thus, for each utility, the tax basis of each relinquished property became the tax basis of replacement property (i.e., substituted basis), adjusted for the amount of gain recognized.

For regulatory accounting purposes, the replacement property was recorded at the same regulatory book value as the relinquished property. Before the exchange, DTL balances reflected the deferral of federal income taxes attributable to claiming accelerated depreciation with respect to the relinquished property as required by the normalization rules.

The utilities requested guidance on determining the appropriate amount of DTL balances for ratemaking and regulatory reporting purposes under the deferred tax normalization requirements as a result of the exchange. The IRS held that (1) the utilities' DTL balances with respect to the relinquished property must be adjusted to reflect the dispositions and (2) the required adjustment is the removal from the utilities' regulated books of account of the DTL balances with respect to the relinquished property.

The IRS also ruled that it would be inconsistent with the normalization requirements to recognize for ratemaking purposes a DTL attributable to the replacement property immediately after the exchange.

Balance Sheet Classification of Deferred Taxes

In November 2015, the FASB issued ASU 2015-17 (as part of its simplification initiative aimed at reducing the cost and complexity of certain aspects of U.S. GAAP), which modifies ASC 740-10-45 and requires entities to present all deferred taxes as noncurrent assets or noncurrent liabilities on a classified balance sheet.

Classification of all deferred taxes as noncurrent eliminates the requirement to allocate a valuation allowance on a pro rata basis between gross current and noncurrent DTAs, which was an issue that FASB constituents had asked the Board to address as part of its simplification initiative. However, jurisdictional netting will still be required under the ASU.

Companies should continue their historical use of the various DTA and DTL accounts included in the Uniform System of Accounts in their FERC reporting because the U.S. GAAP deferred tax netting rules do not apply for FERC reporting purposes.

The ASU is effective for public business entities for annual periods beginning after December 15, 2016, and interim periods within those annual periods. For all other entities, the ASU is effective for annual periods beginning after December 15, 2017, and interim reporting periods within annual reporting periods beginning after December 15, 2018. Earlier application is permitted for all entities as of the beginning of an interim or annual reporting period. The amendments in the ASU may be applied either prospectively to all DTLs and DTAs or retrospectively to all periods presented.

For more information about the ASU, see Deloitte's November 30, 2015, *Heads Up*.

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 as qualified affordable housing projects (QAHPs) and provides disclosure requirements for entities with such investments regardless of whether the entities modify their accounting. Under the ASU, entities can apply, as an accounting policy election, a proportional amortization method to qualified affordable housing project investments (QAHPIs) 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 QAHPIs if 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 a QAHPI 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 certain information described below.

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 was effective for annual periods beginning after December 15, 2014, and interim periods therein. For nonpublic entities, the ASU was effective for annual periods beginning after December 15, 2014, and interim periods within annual periods beginning after December 15, 2015. Early adoption was permitted for all entities.

Entities that applied the effective-yield method to account for QAHPIs under the alternative in ASC 323-740 are permitted to continue doing 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 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 do not elect the proportional amortization method, only the disclosure-related amendments in the ASU apply. Under ASC 323-740-50-1 (added by the ASU), a reporting entity that invests in a qualified affordable housing project is required to disclose information that enables users of its financial statements to understand:

- "The nature of its investments in qualified affordable housing projects."
- "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."

To meet the objectives of these disclosure requirements, a reporting entity may consider disclosing:

- "The amount of affordable housing tax credits and other tax benefits recognized during the year."
- "The balance of the investment recognized in the statement of financial position."
- "For qualified affordable housing project investments accounted for using the proportional amortization method, the amount recognized as a component of income tax expense (benefit)."
- "For qualified affordable housing project investments accounted for using the equity method, the amount of investment income or loss included in pretax income."
- "Any commitments or contingent commitments . . . , including the amount of equity contributions that are contingent commitments . . . and the year or years in which contingent commitments are expected to be paid."
- "The amount and nature of impairment losses during the year resulting from the forfeiture or ineligibility of tax credits or other circumstances."

Section 9 — Renewable Energy: Accounting for Renewable Energy Certificates

Production Tax Credits, Investment Tax Credits, and Treasury Grants

Introduction

Entities calculate PTCs under IRC Section 45 by using stated rates (e.g., 2016 wind production at 2.3 cents per kWh) multiplied by kWh generated during each of the first 10 years of operation. The American Taxpayer Relief Act of 2012 modified the rules for PTC eligibility by changing the termination date for the credit from placed-in-service deadlines to a "begun construction" standard. The Tax Increase Prevention Act of 2014, enacted in December 2014, extended PTC eligibility to qualified facilities, including wind generation plants, whose construction began before January 1, 2015. The Protecting Americans From Tax Hikes Act of 2015 (the "PATH Act"), enacted in December 2015, further extended the termination dates for PTC eligibility. Under current tax law, for most types of facilities eligible for PTCs, construction of the plant must begin before January 1, 2017, for the plant to be eligible for PTCs. However, the termination dates for wind generation plants are based on the following phase-out schedule:

- Full PTC rate for plants with construction beginning before January 1, 2017.
- 80 percent of the PTC rate for plants with construction beginning after December 31, 2016, but before January 1, 2018.
- 60 percent of the PTC rate for plants with construction beginning after December 31, 2017, but before January 1, 2019.
- 40 percent of the PTC rate for plants with construction beginning after December 31, 2018, but before January 1, 2020.

The energy credit under IRC Section 48 is an ITC available for certain renewable energy facilities generally subject to termination dates based on when construction begins. Entities calculate ITCs by using stated rates (e.g., 30 percent for fuel cells and solar generation property, 10 percent for geothermal electric generation property) multiplied by the tax basis of the eligible 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. Under current tax law, for most types of facilities eligible for ITCs, construction of the plant must begin before January 1, 2017, for the plant to be eligible for ITCs. However, the termination dates for solar generation plants are based on the following phase-out schedule:

- 30 percent ITC for plants with construction beginning before January 1, 2020.
- 26 percent ITC for plants with construction beginning after December 31, 2019, but before January 1, 2021.
- 22 percent ITC for plants with construction beginning after December 31, 2020, but before January 1, 2022.
- 10 percent ITC for plants with construction beginning (1) after December 31, 2021, or (2) before January 1, 2022, but not placed in service before January 1, 2024.

The American Recovery and Reinvestment Act of 2009 (the "Recovery Act") provides an irrevocable election under IRC Section 48(a)(5) that allows entities to claim a 30 percent ITC instead of a PTC for most PTC-eligible facilities placed in service after December 31, 2008, as long as no PTC has been claimed for such property. The PATH Act extended the credit termination dates for most PTC-eligible facilities for which an ITC is elected such that PTC-eligible facilities are generally eligible for PTCs or ITCs to the extent that construction begins before January 1, 2017. However, the ITC-in-lieu-of-PTC termination dates for wind generation plants are based on the following phase-out schedule:

- 30 percent ITC for plants with construction beginning before January 1, 2017.
- 24 percent ITC for plants with construction beginning after December 31, 2016, but before January 1, 2018.
- 18 percent ITC for plants with construction beginning after December 31, 2017, but before January 1, 2019.
- 12 percent ITC for plants with construction beginning after December 31, 2018, but before January 1, 2020.

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 otherwise applicable under then-current tax law 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's Web site. In accordance with the Balanced Budget and Emergency Deficit Control Act of 1985, as amended, payments issued under Section 1603 of the Recovery Act for specified energy property in lieu of tax credits are subject to sequestration. The sequestration reduction rate will be applied unless and until a law is enacted that cancels or otherwise affects the applicant, at which time the sequestration reduction rate is subject to change. As a result, every award made to a Section 1603 applicant on or after October 1, 2016, and on or before September 30, 2017, will be reduced by 6.9 percent, irrespective of when the application was received by the Treasury. The sequestration rates for the fiscal years ending September 30, 2016, September 30, 2015, and September 30, 2014, were 6.8 percent, 7.3 percent, and 7.4 percent, respectively.

PTC and ITC in Lieu of PTC

Through a series of notices, the IRS has provided guidance regarding the Begun Construction guidance described above. The subsequent notices were issued as a result of extensions of the statutory termination dates and in response to taxpayers' requests for clarification and relief.

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 American Taxpayer Relief Act of 2012 (the construction of the facility must have begun before January 1, 2014 (subsequently extended by legislation enacted in 2014 and 2015)). 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) [of Notice 2013-29]) 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) [of Notice 2013-29]) 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 test) 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 test 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 Notice 2013-29's list of activities that constitute physical work is not all-inclusive and that any one of the activities in Notice 2013-29 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 Section 4.04(3) of 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 test.

To qualify for the PTC or ITC, a taxpayer that begins construction does not need to be the same taxpayer that 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 test 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 test, 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 that 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 (energy, procurement, construction) agreements, should include recordkeeping requirements to demonstrate progress.

In March 2015, IRS Notice 2015-25 extended the safe harbor for the continuous construction test and continuous efforts test to allow certain facilities, including wind generation plants, to be eligible for the credit if (1) construction of the facilities began before January 1, 2015, and (2) the facilities are placed in service before January 1, 2017. Specifically, Section 3 of the notice states:

> Thus, if a taxpayer begins construction on a facility prior to January 1, 2015, and places the facility in service before January 1, 2017, the facility will be considered to satisfy the Continuous Construction Test (for purposes of satisfying the Physical Work Test) or the Continuous Efforts Test (for purposes of satisfying the Safe Harbor), regardless of the amount of physical work performed or the amount of costs paid or incurred with respect to the facility after December 31, 2014 and before January 1, 2017.

IRS Notice 2016-31, issued in May 2016, provides additional guidance on the Begun Construction standard for PTCs and ITCs in lieu of PTCs. In a manner consistent with the PATH Act's multiyear extension of the Begun Construction deadline, Notice 2016-31 extends the safe harbor for the continuous construction criterion and continuous efforts criterion to allow certain facilities to be considered to satisfy the applicable requirement if a taxpayer places a facility in service during a calendar year that is no more than four calendar years after the calendar year during which construction of the facility began. Notice 2016-31 prohibits a taxpayer from relying on the physical work test and the safe harbor threshold in alternating calendar years to satisfy the Begun Construction requirement or the applicable continuity requirement.

Notice 2016-31 reiterates that multiple facilities that are operated as part of a single project (along with any property, such as a computer control system, that serves some or all such facilities) may be treated as a single facility under the Begun Construction requirement (the "Aggregation Rule"). Notice 2016-31 requires that the taxpayer make its Aggregation Rule determination under the Begun Construction requirement in the calendar year during which the last of the multiple facilities is placed in service.

In addition, Notice 2016-31 indicates that multiple facilities that are operated as part of a single project and treated as a single facility in the determination of whether construction of a facility has begun may subsequently be disaggregated and treated as multiple separate facilities in the evaluation of whether a facility satisfies the applicable continuity requirement (the "Disaggregation Rule"). Disaggregated facilities placed in service before the end of the four-year continuity safe harbor will be eligible for this safe harbor. The remaining disaggregated facilities may satisfy the applicable continuity requirement under a facts-and-circumstances determination. This provision provides additional flexibility to developers working on large projects with long construction schedules.

Further, Notice 2016-31 revises Notice 2013-29's nonexclusive list of construction disruptions that will not be considered as indicating that a taxpayer has failed to remain in compliance with the applicable continuity requirement and gives examples of additional permissible disruptions.

IRS Notice 2016-34, issued in May 2016, publishes the inflation adjustment factor and reference prices for calendar year 2016 for the renewable electricity production credit and the refined coal production credit under IRC Section 45. The notice specifies that the inflation adjustment factor for qualified energy resources and refined coal was 1.5556 and that the reference price for facilities producing electricity from wind was 4.50 cents per kWh. Further, the notice states that the PTC rate for 2016 generation was 2.3 cents per kWh on the sale of electricity produced from the qualified energy resources of wind, closed-loop biomass, geothermal energy, and solar energy and 1.2 cents per kWh on the sale of electricity produced from open-loop biomass facilities, small irrigation power facilities, landfill gas facilities, trash facilities, qualified hydropower facilities, and marine and hydrokinetic energy facilities.

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. Depending on certain attributes, ITCs claimed with respect to a facility that is eligible for a Section 1603 grant may 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.

There is no definitive guidance on balance sheet presentation for an ITC eligible for a Section 1603 grant. In practice, the related balances have been deferred on the balance sheet, either as a reduction to the book property basis or as a deferred credit (not as a deferred tax credit). Such accounting is consistent with IAS 20. Some entities have applied IAS 20 in practice because there is no specific U.S. GAAP guidance on accounting for government grants. Under this approach, 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 U.S. GAAP, the excess rate reduction (a timing difference between U.S. 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 situation in which the SEC staff indicated that it would not object to a company's establishment of an accounting policy under which the company would account for the cash grants by analogy to ASC 450 and, more specifically, to the guidance in ASC 450 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 for which recognition is delayed because of insufficient taxable income. By entering into structures and allocating renewable energy tax benefits to investors, these entities are able to generate cash flows immediately by receiving cash in exchange for the tax 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 resulting from the investment. Modified accelerated cost recovery system (MACRS) depreciation, including bonus depreciation, and PTCs are examples of these tax benefits. Consequently, renewable energy 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 sufficient taxable income to monetize the tax benefits. Since the inception of structures, these investors have evolved from the typical investment banks and insurance companies to foreign investors — which 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 ample taxable income to use the 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 tax credits and tax depreciation that it will be unable to use, 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 Rev. Proc. 2007-65 (herein referred to as "traditional structures"). Issued in November 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 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 safe harbor treatment of allocations described in Rev. Proc. 2007-65 specifically applies only to wind partnerships with PTCs, the criteria of this revenue procedure 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 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:
>
> a. All sales of real estate, including real estate with property improvements or integral equipment. The terms *property improvements* and *integral equipment* as they are used in this Subtopic refer to any physical structure or equipment attached to the real estate that cannot be removed

> and used separately without incurring significant cost. Examples include an office building, a manufacturing facility, a power plant, and a refinery.
>
> b. Sales of property improvements or integral equipment subject to an existing lease of the underlying land should be accounted for in accordance with paragraphs 360-20-40-56 through 40-59.
>
> c. The sale or transfer of an investment in the form of a financial asset that is in substance real estate.

On the basis of the guidance in ASC 360-20-15-4 through 15-8, a renewable energy project 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:
>
> a. The profit is determinable, that is, the collectibility of the sales price is reasonably assured or the amount that will not be collectible can be estimated.
>
> b. The earnings process is virtually complete, that is, the seller is not obliged to perform significant activities after the sale to earn the profit.

If 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.

A renewable energy entity should evaluate the effect that the adoption of ASC 606 will have on the accounting for traditional structures. ASC 606 is effective for public entities for fiscal years beginning after December 15, 2017, including interim reporting periods therein, and for all other entities for fiscal years beginning after December 15, 2018, and interim reporting periods within annual reporting periods beginning after December 15, 2019.

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 forms 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 and regulations affecting the industry as a whole (e.g., the CSAPR). 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 should 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

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 U.S. 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 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 [U.S.] 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 HLBV method is a balance-sheet-oriented approach for determining the allocation of U.S. GAAP equity and income/loss. Under this method, U.S. 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 U.S. 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 U.S. 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 in such a way 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 "[i]f 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 of IAS 32, which states that a "financial instrument 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, ASC 360-20, ASC 360-970, ASC 805-10, and ASC 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 the tests are 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

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Appendix B — Other Resources and Upcoming Events

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Events

Deloitte Utility Tax Training Seminars
March 21–22, 2017 | Los Angeles, California

For more information, please contact: USEnergyTaxSeminars@deloitte.com.

Deloitte Oil and Gas Conference
September 19, 2017 | Houston, Texas

For more information, please contact: OilandGasConference@deloitte.com.

Financial Reporting for Taxes Training
December 5–9, 2017 | Las Vegas, Nevada

For more information, please contact: USEnergyTaxSeminars@deloitte.com.

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Appendix C — Titles of Standards and Other Literature

The following are the titles of standards and other literature mentioned in this publication:

AICPA

AT Section 101, "Attest Engagements"

AT Section 201, "Agreed-Upon Procedures Engagements"

FASB ASUs

ASU 2017-01, *Business Combinations (Topic 805): Clarifying the Definition of a Business*

ASU 2016-18, S*tatement of Cash Flows (Topic 230): Restricted Cash* — a consensus of the FASB Emerging Issues Task Force

ASU 2016-17, *Consolidation (Topic 810): Interests Held Through Related Parties That Are Under Common Control*

ASU 2016-16, *Income Taxes (Topic 740): Intra-Entity Transfers of Assets Other Than Inventory*

ASU 2016-15, *Statement of Cash Flows (Topic 230): Classification of Certain Cash Receipts and Cash Payments* — a consensus of the Emerging Issues Task Force

ASU 2016-13, *Financial Instruments — Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments*

ASU 2016-12, *Revenue From Contracts With Customers (Topic 606): Narrow-Scope Improvements and Practical Expedients*

ASU 2016-11, *Revenue Recognition (Topic 605) and Derivatives and Hedging (Topic 815): Rescission of SEC Guidance Because of Accounting Standards Updates 2014-09 and 2014-16 Pursuant to Staff Announcements at the March 3, 2016 EITF Meeting (SEC Update)*

ASU 2016-10, *Revenue From Contracts With Customers (Topic 606): Identifying Performance Obligations and Licensing*

ASU 2016-09, *Compensation — Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting*

ASU 2016-08, *Revenue From Contracts With Customers (Topic 606): Principal Versus Agent Considerations (Reporting Revenue Gross Versus Net)*

ASU 2016-07, *Investments — Equity Method and Joint Ventures (Topic 323): Simplifying the Transition to the Equity Method of Accounting*

ASU 2016-06, *Derivatives and Hedging (Topic 815): Contingent Put and Call Options in Debt Instruments* — a consensus of the Emerging Issues Task Force

ASU 2016-05, *Derivatives and Hedging (Topic 815): Effect of Derivative Contract Novations on Existing Hedge Accounting Relationships* — a consensus of the Emerging Issues Task Force

ASU 2016-03, *Intangibles — Goodwill and Other (Topic 350), Business Combinations (Topic 805), Consolidation (Topic 810), Derivatives and Hedging (Topic 815): Effective Date and Transition Guidance* — a consensus of the Private Company Council

ASU 2016-02, *Leases (Topic 842)*

ASU 2016-01, *Financial Instruments — Overall (Subtopic 825-10): Recognition and Measurement of Financial Assets and Financial Liabilities*

ASU 2015-17, *Income Taxes (Topic 740): Balance Sheet Classification of Deferred Taxes*

ASU 2015-16, *Business Combinations (Topic 805): Simplifying the Accounting for Measurement-Period Adjustments*

ASU 2015-14, *Revenue From Contracts With Customers (Topic 606): Deferral of the Effective Date*

ASU 2015-13, *Derivatives and Hedging (Topic 815): Application of the Normal Purchases and Normal Sales Scope Exception to Certain Electricity Contracts Within Nodal Energy Markets* — a consensus of the FASB Emerging Issues Task Force

ASU 2015-11, *Inventory (Topic 330): Simplifying the Measurement of Inventory*

ASU 2015-02, *Consolidation (Topic 810): Amendments to the Consolidation Analysis*

ASU 2014-18, *Business Combinations (Topic 805): Accounting for Identifiable Intangible Assets in a Business Combination* — a consensus of the Private Company Council

ASU 2014-16, *Derivatives and Hedging (Topic 815): Determining Whether the Host Contract in a Hybrid Financial Instrument Issued in the Form of a Share Is More Akin to Debt or to Equity* — a consensus of the FASB Emerging Issues Task Force

ASU 2014-15, *Presentation of Financial Statements — Going Concern (Subtopic 205-40): Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern*

ASU 2014-09, *Revenue From Contracts With Customers (Topic 606)*

ASU 2014-07, *Consolidation (Topic 810): Applying Variable Interest Entities Guidance to Common Control Leasing Arrangements* — a consensus of the Private Company Council

ASU 2014-03, *Derivatives and Hedging (Topic 815): Accounting for Certain Receive-Variable, Pay-Fixed Interest Rate Swaps — Simplified Hedge Accounting Approach* — a consensus of the Private Company Council

ASU 2014-02, *Intangibles — Goodwill and Other (Topic 350): Accounting for Goodwill* — a consensus of the Private Company Council

ASU 2014-01, *Investments — Equity Method and Joint Ventures (Topic 323): Accounting for Investments in Qualified Affordable Housing Projects* — a consensus of the FASB Emerging Issues Task Force

ASU 2010-20, *Receivables (Topic 310): Disclosures About the Credit Quality of Financing Receivables and the Allowance for Credit Losses*

FASB ASC Topics and Subtopics

ASC 210, *Balance Sheet*

ASC 230, *Statement of Cash Flows*

ASC 230-10, *Statement of Cash Flows: Overall*

ASC 235, *Notes to Financial Statements*

ASC 250, *Accounting Changes and Error Corrections*

ASC 250-10, *Accounting Changes and Error Corrections: Overall*

ASC 320, *Investments — Debt and Equity Securities*

ASC 321, *Investments — Equity Securities*

ASC 321-10, *Investments — Equity Securities: Overall*

ASC 323-10, *Investments — Equity Method and Joint Ventures: Overall*

ASC 323-740, *Investments — Equity Method and Joint Ventures: Income Taxes*

ASC 325, *Investments — Other*

ASC 325-40, *Investments — Other: Beneficial Interests in Securitized Financial Assets*

ASC 326-20, *Financial Instruments — Credit Losses: Measured at Amortized Cost*

ASC 326-30, *Financial Instruments — Credit Losses: Available-for-Sale Debt Securities*

ASC 330, *Inventory*

ASC 330-10, *Inventory: Overall*

ASC 350, *Intangibles — Goodwill and Other*

ASC 360, *Property, Plant, and Equipment*

ASC 360-10, *Property, Plant, and Equipment: Overall*

ASC 360-20, *Property, Plant, and Equipment: Real Estate Sales*

ASC 360-970, *Property, Plant, and Equipment: Real Estate — General*

ASC 405, *Liabilities*

ASC 405-20, *Liabilities: Extinguishments of Liabilities*

ASC 450, *Contingencies*

ASC 450-20, *Contingencies: Loss Contingencies*

ASC 450-30, *Contingencies: Gain Contingencies*

ASC 470-10, *Debt: Overall*

ASC 470-20, *Debt: Debt With Conversion and Other Options*

ASC 470-50, *Debt: Modifications and Extinguishments*

ASC 480, *Distinguishing Liabilities From Equity*

ASC 480-10, *Distinguishing Liabilities From Equity: Overall*

ASC 505-50, *Equity: Equity-Based Payments to Non-Employees*

ASC 605, *Revenue Recognition*

ASC 605-20, *Revenue Recognition: Services*

ASC 605-45, *Revenue Recognition: Principal Agent Considerations*

ASC 605-50, *Revenue Recognition: Customer Payments and Incentives*

ASC 606, *Revenue From Contracts With Customers*

ASC 610-20, *Other Income: Gains and Losses From the Derecognition of Nonfinancial Assets*

ASC 715, *Compensation — Retirement Benefits*

ASC 715-20, *Compensation — Retirement Benefits: Defined Benefit Plans — General*

ASC 718, *Compensation — Stock Compensation*

ASC 718-20, *Compensation — Stock Compensation: Awards Classified as Equity*

ASC 720, *Other Expenses*

ASC 720-15, *Other Expenses: Start-Up Costs*

ASC 740, *Income Taxes*

ASC 740-10, *Income Taxes: Overall*

ASC 805, *Business Combinations*

ASC 805-10, *Business Combinations: Overall*

ASC 805-20, *Business Combinations: Identifiable Assets and Liabilities, and Any Noncontrolling Interest*

ASC 810, *Consolidation*

ASC 810-10, *Consolidation: Overall*

ASC 815, *Derivatives and Hedging*

ASC 815-10, *Derivatives and Hedging: Overall*

ASC 815-15, *Derivatives and Hedging: Embedded Derivatives*

ASC 815-20, *Derivatives and Hedging: Hedging — General*

ASC 815-40, *Derivatives and Hedging: Contracts in Entity's Own Equity*

ASC 820, *Fair Value Measurement*

ASC 820-10, *Fair Value Measurement: Overall*

ASC 825, *Financial Instruments*

ASC 825-10, *Financial Instruments: Overall*

ASC 835, *Interest*

ASC 835-20, *Interest: Capitalization of Interest*

ASC 840, *Leases*

ASC 842, *Leases*

ASC 842-10, *Leases: Overall*

ASC 845-10, *Nonmonetary Transactions*

ASC 855, *Subsequent Events*

ASC 855-10, *Subsequent Events: Overall*

ASC 932-10, *Extractive Activities — Oil and Gas: Overall*

ASC 946, *Financial Services — Investment Companies*

ASC 960, *Plan Accounting — Defined Benefit Pension Plans*

ASC 962, *Plan Accounting — Defined Contribution Pension Plans*

ASC 965, *Plan Accounting — Health and Welfare Benefit Plans*

ASC 970-10, *Real Estate — General: Overall*

ASC 970-323, *Real Estate — General: Investments — Equity Method and Joint Ventures*

ASC 980, *Regulated Operations*

ASC 980-10, *Regulated Operations: Overall*

ASC 980-340, *Regulated Operations: Other Assets and Deferred Costs*

ASC 980-360, *Regulated Operations: Property, Plant, and Equipment*

ASC 980-405, *Regulated Operations: Liabilities*

ASC 980-480, *Regulated Operations: Leases*

ASC 980-482, *Regulated Operations: Leases*

FASB Proposed ASUs

Proposed ASU 2016-370, *I. Accounting for Certain Financial Instruments With Down Round Features and II. Replacement of the Indefinite Deferral for Mandatorily Redeemable Financial Instruments of Certain Nonpublic Entities and Certain Mandatorily Redeemable Noncontrolling Interests With a Scope Exception*

Proposed ASU 2016-360, *Compensation — Stock Compensation (Topic 718): Scope of Modification Accounting*

Proposed ASU 2016-310, *Derivatives and Hedging (Topic 815): Targeted Improvements to Accounting for Hedging Activities*

Proposed ASU EITF-16B, *Plan Accounting — Defined Benefit Pension Plans (Topic 960), Defined Contribution Pension Plans (Topic 962), Health and Welfare Benefit Plans (Topic 965): Employee Benefit Plan Master Trust Reporting* — a consensus of the Emerging Issues Task Force

Proposed ASU 2016-270, *Income Taxes (Topic 740): Disclosure Framework — Changes to the Disclosure Requirements for Income Taxes*

Proposed ASU 2016-250, *Other Income — Gains and Losses From the Derecognition of Nonfinancial Assets (Subtopic 610-20): Clarifying the Scope of Asset Derecognition Guidance and Accounting for Partial Sales of Nonfinancial Assets*

Proposed ASU 2016-230, *Intangibles — Goodwill and Other (Topic 350): Simplifying the Accounting for Goodwill Impairment*

Proposed ASU 2016-210, *Compensation — Retirement Benefits — Defined Benefit Plans — General (Subtopic 715-20): Changes to the Disclosure Requirements for Defined Benefit Plans*

Proposed ASU 2016-200, *Compensation — Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost*

Proposed ASU 2015-350, *Fair Value Measurement (Topic 820): Disclosure Framework — Changes to the Disclosure Requirements for Fair Value Measurement*

Proposed ASU 2015-340, *Government Assistance (Topic 832): Disclosures by Business Entities About Government Assistance*

Proposed ASU 2015-310, *Notes to Financial Statements (Topic 235): Assessing Whether Disclosures Are Material*

Proposed ASU 2015-280, *Investments — Equity Method and Joint Ventures (Topic 323): Simplifying the Equity Method of Accounting*

Other FASB Proposals

Proposed Concepts Statement 2015-300, *Conceptual Framework for Financial Reporting: Chapter 3: Qualitative Characteristics of Useful Financial Information*

Proposed Concepts Statement 2014-200, *Conceptual Framework for Financial Reporting: Chapter 8: Notes to Financial Statements*

Invitation to Comment 2012-220, *Disclosure Framework*

FASB Concepts Statement

CON 8, *Conceptual Framework for Financial Reporting*

EITF Issues

13-B, "Accounting for Investments in Qualified Affordable Housing Projects"

16-B, "Employee Benefit Plan Master Trust Reporting"

92-7, "Accounting by Rate-Regulated Utilities for the Effects of Certain Alternative Revenue Programs"

Private Company Council Literature

PCC Issue No. 15-02, "Applying Variable Interest Entity Guidance to Entities Under Common Control"

SEC C&DI Topics

Exchange Act Sections 13(d) and 13(g) and Regulation 13D-G Beneficial Ownership Reporting

FAST Act

Non-GAAP Financial Measures

Regulation AB and Related Rules

Regulation S-K

Securities Act Forms

Securities Act Rules

Securities Act Sections

SEC Concept Release

33-10064, *Business and Financial Disclosure Required by Regulation S-K*

SEC Final Rules

34-78167, *Disclosure of Payments by Resource Extraction Issuers*

33-10075, *Changes to Exchange Act Registration Requirements to Implement Title V and Title VI of the JOBS Act*

SEC Interim Final Rules

34-77969, *Form 10-K Summary*

33-10003, *Simplification of Disclosure Requirements for Emerging Growth Companies and Forward Incorporation by Reference on Form S-1 for Smaller Reporting Companies*

SEC Order

34-78041, *Order Granting Limited and Conditional Exemption Under Section 36(a) of the Securities Exchange Act of 1934 From Compliance With Interactive Data File Exhibit Requirement in Forms 6-K, 8-K, 10-Q, 10-K, 20-F and 40-F to Facilitate Inline Filing of Tagged Financial Data*

SEC Proposed Rules

33-10110, *Disclosure Update and Simplification*

33-10107, *Amendments to Smaller Reporting Company Definition*

Other SEC Proposal

33-10198, *Request for Comment on Subpart 400 of Regulation S-K Disclosure Requirements Relating to Management, Certain Security Holders and Corporate Governance Matters*

SEC Division of Corporation Finance *Financial Reporting Manual*

Topic 1, "Registrant's Financial Statements"

Topic 2, "Other Financial Statements Required"

Topic 5, "Smaller Reporting Companies"

Topic 8, "Non-GAAP Measures of Financial Performance, Liquidity, and Net Worth"

Topic 10, "Emerging Growth Companies"

Topic 11, "Reporting Issues Related to Adoption of New Accounting Standards"

Topic 13, "Effects of Subsequent Events on Financial Statements Required in Filings"

SEC Office of Compliance Inspections and Examinations

Examination Priorities for 2016

SEC Regulations

Regulation AB (Asset-Backed Securities):

Item 1101(c), "Definitions; Asset-Backed Security"

Regulation S-K:

Item 507, "Selling Security Holders"

Regulation S-X:

- Rule 4-08(h), "General Notes to Financial Statements: Income Tax Expense"
- Rule 5-02(13), "Commercial and Industrial Companies: Balance Sheets: Assets and Other Debits: Property, Plant and Equipment"

SEC Report

Report on Modernization and Simplification of Regulation S-K

SEC Staff Accounting Bulletin

Topic 11.M, "Disclosure of the Impact That Recently Issued Accounting Standards Will Have on the Financial Statements of the Registrant When Adopted in a Future Period" (SAB 74)

SEC Securities Act of 1933 Rule

Rule 501(a), "Definitions and Terms Used in Regulation D; Accredited Investor""

SEC Securities Exchange Act of 1934 Rules

Section 12g, "Extensions and Temporary Exemptions"

- Rule 12g-1, "Definitions; Exemption From Section 12(g)"
- Rule 12g-4, "Certifications of Termination of Registration Under Section 12(g)"
- Rule 12h-3, "Suspension of Duty to File Reports Under Section 15(d)"

International Standards

IFRS 16, *Leases*

IFRS 15, *Revenue From Contracts With Customers*

IFRS 9, *Financial Instruments*

IAS 32, *Financial Instruments: Presentation*

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

IAS 17, *Leases*

IAS 12, *Income Taxes*

Appendix D — Abbreviations

Abbreviation	Description
ACC	Arizona Corporation Commission
AFS	available for sale
AFUDC	allowance for funds used during construction
AICPA	American Institute of Certified Public Accountants
ALJ	administrative law judge
AOCI	accumulated other comprehensive income
APIC	additional paid-in capital
ARC	asset retirement cost
ARO	asset retirement obligation
ASC	FASB Accounting Standards Codification
ASU	FASB Accounting Standards Update
AT	AICPA Attestation Standard
B&E	blend and extend
Bcf	billion cubic feet
Bcf/d	billion cubic feet per day
BOLI	bank-owned life insurance
BPS	bulk-power system
Btu	British thermal unit
BWR	boiling water reactor
C&DI	SEC Compliance and Disclosure Interpretation
CAIR	Clean Air Interstate Rule
CAISO	California Independent System Operator
CECL	current expected credit loss
CIAC	contribution in aid of construction
CIP	Critical Infrastructure Protection

Abbreviation	Description
CO_2	carbon dioxide
COLI	company-owned life insurance
CPP	Clean Power Plan
CPUC	California Public Utilities Commission
CSAPR	Cross-State Air Pollution Rule
CWIP	construction work in progress
DAA	FERC's Office of Enforcement Division of Audits and Accounting
DOE	U.S. Department of Energy
DOER	U.S. Department of Energy Resources
DPT	delivered price test
DTA	deferred tax asset
DTL	deferred tax liability
e21	Minnesota 21st Century Energy System
EDGAR	SEC's Electronic Data Gathering, Analysis, and Retrieval system
EEI	Edison Electric Institute
EFH	Energy Future Holdings Corp.
EGC	emerging growth company
E-ISAC	NERC's Electricity Information Sharing and Analysis Center
EITF	Emerging Issues Task Force
EPA	Environmental Protection Agency
EPC	engineering, procurement, construction
ERCOT	Electric Reliability Council of Texas
FAQs	frequently asked questions

Abbreviation	Description
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FIFO	first in, first out
FinREC	AICPA's Financial Reporting Executive Committee
GAAP	generally accepted accounting principles
GW	gigawatt
HLBV	hypothetical liquidation at book value
HPUC	Hawaii Public Utilities Commission
HTM	held to maturity
HTML	HyperText Markup Language
IAS	International Accounting Standard
IASB	International Accounting Standards Board
ICFR	internal control over financial reporting
IFRS	International Financial Reporting Standard
IP	intellectual property
IPL	Indianapolis Power & Light Company
IPO	initial public offering
IRC	Internal Revenue Code
IRS	Internal Revenue Service
ISO	Independent System Operator
ISO-NE	ISO New England Inc.
ITC	investment tax credit
kV	kilovolt
kWh	kilowatt hour
LGD	loss given default
LIFO	last in, first out
LLC	limited liability company
LMP	locational marginal pricing
LNG	liquefied natural gas

Abbreviation	Description
M&A	mergers and acquisitions
MACRS	modified accelerated cost recovery system
MATS	Mercury and Air Toxics Standards
MISO	Midcontinent ISO
MMBtu	million Btu
MMBtu/h	million Btu per hour
MPSC	Mississippi Public Service Commission
MTC	minimum tax credit
MW	megawatt
MWh	megawatt hour
NAAQS	National Ambient Air Quality Standards
NAES	Noble Americas Energy Solutions LLC
NERC	North American Electric Reliability Corporation
NETOs	New England Transmission Owners
NM	net metering
NOI	FERC Notice of Inquiry
NOL	net operating loss
NOPR	FERC Notice of Proposed Rulemaking
NO_x	nitrogen oxides
NPNS	normal purchases and normal sales
NPUC	Nevada Public Utility Commission
NRC	Nuclear Regulatory Commission
NRV	net realizable value
NYISO	New York ISO
O&M	operations and maintenance
OATT	Open Access Transmission Tariffs
OCA	SEC's Office of the Chief Accountant
OCI	other comprehensive income
OE	FERC Office of Enforcement
P&U	power and utilities

Abbreviation	Description
PCAOB	Public Company Accounting Oversight Board
PCC	FASB's Private Company Council
PCD asset	purchased financial asset with credit deterioration
PD	probability of default
PG&E	Pacific Gas and Electric Co.
PJM	PJM Interconnection LLC (represents RTO that coordinates the movement of wholesale electricity in all or parts of 13 states and the District of Columbia)
PLR	IRS private letter ruling
PPA	power purchase agreement
PP&E	property, plant, and equipment
PSC	Public Service Commission
PTC	production tax credit
PUCT	Public Utility Commission of Texas
PWR	pressurized water reactor
QAHPI	qualified affordable housing project investment
QPE	qualified progress expenditure
RCC	readily convertible to cash
REC	renewable energy certificate
REV	New York's Reforming the Energy Vision initiative
Rev. Proc.	IRS Revenue Procedure
RIM	retail inventory method

Abbreviation	Description
ROE	return on equity
ROU	right of use
RRWG	revenue recognition working group
RTO	Regional Transmission Organization
SAB	SEC Staff Accounting Bulletin
SAC	subjective acceleration clause
SANS	SysAdmin, Audit, Network, and Security (SANS Institute)
SEC	Securities and Exchange Commission
SIFMA	Securities Industry and Financial Markets Association
SIL	simultaneous transmission import limit
SMR	small modular reactor
SNL	SNL Energy
SO_2	sulfur dioxide
TCC	turbine completion certificate
Tcf	trillion cubic feet
TOU	time of use
TRG	transition resource group
TTHC	Texas Transmission Holdings Corp
TVA	Tennessee Valley Authority
VIE	variable interest entity
XBRL	eXtensible Business Reporting Language

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

Abbreviation	Act
Dodd-Frank Act	Dodd-Frank Wall Street Reform and Consumer Protection Act
Exchange Act	Securities Exchange Act of 1934
FAST Act	Fixing America's Surface Transportation Act
Hart-Scott-Rodino Act	Hart-Scott-Rodino Antitrust Improvements Act of 1976
JOBS Act	Jumpstart Our Business Startups Act
PATH Act	Protecting Americans From Tax Hikes Act of 2015
Recovery Act	American Recovery and Reinvestment Act of 2009
Securities Act	Securities Act of 1933