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Power and Utilities
Accounting, Financial
Reporting, and Tax Update

January 2016

Contents

Foreword	iii
Section 1 — Industry Developments	1
Section 2 — SEC Update	42
Section 3 — Industry Accounting Hot Topics	54
Section 4 — Energy Contracts, Derivative Instruments, and Hedging Activities	83
Section 5 — Accounting Standards Codification Update	89
Section 6 — Implications of the New Revenue Model	124
Section 7 — Overview of the New Leases Model	138
Section 8 — FERC Enforcement Activities	147
Section 9 — Income Tax Update	156
Section 10 — Renewable Energy	164
Appendixes	179
Appendix A — Abbreviations	180
Appendix B — Titles of Standards and Other Literature	183
Appendix C — Deloitte Specialists and Acknowledgments	187
Appendix D — Other Resources and Upcoming Events	189

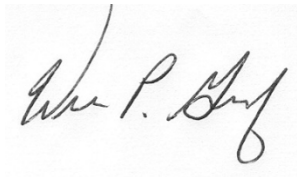
Foreword

January 2016

We are pleased to present our 14th annual Accounting, Financial Reporting, and Tax Update for the power and utilities (P&U) industry. Our industry continues to face changing markets, new legislation, environmental initiatives, regulatory pressures and proposed revisions to the historical compact, and emerging businesses and exponential 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. New to this year's publication are sections that concentrate on accounting and reporting considerations related to (1) the new leases standard, (2) alternative revenue programs, and (3) asset retirement obligations. To highlight an industry sector growth area, we have also included a section on accounting and reporting concerns specific to renewable energy.

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 C](#) for additional information and assistance.

A handwritten signature in black ink, reading "William P. Graf". The signature is written in a cursive style and is centered within a light gray rectangular box.

William P. Graf
U.S. Audit Sector Leader, Power & Utilities
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Section 1 Industry Developments

This section covers some of the developments in the P&U industry that are not addressed in the rest of this publication.

Role of M&A in the P&U Sector

M&A activity in the energy sector continued to heat up in 2015, 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 declining oil prices, sustained low natural gas prices, and potentially rising interest rates. Compounding the market volatility is the movement away from traditional fossil-fuel-fired generation toward cleaner sources and changing energy market dynamics. All of these factors have led to shifting opportunities for energy investments by both public and private entities.

Industry observers predict a flood of generation assets coming up for sale in the PJM Interconnection LLC (PJM) market as declining equity valuations drive publicly traded independent power producers to consider asset sales. 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 problems that have greatly slowed the once rapid pace of deal making in the yieldco sector. Many industry observers also expect the occurrence of more electric/natural gas mergers similar to the following examples of transactions completed and announced in 2015:

- Completed:
 - *June 2015 (announced June 2014)* — Wisconsin Energy Corp. and Integrys Energy Group Inc. (17 percent premium).
 - *October 2015 (announced August 2015)* — NextEra Energy Partners LP and NET Midstream.
 - *December 2015* — Iberdrola S.A. and UIL Holdings Corp. (19 percent premium).
- Announced:
 - *August 2015* — Southern Co. and AGL Resources Inc. (36 percent premium).
 - *September 2015* — Emera Inc. and TECO Energy Inc. (48 percent premium).
 - *October 2015* — Duke Energy Corp. and Piedmont Natural Gas Co. Inc. (40 percent premium).

The current driver of this convergence theme is companies looking to supplement and broaden investment opportunities while remaining in businesses they know and diversifying commodity exposure. Many electric utilities are seeking to grow rate base and earnings while minimizing risk from merchant generation and are willing to have higher debt ratios at the holding company. As a result of this convergence theme, a trend has emerged with an increase in premiums paid, as shown above.

M&A Activity

M&A continued to play an active role in the P&U sector in 2015. Acquiring companies have sought to increase their financial security, reduce their risk profiles and costs, strengthen their balance sheets, diversify their state regulatory risk, and enhance their abilities to employ large capital investment programs. Some companies with regulated operations have sought to grow their rate bases and provide more stable, predictable earnings. Further, over the past few years, companies in the merchant power sector have been expanding their operations through M&A.

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

- *SunEdison Inc. and First Wind Holdings LLC* — On January 29, 2015, SunEdison Inc. and subsidiary TerraForm Power Inc. completed the acquisition of First Wind Holdings LLC. The closing was conditional on First Wind Holdings LLC's acquisition of Emera Inc.'s 49 percent interest in Northeast Wind Partners II LLC, which occurred on January 29, 2015. SunEdison Inc., through its subsidiary TerraForm Power Inc., purchased 500 MW of wind plants, 21 MW of solar plants, and 8 GW of projects under development.
- *Dynegy Inc., EquiPower Resources Corp./Brayton Point Holdings LLC, and certain Midwest generation assets from Duke Energy Corp.* — On April 1, 2015, Dynegy Inc. completed its acquisition of EquiPower Resources Corp. and Brayton Point Holdings LLC from Energy Capital Partners LLC. Dynegy Inc. acquired nine power plants and 50 percent ownership interest in one power plant with capacity to produce approximately 6,300 MW. On April 2, 2015, Dynegy Inc. completed its acquisition of Duke Energy Corp.'s nonregulated Midwest generation assets, which includes ownership interest in 11 power plants with capacity to produce approximately 6,100 MW.
- *Wisconsin Energy Corp. and Integrys Energy Group Inc.* — On June 29, 2015, Wisconsin Energy Corp. completed its acquisition of Integrys Energy Group Inc., which was first announced on June 23, 2014. All necessary approvals were obtained from FERC, the Federal Communications Commission, the Public Service Commission of Wisconsin, the Illinois Commerce Commission, the Michigan Public Service Commission, and the Minnesota Public Utilities Commission. Upon completion of the acquisition, shares of Integrys Energy Group Inc. were delisted and ceased trading on the New York Stock Exchange. The new company provides electricity and natural gas to customers across four states through its principal utilities of Wisconsin Gas LLC (d/b/a We Energies), Wisconsin Electric Power Co. (d/b/a We Energies), Wisconsin Public Service Corp., Peoples Gas Light and Coke Co., North Shore Gas Co., Michigan Gas Utilities Corp., and Minnesota Energy Resources Corp.
- *NextEra Energy Partners LP and NET Midstream* — On October 5, 2015, NextEra Energy Partners LP completed its acquisition of NET Midstream for \$2.1 billion. NET Midstream is a developer, owner, and operator of a portfolio of seven long-term contracted natural gas pipeline assets in Texas. The combined acquisition portfolio includes 3 Bcf/d of ship-or-pay contracts with an average investment-grade counterparty credit and long-term contracted assets with a 16-year average contract life.
- *Iberdrola SA and UIL Holdings Corp.* — On December 16, 2015, Iberdrola SA completed its acquisition of UIL Holdings Corp., which was first announced on February 25, 2015. All necessary approvals were obtained from FERC, the Federal Trade Commission, the Connecticut Public Utilities Regulatory Authority, and the Massachusetts Department of Public Utilities. Review by the New York Public Service Commission (NYPSC) and the Maine Public Utilities Commission was not required. Upon completion of the acquisition, a newly listed U.S. publicly traded company, AVANGRID Inc., was created; the combined company trades on the New York Stock Exchange. Iberdrola SA and UIL Holdings Corp. shareholders own 81.5 percent and 18.5 percent of the combined company, respectively. AVANGRID Inc. has three components: Iberdrola USA Networks, Iberdrola Energy Holdings LLC, and Iberdrola Renewables LLC.



Other significant M&A activity includes the following:

- Exelon Corp. announced on April 30, 2014, that it plans to acquire Pepco Holdings Inc. for \$27.25 per share or approximately \$6.8 billion in cash. The transaction has been approved by FERC and state regulatory bodies in Delaware, Maryland (where the order is under appeal), New Jersey, and Virginia. The Illinois and Pennsylvania commissions were not required to review the transaction since there would be no change of control of the entities operating in those jurisdictions.

However, the last regulatory hurdle is approval from the District of Columbia Public Service Commission (DCPSC). The DCPSC issued an order rejecting the proposed acquisition on August 27, 2015, and Exelon Corp. and Pepco Holdings Inc. jointly filed for DCPSC reconsideration on September 28 and October 2, 2015. Exelon Corp.

subsequently asked the DCPSC to suspend the request for reconsideration to accommodate settlement discussions. On October 6, 2015, Exelon Corp. and Pepco Holdings Inc. reached a settlement with most of the major parties to the proceeding (Office of the Mayor for the District of Columbia, the District's Office of the People's Counsel, the attorney general's office, and other stakeholders). In conjunction with the settlement, they filed a motion requesting that the DCPSC reopen the original merger docket. On October 16, 2015, they submitted a revised schedule requesting all hearings and filings in support of or in opposition to the settlement agreement to be completed before Christmas. Also, on October 16, 2015, the majority of the Council of the District of Columbia signed a letter of support for the merger, which was sent to the DCPSC. On October 28, 2015, the DCPSC agreed to consider the settlement Exelon Corp. reached with various District of Columbia stakeholders and held that Exelon Corp. will not have to refile the merger docket. The DCPSC's ruling means that a decision is likely to be reached in the first quarter 2016. A revised schedule for the merger docket was established by the DCPSC, with briefs filed by December 11, 2015.

- Cleco Corp. announced on October 20, 2014, that it has agreed to be acquired by a group of investors called Cleco Partners, which is led by Macquarie Infrastructure & Real Assets Inc. and British Columbia Investment Management Corp. The deal is valued at approximately \$4.7 billion, including approximately \$1.3 billion of outstanding debt. Cleco Corp. would continue to operate as an independent company led by local management based in Pineville, Louisiana.

FERC approved the proposed transaction on July 17, 2015, and Cleco Corp. shareholders approved the transaction on February 26, 2015. The proceeding for approval from the Louisiana Public Service Commission was initiated on February 10, 2015, and is ongoing. On October 2, 2015, Cleco Corp. and Cleco Partners filed rebuttal testimony with the Louisiana Public Service Commission that outlined several additional commitments to address concerns raised by the Commission staff. Prehearing briefs were due on November 3, 2015, and hearings were set to begin on November 9, 2015. Cleco Corp. anticipates that the transaction will close in the first quarter of 2016.

- NextEra Energy Inc. announced on December 3, 2014, that it has entered into an agreement to acquire Hawaiian Electric Industries Inc. for approximately \$4.3 billion. The potential acquisition has received approval from FERC and Hawaiian Electric shareholders but still needs approval of the Hawaii Public Utilities Commission. Also, the premerger waiting period under the Hart-Scott-Rodino Act expired on September 9, 2015. Hawaiian Electric Industries Inc. must still spin off its banking subsidiary ASB Hawaii.

The discovery phase of the merger approval process with the Hawaii Public Utilities Commission occurred during 2015. After discovery concluded, public sessions were held, followed by evidentiary hearings conducted from November 30 through December 16, 2015. The parties will file closing briefs before the Hawaii Public Utilities Commission issues a decision. The transaction is expected to close in mid-2016.

- Sempra Energy's Mexican subsidiary, Infraestructura Energética Nova SAB de CV (IEnova), announced on July 31, 2015, that it has agreed to purchase Petróleos Mexicanos's (PEMEX's) 50 percent equity interest in the Gasoductos de Chihuahua joint venture for \$1.325 billion plus the assumption of approximately \$170 million in net debt. The joint venture assets include three natural gas pipelines, an ethane pipeline, a liquid petroleum gas pipeline (LPG), and an LPG storage terminal, all of which are under long-term contracts. IEnova and PEMEX will also maintain a joint venture for the Los Ramones Norte pipeline project.

On December 23, 2015, Mexico's Comisión Federal de Competencia Económica (COFECE) ruled against the deal, and before IEnova can purchase PEMEX's interests, PEMEX must hold an open bidding process. IEnova and PEMEX will restructure the transaction to allow for a competitive bidding session. Since IEnova is a partner in the Gasoductos de Chihuahua joint venture, it has the right of first refusal in the bidding. Analysts anticipate that the transaction will be delayed by the bidding process until the first quarter of 2016.

- SunEdison Inc., TerraForm Power Inc.'s yieldco vehicle, announced on July 20, 2015, that it has entered into a \$2.2 billion deal to purchase residential solar system developer Vivint Solar Inc. Once the deal closes, SunEdison Inc. will drop down 523 MW of Vivint Solar Inc.'s rooftop solar portfolio into a TerraForm Power Inc. subsidiary in exchange for \$922 million in cash. SunEdison Inc. plans to fund Vivint Solar Inc.'s acquisition with a new \$500 million secured term loan facility and the \$922 million it will receive from TerraForm Power Inc. On December 8, 2015, SunEdison Inc. announced that (1) it had amended its planned deal of Vivint Solar Inc. to reduce the amount of cash and (2) Blackstone Group LP will provide a \$250 million credit facility to fund growth plans. Under the amended agreement, a TerraForm Power Inc. subsidiary will purchase the rooftop solar portfolio for approximately \$799 million. The transaction is expected to close in the first quarter of 2016.

- Southern Co. announced on August 24, 2015, that it plans to acquire AGL Resources Inc. for \$66 per share or approximately \$7.9 billion in cash plus the assumption of approximately \$4.1 billion in debt. The merger would create the second-largest U.S. utility — 11 regulated electric and natural gas distribution companies, 200,000 miles of electric transmission and distribution lines, over 80,000 miles of gas pipelines, and generating capacity of 46,000 MW. Southern Co. plans to fund the acquisition by using debt and equity issuances, with the equity issuances being spaced out through 2019. Southern Co. and AGL Resources Inc. will continue to operate as separate entities pending regulatory approvals and closing.

The transaction is subject to approval by the Georgia Public Service Commission (filing submitted on December 17, 2015), the Illinois Commerce Commission (filing submitted on October 8, 2015), the New Jersey Board of Public Utilities (filing submitted on October 16, 2015), the Virginia State Corporation Commission (filing submitted on October 26, 2015), the Maryland Public Service Commission (filing submitted on November 3, 2015), and AGL Resources Inc. shareholders (consented to the merger in November 2015). Further, the premerger waiting period under the Hart-Scott-Rodino Act expired on December 7, 2015. The transaction is expected to close in the third quarter of 2016.

- Emera Inc. announced on September 4, 2015, that it plans to acquire TECO Energy Inc. for \$27.55 per share or approximately \$6.5 billion plus the assumption of approximately \$3.9 billion in debt. TECO Energy Inc.'s subsidiaries include Tampa Electric Co. (Florida), Peoples Gas System (Florida), and New Mexico Gas Co. Upon completion of the transaction, Emera Inc.'s asset base will be 56 percent in Florida, 23 percent in Canada, 10 percent in New England, 6 percent in New England, and 5 percent in the Caribbean. TECO Energy Inc. shareholders approved the transaction on December 3, 2015. The transaction is subject to approval by FERC (filing submitted on October 5, 2015), the Florida Public Service Commission, and the New Mexico Public Regulation Commission. Also, the transaction is subject to the expiration or termination of the waiting period under the Hart-Scott-Rodino Act. The transaction is expected to close by mid-2016.



- On September 29, 2015, Hunt Consolidated Inc. and a consortium of investors filed with the Public Utility Commission of Texas (PUCT) their plan to acquire Oncor Electric Delivery Co. LLC and convert it to a real estate investment trust (REIT). The PUCT has 180 days to review and decide on the proposed transaction. Under this plan, Hunt Consolidated Inc. and the consortium of investors have agreed to pay approximately \$12.6 billion to acquire an 80.03 percent stake from Energy Future Holdings Corp. Hunt Consolidated Inc. and the consortium of investors will also assume approximately \$6.3 billion in debt.

Upon completion of the acquisition, Oncor Electric Delivery Co. LLC would be restructured into two companies: Ovation Acquisition I LLC, an asset company that is a subsidiary of a REIT; and Oncor Electric Delivery Co., an operating company. The asset company, which is planning a public equity offering and filed Form S-11 with the SEC on October 30, 2015, would own the physical transmission and distribution assets. The operating company would operate the assets as well as hold the certificates of convenience and necessity and other personal property. A decision by the PUCT is expected by March 31, 2016.

- Duke Energy Corp. announced on October 26, 2015, that it plans to acquire Piedmont Natural Gas Co. Inc. for \$60 per share or approximately \$4.9 billion in cash plus the assumption of approximately \$1.8 billion in debt. Serving more than 1 million gas customers in North Carolina, South Carolina, and Tennessee, with a rate base of approximately \$2.3 billion across those three states, Piedmont Natural Gas Co. Inc. will retain its name and operate as a business unit of Duke Energy Corp. In addition, Duke Energy Corp., Piedmont Natural Gas Co. Inc., and AGL Resources Inc., along with Dominion Resources Inc., are partnering on the development of the 550-mile Atlantic Coast pipeline project. Together, Piedmont Natural Gas Co. Inc. and Duke Energy Corp. have a 50 percent ownership interest in the project.

As disclosed, the acquisition will be financed with a combination of debt, newly issued equity (\$500 million to \$750 million), and other cash sources. The transaction is subject to approval by the North Carolina Utilities Commission and Piedmont Natural Gas Co. Inc.'s shareholders. Also, the transaction is subject to the expiration or termination of the waiting period under the Hart-Scott-Rodino Act. Included in the terms of the acquisition is a reverse termination fee of \$250 million that Duke Energy Corp. would be required to pay Piedmont Natural Gas Co. if it fails to obtain approval from regulators, including the North Carolina Utilities Commission. The reverse termination fee is equivalent to 5.1 percent of the transaction total. The transaction is expected to close by the end of 2016.

During 2015, as in 2014, there was significant activity involving acquisitions of power plants and other assets. In addition, PPL Corp. and Riverstone Holdings combined their independent power generation businesses into a new stand-alone, publicly traded independent power producer, Talen Energy. Upon completion of the formation of Talen Energy, 65 percent of the new company was owned by PPL Corp. shareholders and 35 percent of it was owned by affiliates of Riverstone Holdings. Talen Energy began trading on June 1, 2015.

The table below lists some of the transactions that occurred in 2015 (dollar amounts in millions):

Date	Buyer	Seller	Base Value	Assets
11/27/2015	Energy Future Holdings Corp.	NextEra Energy, Inc.	\$1,310	2 gas-fired plants
10/8/2015	Brookfield Asset Management Inc.	Talen Energy Corp./Holtwood & Lake Wallenpaupack Ops	\$860	2 hydroelectric plants
10/8/2015	TransCanada Corp.	Talen Energy Corp./Ironwood Plant Ops	\$654	1 gas-fired plant
10/1/2015	Platinum Equity LLC	AEP Resources Inc.	\$550	River barge operations
9/21/2015	AltaGas Ltd.	GWF Energy LLC	\$642	3 gas-fired plants
7/15/2015	ArcLight Capital Holdings LLC	Infigen Energy Ltd.	\$273	U.S. wind business
7/20/2015	Talen Energy Corp.	MACH Gen LLC	\$1,175	Portfolio of gas-fired plants
7/6/2015	TerraForm Power Inc.	Invenergy Wind LLC	\$2,000	Portfolio of wind projects
4/1/2015	TerraForm Power Inc.	Atlantic Power Transmission Inc.	\$350	Interests in portfolio of wind projects
3/6/2015	NextEra Energy Inc.	CBAS Power Inc.	\$521	1 coal plant

Ratemaking

Rate-Case Activity

The number of retail rate cases in the United States has approximated 100 in each of the last four calendar years. There were 99 electric and gas rate cases resolved in both 2014 and 2013, 111 in 2012, and 87 in 2011. Approximately 25 electric and gas rate cases were decided in the first nine months of 2015, and roughly 30 electric and gas rate cases were decided in the fourth quarter of 2015; this volume was significantly 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.

For January through September 2015, the average return-on-equity (ROE) percentages for both electric and gas utilities, as set by regulators, were on par with the average ROE percentages in 2014 when adjusted for rate cases for electric utilities in Virginia that incorporated ROE premiums as allowed by Virginia statutes for certain generation projects. The average ROE percentage for electric utilities in the first nine months of 2015 was approximately 9.55 percent (based on 18 cases), and the average ROE percentage in 2014 was approximately 9.76 percent (based on 38 cases). Further, the average ROE percentage set by regulators for gas utilities in the first nine months of 2015 was approximately 9.49 percent (based on seven cases), and the average ROE in 2014 was approximately 9.78 percent (based on 26 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.

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 Phase II, which will concentrate on defining the details of Phase I recommendations as well as addressing unanswered questions raised during Phase I. Additional participants will be brought on to assist with Phase II.

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.

Future of Coal-Fired Generating Units

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

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 evidenced by the fact that certain plants are slated to be retired over the next several years. Recent reports have indicated that companies have formalized plans to permanently shut down approximately 29,000 MW of capacity from 2016 through the end of 2026.¹ In addition, some companies are planning to convert existing coal-fired generating units to burn other fuels such as natural gas or biomass. Recent reports have pointed out that over 7,000 MW has potentially been identified for conversion between 2016 and 2021.² As the cost of replacement power and projected energy margins decrease, decreases in spot and forward natural gas prices may have a greater impact on the decision of whether to retrofit coal-fired generating units rather than retire them.

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

¹ Source: http://www.sourcewatch.org/index.php/Coal_plant_retirements.

² See footnote 1.

Clean Air Interstate Rule

In April 2005, the EPA issued the CAIR to regulate emissions of SO₂ 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 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 would have set limits on emissions from power plants in 28 eastern states via a new cap-and-trade program. While a federal appeals court vacated certain aspects of the CSAPR in August 2012, the U.S. Supreme Court ultimately ruled 6–2 to uphold 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. 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. On June 1, 2015, the EPA issued a notice of data availability that details the first round of allowance allocations for new units.

Thinking It Through

The U.S. 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. Ultimately, on July 28, 2015, while offering its opinion on the remaining issues, the appeals court upheld the rule. Consequently, the CSAPR remains in place.

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 SO₂ emissions from power plants by 41 percent. Unlike the CSAPR or CAIR, the MATS rule is not a cap-and-trade program; no emissions allowances are involved. If a specific plant emits more mercury or other toxics than are permitted, that plant is not allowed to operate. Under the MATS rule, reductions were to be achieved starting in the first quarter of 2015. However, on June 29, 2015, 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 (the "D.C. Circuit"), which is now assessing the Supreme Court decision to determine its next steps.

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 (EGU) plants. Under the CPP, by the year 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 SO₂ levels, by about 25 percent.

The CPP is not a new set of rules or regulations but an initiative that would allow states to develop their own implementation plan to meet certain CO₂ emissions requirements. Under the CPP, states would still need to comply with existing federal and state emissions regulations such as the CAIR, the MATS, the NAAQS, and regional haze rules. However, these regulations would be supplemented by individualized state-developed strategies that would further reduce power plant emissions to meet a state's CPP-defined goal.

The final rule provides 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. The final rule became effective on December 22, 2015.

Thinking It Through

In response to the CPP, the utility industry and nearly two dozen states filed lawsuits regarding the CPP. On June 9, 2015, however, the U.S. Supreme Court dismissed the cases brought before it, holding that the challenge was premature since a final rule had yet to be issued. After the EPA's final rule was issued in August 2015, a number of stakeholders and several states filed a petition with the U.S. Court of Appeals requesting an emergency stay of the CPP on the grounds that (1) power plants are already regulated under other EPA rules and should therefore not be subject to double regulations of pollutants and (2) the EPA rules should be limited to emissions at the smokestack level and should not extend past fence lines. At this point, these cases are ongoing. In addition, on October 23, 2015, an alliance of 26 states and a coal mining company filed suit in the D.C. Circuit on the grounds that the EPA has overstepped the authority granted by Congress by imposing strict guidelines that force a reduction in fossil fuel use by power plants. There is no timeline for when the appeals court will consider the merits of the case.

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

On August 3, 2015, the EPA issued its final rule establishing CO₂ 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 CO₂ per MWh.
- *Reconstructed and modified fossil-fuel-fired steam-generating units* — Emissions would be limited to:
 - 1,800 pounds of CO₂ per MWh for sources with heat input greater than 2,000 MMBtu/h.
 - 2,000 pounds of CO₂ 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 CO₂ per MWh (or 1,030 pounds of CO₂ 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. Given the onerous emissions standards introduced by this rule, it is unlikely that any new coal-fired generating units will be constructed in the United States. The final rule became effective on October 23, 2015.

Master Limited Partnerships, Yieldcos, and Real Estate Investment Trusts

Master Limited Partnerships (MLPs)

An MLP that satisfies specific criteria in the Internal Revenue Code is a publicly traded entity that is (1) subject to the same accounting, reporting, and regulatory requirements as a publicly traded corporation but (2) not subject to entity-level federal income tax. Instead, the obligation to pay income taxes flows through to the unit holders. MLP partners are either (1) limited partners (LPs), which provide the MLP with capital and periodically receive income distributions from it, or (2) general partners (GPs), which manage the MLP and are compensated for its performance. For a structure to qualify for taxation as an MLP, at least 90 percent of the gross income of the partnership must be derived from real estate, natural resources, or commodities.

In 2013, Congress introduced two bills related to MLPs, which would amend the Internal Revenue Code to include clean energy technologies within the MLP structure. Specific energy technologies that would qualify include wind, closed- and open-loop biomass, geothermal, solar, municipal solid waste, hydropower, marine and hydrokinetic, fuel cells, and combined heat and power. Other types of technologies that would qualify include various types of transportation fuels, such as cellulosic, ethanol, biodiesel, and algae-based fuels; energy-efficient buildings; electricity storage; carbon capture and storage; renewable chemicals; and waste-heat-to-power technologies.



On June 24, 2015, Congress reintroduced bills similar to the 2013 bills, which were not enacted. The proposed legislation includes some revisions, such as an expansion to cover renewable energy projects that are leased by the MLP to its customers. If enacted, the 2015 bills would not adversely affect any current MLPs. All projects currently eligible for inclusion in an MLP would continue to qualify exactly as under existing law.

If enacted, the bills could lower the tax burden and increase the liquidity of clean energy investments, thereby lowering financing costs and removing constraints on the development and deployment of renewable energy. However, it is uncertain whether the proposed legislation will ultimately be enacted. In addition, there is uncertainty regarding the value of a tax structure that is untested in the renewable energy industry. For more information on MLPs, see [Master Limited Partnerships and Yieldcos](#) in Section 3.

Yieldcos

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

Yieldcos are not as tax-efficient as MLPs because they are taxed as corporations and are therefore subject to double taxation. However, the underlying assets of a yieldco generate tax credits (e.g., PTCs or ITCs) as well as accelerated depreciation deductions (including bonus depreciation) for tax purposes. As a result of these entity-level tax benefits, there could be minimal tax liability at the yieldco level during the first several years of operations and during periods of capital investments.

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

P&U areas, such as transmission and distribution. For more information on yieldcos, see [Master Limited Partnerships and Yieldcos](#) in Section 3.

Real Estate Investment Trusts

A REIT is a taxable corporation that meets certain criteria and elects special tax treatment. The requirements for REIT status include, but are not limited to, (1) ownership by 100 or more persons, (2) real estate and/or other specified assets comprising 75 percent or more of the corporation's gross assets at the end of each quarter, and (3) rents from real property and/or other specified sources of income comprising 75 percent or more of the corporation's gross income. In addition, a REIT must distribute at least 90 percent of its taxable income (excluding capital gains). A REIT is subject to corporate income tax on its undistributed taxable income.

REITs, like MLPs and yieldcos, are an important source of funding for infrastructure in the United States. Traditionally, REITs hold commercial real estate properties. More recently, however, investors have explored the use of REIT structures for other types of real estate, including casino properties and public utility assets such as transmission property.

In a typical REIT structure, the entity qualifying as a REIT owns the real property assets and leases those assets to one or more entities that manage them. REITs pay little or no corporate income tax on their earnings as long as they earn most of their profits from rent on qualifying real estate assets and distribute at least 90 percent of those profits to shareholders in the form of dividends. The ability to avoid corporate-level taxes while providing a predictable earnings stream over a period makes REITs attractive to investors and allows infrastructure assets held by a REIT to command a premium over comparable assets in a less advantageous structure.

There are several hurdles to using a REIT structure to own public utility assets, not the least of which are regulatory and tax hurdles. A REIT structure must be approved by state and/or federal regulators. Regulators may have concerns about the legal separation of the public utility assets from the entity responsible for operating the public utility assets. In addition, while FERC has historically permitted an income tax expense in establishing rates for wholesale customers of entities such as partnerships that pay no income taxes, there may be uncertainty about how a state regulator will consider income taxes in rate setting. Significant tax hurdles also exist, including demonstrating to the IRS that the entity owning the real property qualifies as a REIT. When the public utility assets are currently owned by a utility, there is also the issue of how to extract those assets without incurring a prohibitive up-front tax cost. Further, the compliance costs associated with a REIT can be greater than those associated with a corporation.

On May 9, 2014, the U.S. Department of the Treasury issued [proposed regulations](#) that would allow certain solar developments to qualify for inclusion in REITs. The proposed regulations could introduce new capital to the solar industry because solar facilities would be considered "real property" in certain situations.

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

Integrated Marketplaces

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

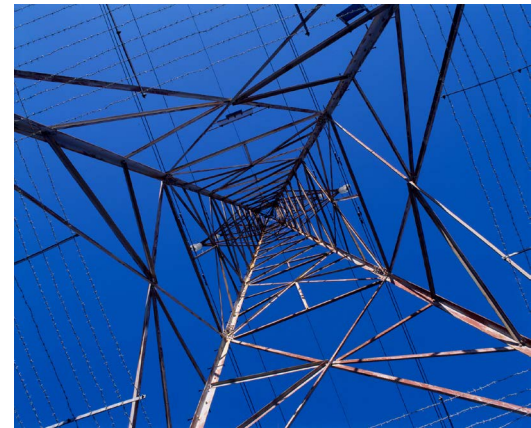
- *Southwest Power Pool Inc. (SPP)* — On March 1, 2014, SPP, a regional transmission organization (RTO), implemented its integrated marketplace after FERC approval of its certificate of readiness on February 26, 2014. The integrated marketplace replaced SPP's energy imbalance service market. SPP's energy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

SPP added three utilities to its membership on October 1, 2015: Western Area Power Administration's Upper Great Plains Region, Basin Electric Power Cooperative, and Heartland Consumers Power District. The addition of Western Area Power Administration's Upper Great Plains Region marks the first time a federal government agency has joined an RTO. The SPP RTO region now covers 575,000 square miles of service territory, over 800 generating plants, approximately 5,000 substations, and 56,000 miles of high-voltage transmission lines in Arkansas, Iowa, Louisiana, Minnesota, Mississippi, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wyoming.

- *California Independent System Operator (CAISO) and PacifiCorp* — On October 1, 2014, CAISO and PacifiCorp launched the Western U.S. Energy Imbalance Market (EIM), which became fully operational and financially binding on November 1, 2014. The EIM currently involves balancing authority areas in seven western states (part of California, Idaho, Nevada, Oregon, Utah, Washington, and Wyoming) and uses an automated system that balances electricity supply and demand every 15 minutes and dispatches the resources that cost the least every 5 minutes. The market is designed to identify the most efficient resources over a wider geographical area, reducing electricity costs while enhancing reliability by employing a larger pool of resources to manage the grid. Each balancing authority area is responsible for meeting its own operating reserve and planning reserve requirements.

During 2015, there was significant activity related to utilities' joining, or filing with the FERC to join, the EIM. NV Energy Inc. was expected to join on November 1, 2015, after receiving approval from FERC in May 2015 for its open-access transmission tariff changes, but its inclusion was delayed pending some key FERC orders, which were approved in November. NV Energy Inc.'s membership in the EIM became effective on December 1, 2015. Puget Sound Energy Inc. will join in October 2016, having received approval from FERC in May 2015 for its implementation agreement with CAISO. Arizona Public Service Co. signed an implementation agreement with CAISO to join the EIM in October 2016. CAISO will need to file the implementation agreement with FERC to obtain approval, and Arizona Public Service Co. will need to file changes to the open-access transmission tariff with FERC. On September 18, 2015, Portland General Electric Co. announced that it was investigating whether to join the EIM instead of participating in the Northwest Power Pool (NWPP). Portland General Electric Co. entered into an implementation agreement with CAISO on November 20, 2015, and will join the EIM on October 1, 2017. On September 24, 2015, Idaho Power Co. followed Portland General Electric Co. in deciding that it will pursue participation in the EIM instead of the NWPP, with a final decision on participation expected in the first quarter of 2016. On December 4, 2015, the Los Angeles Department of Water announced that it is evaluating participation in the EIM.

On October 7, 2015, California Governor Jerry Brown signed into law Senate Bill 350, the Clean Energy and Pollution Reduction Act of 2015 (SB 350), which sets a renewable portfolio standard (RPS) of 50 percent by 2030, a jump from the state's current RPS of 33 percent by 2020. Included in SB 350 is language designed to help reach this new RPS, namely by providing "for the transformation of the [ISO] into a regional organization to promote



the development of regional electricity transmission markets in the western states and to improve the access of consumers served by the [ISO] to those markets.”

CAISO under SB 350 is charged with coming up with a new governance proposal for the RTO, with any bylaw changes submitted to the legislature no later than December 31, 2017. This new governance design would replace CAISO’s existing bylaws. One year after the seating of the new board and every two years thereafter, the bill requires that the new RTO entity prepare “a report to the states within the areas it serves documenting its furtherance of applicable state and federal laws and regulations affecting the electric industry.” Actual RTO formation is tentative since PacifiCorp has not made a formal decision to join as a participating transmission owner (PTO).

On October 13, 2015, CAISO and PacifiCorp released a study projecting that integration of their electric grids to create a regional power marketplace could result in overall customer benefits of \$3.4 billion to \$9.1 billion over 20 years and could help states meet their environmental goals. The customer benefits would be realized through better grid management and efficiencies gained from planning for the resource needs of a single system rather than multiple systems. Also, it is likely that an RTO would reduce greenhouse gas emissions through coordinated planning as well as reduce curtailment of renewable energy sources. CAISO and PacifiCorp extended their Memorandum of Understanding (MoU) executed in April 2015 to further explore costs and other requirements needed to achieve the benefits of integration outlined in the study, as well as to develop a transition agreement to outline the terms and conditions for the potential integration of PacifiCorp into a regional market.

During CAISO’s 2015 Stakeholder Symposium (October 22–23, 2015), utility regulators from Arizona, California, Montana, Oregon, and Washington expressed an openness to working together to improve coordination of the regional grid. The regulators acknowledged that although politics can create challenges to regional cooperation, there are common issues and interests to support the management of renewable energy supplies and CO₂ targets under the CPP. A key issue for the states as discussion of an RTO moves forward is how to work out different perceptions of how to value energy and its no-emission attributes.

On December 1, 2015, CAISO launched a new regional resource adequacy (RA) initiative tied to potentially becoming a regional grid operator in the West. The initiative aims to “evaluate resource adequacy tariff provisions appropriate for use in a regional ISO balancing authority area that encompasses multiple states.” On December 9, 2015, CAISO issued a paper titled *Regional Resource Adequacy*, which discusses CAISO’s existing RA construct and the tariff elements that would need to be revised since the RA program in California does not have similar counterparts in other western states. The revisions would make the tariff elements more generic to apply on a regional basis. Comments on the paper were due by January 7, 2016.

- *NWPP*— Launched in March 2012 and led by the Market Assessment and Coordination Committee, which comprises 16 balancing authorities and three scheduling entities, the NWPP proposes a centrally cleared energy dispatch (CCED) market. In October 2015, the NWPP lost another member that had been participating in talks about creating the regional energy dispatch market. This latest loss could signal the likely final days of the effort to form the NWPP. There has been a significant exodus of utilities to the EIM in recent months, including Puget Sound Energy Inc., Portland General Electric Co., and Idaho Power Co. In another blow to the NWPP, the Balancing Authority of Northern California stated on October 5, 2015, that it has decided not to participate in that organization. On December 9, 2015, members of the NWPP requested that FERC hold in abeyance their September petition for a declaratory order on the NWPP’s proposed CCED market.

Liquefied Natural Gas

According to the U.S. Energy Information Administration’s (EIA’s) *Annual Energy Outlook 2015* (AEO2015), the United States is expected to become a net exporter of natural gas by 2017. After 2017, the natural gas market will be driven by the availability of natural gas resources and world energy prices. Greater availability of domestic natural gas or increases in world energy prices would widen the gap between the cost of U.S. natural gas and world prices, thereby encouraging U.S. exports of liquefied natural gas (LNG). Most of the growth in U.S. net exports of natural gas is projected to occur before 2030 as increased supply of domestic natural gas satisfies new demand both internationally (with the development of LNG export capacity and growing demand for pipeline exports) and domestically. Increased shale gas production accounts for three-quarters of the increase in total dry gas production.

During 2015, there was price pressure in the global markets that is set to continue in 2016 because of (1) high inventories across the Northern Hemisphere after a mild winter, (2) slowing cyclical demand in emerging markets, and (3) the restarting of nuclear facilities in South Korea and Japan. World LNG estimated October 2015 landed prices from Waterborne Energy Inc. for Asia were \$7.25 per MMBtu in Japan and South Korea and \$7.10 per MMBtu in China. These figures are down from estimated June 2015 prices of \$7.80 per MMBtu in Japan and South Korea and \$7.65 per MMBtu in China and remain at a significant discount of more than 60 percent compared with the record peak price of above \$20 per MMBtu in February 2014. Elevated Asian LNG prices in 2014 were a result of rapid growth in Chinese demand and the impact of the Fukushima Dai-ichi nuclear shutdown in Japan.

Construction and Operation of LNG Export Facilities

FERC must approve the construction and operation of LNG export facilities, while the U.S. Department of Energy (DOE) must authorize exports to nations that do not adhere to free trade agreements, such as Japan, India, and the United Kingdom.

As of December 2, 2015, the DOE had received 52 applications for authorization of exports to nations that operate under free trade agreements and had approved 50 of them. In addition, the DOE had received 46 applications for authorization of exports to nations that do not operate under free trade agreements and had issued final approval for 13 and conditionally approved 3:

Applications That Have Received Final Approval

Four approvals for Sabine Pass Liquefaction LLC (a subsidiary of Cheniere Energy Inc.) — FERC approval granted on April 16, 2012; the company began constructing four liquefaction trains in August 2012, with the first train expected to produce LNG by late 2015; the other three trains are expected to become operational from 2016 to 2017.

On June 30, 2015, Cheniere Energy Partners LP announced its final investment decision for train 5 and has issued a notice to begin construction. Train 5 is expected to become operational in 2018. The project will have up to six liquefaction trains.

Cameron LNG LLC — FERC approval granted on June 19, 2014. In late 2014, the company began constructing three liquefaction trains, which are expected to become operational in 2018.

On September 28, 2015, Cameron LNG LLC submitted its formal application to FERC for an expansion project at its LNG export terminal already under construction. It has requested that FERC approve its application for the two-train, 1.41-Bcf/d expansion of its original three-train project by May 2016 so that construction can start in June 2016 and the expansion project can become operational by the end of 2019.

Two approvals for Freeport LNG Expansion LP and FLNG Liquefaction LLC (subsidiaries of Freeport LNG Development LP) — FERC approval granted on July 30, 2014, and FERC approval pending, respectively. Construction of three liquefaction trains began in 2015, with the first train expected to produce LNG by the third quarter of 2018. Other trains are expected to become operational in 2019.

Dominion Cove Point LNG LP (a subsidiary of Dominion Resources Inc.) — FERC approval granted on September 29, 2014. In late 2014, the company began constructing its LNG terminal, which is expected to begin operations in late 2017.

Cheniere Marketing LLC and Corpus Christi Liquefaction LLC (subsidiaries of Cheniere Energy Inc.) — FERC approval granted on December 30, 2014. Construction of two liquefaction trains began in 2015; the first train is expected to start operations in 2018, and the second train is expected to do so approximately six to nine months thereafter.

On June 1, 2014, Corpus Christi Liquefaction LLC unveiled plans for a two-train expansion and asked FERC to start the pre-filing review process. It expects to file a formal application for the project by January 2016 and to start construction of the trains and related gas pipeline in May 2017 and March 2018, respectively. The project is projected to become operational in the first quarter of 2021.

Carib Energy (USA) LLC (a subsidiary of Crawley Maritime Corp.) — No FERC approval is needed because the project does not involve construction of an LNG export terminal.

American LNG Marketing LLC — No FERC approval is needed because the project does not involve construction of an LNG export terminal.

Floridian Natural Gas Storage Co. — No FERC approval is needed because the project does not involve construction of an LNG export terminal.

Air Flow North America Corp. — No FERC approval is needed because the project does not involve construction of an LNG export terminal.

Applications That Have Received Conditional Approval

Lake Charles Exports LLC — FERC approval is pending.

Jordan Cove Energy Project LP (a subsidiary of Veresen Inc.) — FERC approval is pending and is expected by mid-2016.

LNG Development Company LLC (d/b/a Oregon LNG) — FERC approval is pending.

As of October 20, 2015, there was a total of 27 LNG export projects for which formal applications were pending FERC approval. Four of these projects are located in Canada, two in the Pacific Northwest, one in the Northeast, and 20 in the Southeast.

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

Cybersecurity

In 2011, the U.S. Government Accountability Office (GAO) issued a report outlining some of the challenges facing the electric power industry as it becomes more reliant on computerized technologies. While many of the report's recommendations have since been implemented, an important one has not — namely, the recommendation that FERC coordinate with other regulators to identify strategies for monitoring compliance with voluntary cybersecurity standards in the industry. Because this recommendation has not been implemented, FERC does not know whether such standards have been adopted or whether they are effective.

The North American Electric Reliability Corp. (NERC) has revamped its critical infrastructure protection standards, the National Institute of Standards and Technology (NIST) has updated its smart-grid cybersecurity standards, and the Department of Homeland Security (DHS) has issued recommended practices to reduce risks to industrial control systems in critical infrastructure sectors, including the energy sector. The primary activities performed by FERC is establishment of an office of energy infrastructure security and holding a technical conference in 2011 that solicited stakeholder input on addressing cybersecurity vulnerabilities, among other things. To date, FERC has declined to adopt an initial set of smart-grid interoperability standards developed by NIST; therefore, those standards have remained voluntary.

Because of the increasing reliance on computerized technologies, the electric utility industry is becoming more susceptible to an array of cyber-based threats. NERC and FERC are critical to approving and disseminating cybersecurity guidance and standards. NIST, DHS, and the DOE also play roles in providing guidance and other forms of support for protecting the sector against cyber threats. As a result of FERC's failure to monitor the implementation of voluntary cybersecurity standards, FERC and other federal agencies do not know the extent to which the standards have been adopted by the industry or whether they are effective.



On October 22, 2015, the U.S. Senate agreed to start voting on a cybersecurity information sharing bill. S.754, the proposed Cybersecurity Information Sharing Act of 2015 (CISA), would limit liability for companies that share cyberthreat and cyberattack information with the federal government and other entities. CISA would also require federal agencies to scrub personal information from the cyberthreat data they share with the private sector, require the DHS to report to Congress on how cyber intrusions are reported, require federal agencies to develop a mitigation strategy for protecting critical infrastructure, and provide for a government assessment of whether companies should be required to report cyberincidents.

The Senate passed CISA on October 27, 2015. A House and Senate conference committee will now have to resolve the differences between CISA and two companion bills passed by the House of Representatives in April 2015 — H.R. 1560, the proposed Protecting Cyber Networks Act; and H.R. 1731, the proposed National Cybersecurity Protection Advancement Act.

Further, in July 2015, FERC published a Notice of Proposed Rulemaking (NOPR) to address various aspects of CIP Version 5 revisions, most likely in response to widespread advanced persistent threat campaigns against utilities and utility-related industrial commercial systems vendors across multiple years (i.e., malicious software from the “Energetic Bear” hacking group). Underlying the NOPR was an expression of concern about the impact of the supply chain access vector on industrial control system hardware, software, and services associated with bulk electric system operations and critical infrastructure reliability. Key to enabling the effort, FERC identified the newly released publication from NIST on supply chain risk management (NIST SP-800-161) as a potential solution for regulation. It is important to note that nuclear-critical cyber regulations such as NEI-08-09 already require treatment of the supply chain vector and that other nations have proceeded to nationalize their supply chains related to nuclear facilities.

NIST

Executive Order 13636 was issued in 2013 with the goal of improving critical infrastructure cybersecurity. This order directed collaboration of specific government entities to reduce risk across the national critical infrastructure. One key directive was for NIST to provide a framework that helps critical infrastructure owners prioritize and protect the infrastructure. NIST released the first version of its [critical infrastructure cybersecurity framework](#) in February 2014. The framework outlines what NIST believes is a strategic, cost-effective approach to managing cybersecurity-related risks. According to NIST, the framework “focuses on using business drivers to guide cybersecurity activities and considering cybersecurity risks as part of [an] organization’s risk management processes.” The framework is intended for use by all companies, regardless of their size or complexity, and contains risk management principles (and best practices) that would allow companies to improve “the security and resilience of critical infrastructure.” However, NIST cautions companies that the framework is not a “one-size-fits-all” approach for dealing with cybersecurity risks.

Physical Security

Project 2014-04, *Physical Security*

In April 2013, Pacific Gas and Electric Company (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. This action happened at a time when the grid was not under stress; however, 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 (ERO), to submit for approval one or more 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). The 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, and is currently awaiting FERC approval.

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 an initial step, this group created a stand-alone company, Grid Assurance LLC, to handle virtually all of their spare transformer equipment needs. Together, the companies have footprints in 32 states and serve about 35 million customers.

Participation in Grid Assurance LLC would be open to all energy entities on a subscription basis. In accordance with a subscriber agreement, Grid Assurance LLC would (1) maintain an inventory of critical spare transformers, circuit breakers, and related transmission equipment; (2) provide secure domestic warehousing of the inventory of spares in strategic locations; and (3) release 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.

Once the proposal was made, certain parties raised concerns about whether Grid Assurance LLC would be an equipment manufacturer. The proposal was subsequently clarified to state that Grid Assurance LLC would purchase spare equipment from manufacturers for resale to subscribers in emergency situations. If FERC were to approve the proposal, it would take 18 months to two years to put the necessary inventory in place.

On August 7, 2015, FERC approved only part of the proposal since a rate filing under Section 205 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.

GridEx III

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.

The exercise is the third of its kind and has grown in popularity to include many organizations and registered participants. The E-ISAC holds the GridEx tabletop exercises every two years, each one with new and more complex challenges. NERC is expected to issue a public report in the first quarter of 2016 outlining what lessons can be learned from the exercise.

Market Prices

On its Web site, the EIA points out that “the United States has many regional wholesale electricity markets” and that “[w]holesale electricity prices are closely tied to wholesale natural gas prices in all but the center of the country.” The correlation between natural gas and electricity prices is strong enough that the prices usually rise and fall in tandem. With respect to wholesale natural gas prices, the main pricing point in the United States is Henry Hub in Louisiana.

Below is a table summarizing current and historical average wholesale electricity prices (on-peak and off-peak) for CAISO, the Electric Reliability Council of Texas (ERCOT), ISO New England Inc. (ISO-NE), MISO, New York ISO (NYISO), PJM, and SPP. Also included is a summary of current and historical average wholesale natural gas prices for Henry Hub. The average wholesale electricity prices and wholesale natural gas prices are calculated by using SNL ISO day-ahead on-peak/off-peak prices and SNL day-ahead natural gas prices, respectively.

SNL ISO Day-Ahead — On Peak Prices							
Date	CAISO Average	ERCOT Average	ISO-NE Average	MISO Average	NYISO Average	PJM Average	SPP Average
First nine months of 2015	34.54	34.60	54.57	32.62	47.99	41.87	27.83
2014	50.38	47.15	76.17	46.52	67.64	57.88	38.82
2013	44.89	38.16	64.72	38.36	54.36	42.20	N/A
2012	32.55	35.48	41.88	33.50	42.15	37.19	N/A
2011	36.21	61.48	52.84	39.24	52.60	47.50	N/A
2010	39.51	N/A	56.06	40.18	55.12	48.29	N/A
2009	37.43	N/A	46.27	34.15	46.35	40.21	N/A

SNL ISO Day-Ahead — Off Peak Prices							
Date	CAISO Average	ERCOT Average	ISO-NE Average	MISO Average	NYISO Average	PJM Average	SPP Average
First nine months of 2015	28.97	22.26	39.53	24.33	31.29	28.30	20.75
2014	40.57	32.02	53.78	33.41	44.50	37.07	26.79
2013	36.30	28.25	48.76	30.37	38.99	30.47	N/A
2012	23.59	22.13	31.39	23.54	30.54	27.03	N/A
2011	22.41	31.06	40.67	26.15	39.95	33.35	N/A
2010	30.00	N/A	42.29	25.82	41.38	34.32	N/A
2009	26.91	N/A	37.12	20.93	34.90	29.64	N/A

SNL Day-Ahead Natural Gas Prices	
Date	Henry Hub Average
First nine months of 2015	2.80
2014	4.37
2013	3.73
2012	2.76
2011	4.00
2010	4.37
2009	3.94

Energy Policy

In 2015, U.S. congressional committees reported significant bills on energy policy:

- *Energy Policy Modernization Act of 2015 (S. 2012)* — Reported by the Senate Energy and Natural Resources Committee to the Senate on July 22, 2015, for further consideration.
- *American Energy Innovation Act of 2015 (S. 2089)* — Reported by the Senate Energy and Natural Resources Committee, the Senate Finance Committee, and the Senate Environment and Public Works Committee to the Senate on September 22, 2015, for further consideration.
- *North American Energy Security and Infrastructure Act of 2015 (H.R. 8)* — Reported by the House Energy and Commerce Committee to the House of Representatives on September 30, 2015, for further consideration.

Key provisions of these bills are summarized below.

Energy Policy Modernization Act of 2015 (Proposed)

Title I, “Efficiency”

Title I of the proposed Energy Policy Modernization Act of 2015 includes the following provisions:

- *“Buildings”* — Matters addressed in this subtitle include:
 - Building codes.
 - Energy and water conservation improvements for low-income multifamily residential units and federal buildings.
 - Retrofitting schools and nonprofit buildings with energy efficiency improvements.
 - Extending the maximum contract period of utility energy service contracts from 10 years to 25 years.
 - Energy-efficient data centers.
 - The Weatherization Assistance Program.
 - Reauthorization of the State Energy Program.
- *“Appliances”* — Matters covered include:
 - Rebate programs.
 - Standards for certain furnaces.
 - Certification requirements for Energy Star program partners.
- *“Manufacturing”* — Includes provisions related to:
 - Manufacturing energy efficiency.
 - Smart manufacturing technologies.

Title II, “Infrastructure”

Title II of the proposed Energy Policy Modernization Act of 2015 includes the following provisions:

- *“Cybersecurity”* — This subtitle would:
 - Give the U.S. Secretary of Energy emergency authority to protect the BPS from cybersecurity threats.
 - Codify the designation of the DOE as the sector-specific agency for cybersecurity for the energy sector and specify the DOE’s duties related to that role.

- *“Strategic Petroleum Reserve” (SPR)* — This subtitle would require the DOE to:
 - Give Congress prior notice of any SPR test sale (except for emergency drawdowns).
 - Submit a report after any SPR sale.
- *“Trade”* — This set of provisions would require:
 - The Secretary of Energy to issue a final decision approving or disapproving any application to export natural gas to countries that do not have free trade agreements with the United States no later than 45 days after FERC or the Maritime Administration has concluded the review required by the National Environmental Policy Act (NEPA).
 - The EIA to collaborate with Mexican and Canadian officials to improve the collection of cross-border energy data.
- *“Electricity and Energy Storage”* — This set of provisions would:
 - Require the Secretary of Energy to conduct a research, development, and demonstration program for electric grid storage.
 - Promote the development of (1) hybrid microgrid systems for isolated communities and (2) microgrid systems to increase the resilience of critical infrastructure.
 - Help facilitate state and regional distribution planning.
 - Help improve the permitting process for electric transmission infrastructure.
 - Require a transmission organization to submit a report to FERC within six months after the date of enactment that identifies (1) barriers to the transmission organization’s deployment of distributed energy systems and microgrid systems and (2) potential changes to the operational requirements for, or the charges associated with, the interconnection of these resources to the transmission organization.

Title III, “Supply”

Title III of the proposed Energy Policy Modernization Act of 2015 includes the following provisions:

- *“Renewables”* — This set of provisions includes measures related to:
 - *“Hydroelectric”* — Designates FERC as the lead agency to set a binding schedule and coordinate all needed federal authorizations to address hydropower permitting backlogs, hydroelectric production incentives, and efficiency improvements.
 - *“Geothermal”* — Addresses matters related to (1) national goals for production and site identification, (2) facilitation of coproduction of geothermal energy on oil and gas leases, and (3) large-scale geothermal energy.
 - *“Marine Hydrokinetic”* — Covers items such as (1) the definition of marine and hydrokinetic renewable energy and (2) participation in demonstration projects.
- *“Oil and Gas”* — Includes amendments to the Methane Hydrate Research and Development Act of 2000.
- *“Critical Minerals”* — Matters covered include (1) critical mineral designations, (2) permitting, and establishment of forecasting capabilities for critical mineral reliance, production, price, recycling, and related factors.
- *“Coal”* — Would amend Section 961(a) of the Energy Policy Act of 2005 to include improvement of conversion, use, and storage of CO₂ produced from fossil fuels as an objective in the research, development, demonstration, and commercial application programs for fossil energy at the DOE.
- *“Nuclear”* — Would require the U.S. Secretary of Energy to submit a report assessing the DOE’s ability to host privately funded fusion and fission reactor prototypes.
- *“Workforce Development”* — Would establish a three year pilot program to award competitive grants for job training programs that lead to an industry-recognized credential.

Title IV, "Accountability"

Title IV of the proposed Energy Policy Modernization Act of 2015 includes the following provisions:

- *"Loan Programs"* — Contains provisions related to (1) clarifying and reaffirming the current prohibition on subordination of debt, (2) increasing transparency of the loan guarantee program under Section 1703 of the Energy Policy Act of 2005, and (3) state loan eligibility.
- *"Energy-Water Nexus"* — Would establish the (1) Interagency Coordination Committee on the Nexus of Energy and Water for Sustainability (the "NEWS Committee") and (2) the Nexus of Energy and Water Sustainability Office (the "NEWS Office").
- *"Grid Reliability"* — Includes provisions related to a regional entity's submission to FERC of a reliability impact statement describing how a proposed federal rule would significantly affect the reliable operation of the BPS.
- *"Markets"* — Would establish a Working Group on Energy Markets composed of high-level agency officials and chaired by the U.S. Secretary of Energy.

Title V, "Conservation Reauthorization"

Title V of the proposed Energy Policy Modernization Act of 2015 would:

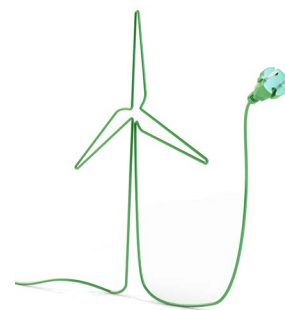
- Establish a National Park Service Critical Maintenance and Revitalization Conservation Fund.
- Permanently reauthorize the Land and Water Conservation Fund.
- Permanently reauthorize the Historic Preservation Fund.

American Energy Innovation Act of 2015 (Proposed)

Title I, "Empowering and Protecting Consumers"

Title I of the proposed American Energy Innovation Act of 2015 includes the following provisions:

- *"Access to Consumer Energy Information"* — Directs the Secretary of Energy to "encourage and support the adoption of policies that allow electricity consumers access to their own electricity data."
- *"Unfair Trade Practices Prohibition in Distributed Generation"* — Would require the Federal Trade Commission to conduct an investigation to determine whether interconnection practices are impeding the use of distributed generation.
- *"Enhanced Grid Security"* — This subtitle would:
 - Give the Secretary of Energy emergency authority to protect the BPS from cybersecurity threats.
 - Codify the designation of the DOE as the sector-specific agency for cybersecurity for the energy sector and specify the DOE's duties related to that role.
- *"Capacity Markets Study"* — Would require the GAO to study the effects of capacity mechanisms in regional electricity markets (in the Midwest, Northeast, Texas, and California) on electricity prices, consumers in general, and new power generation construction.
- *"Severe Coal Supply Emergency Response"* — Would establish consultation and coordination protocols for the Secretary of Energy, Surface Transportation Board, and FERC to address the federal response to severe coal supply emergencies.
- *"Energy Markets"* — Would establish a Working Group on Energy Markets composed of high-level agency officials and chaired by the U.S. Secretary of Energy.
- *"Transmission"* — Would require a transmission organization to submit a report to FERC within six months after the date of enactment that evaluates the characteristics, potential barriers to deployment, and potential changes to operational requirements related to distributed energy resources (DERs) and microgrid systems.



Title II, “Modernizing Infrastructure”

Title II of the proposed American Energy Innovation Act of 2015 includes the following provisions:

- “[*Quadrennial Energy Review*] Recommendations” — This set of provisions would:
 - Authorize the Secretary of Energy to lead an initiative to mitigate the risks associated with the loss of large power transformers.
 - Modernize the SPR release authorities to allow the SPR to be used more effectively in case of energy supply emergencies.
- “*Grid Modernization and Storage*” — This subtitle would:
 - Authorize a DOE research, development, and demonstration program for electric grid storage.
 - Establish a demonstration program at the DOE for the development of microgrids to enhance the resilience of critical infrastructure.
 - Authorize the DOE to develop open-source distribution planning tools and provide technical assistance to states and regional organizations so that they can develop distribution plans to modernize the grid.
- “*Advanced Manufacturing*” — Would require the establishment of the Advanced Manufacturing Office at the DOE to:
 - Carry out basic and applied research on energy-efficient processes and materials.
 - “[F]ocus on the conduct of activities that . . . use new technology and processes to reuse existing products or update existing processes to achieve energy efficiency and promote energy savings.”
 - Improve workforce development.
 - Enable domestic manufacturing competitiveness.
- “*21st Century Energy Workforce*” — Would establish a three-year pilot program to award competitive grants for job training programs that lead to an industry-recognized credential.
- “*Solar Installations*” — Would establish a program at the DOE to provide loans and grants to eligible households for residential solar installations in underserved areas with little solar deployment, including the construction of community solar facilities.
- “*Local Energy Supply and Resiliency*” — Would establish a loan program to help states, tribes, utilities, and universities deploy projects that (1) recover or produce useful thermal energy from waste heat or renewable thermal energy sources, (2) generate electricity locally, (3) distribute electricity in microgrids, (4) distribute thermal energy, or (5) transfer thermal energy to building heating and cooling systems.
- “*Geothermal Energy Opportunities*” — Addresses matters related to:
 - National goals for production and site identification.
 - Facilitation of coproduction of geothermal energy on oil and gas leases.
 - Large-scale geothermal energy.
- “*Clean Coal Technology Research*” — Would expand the research, development, and deployment objectives of the DOE’s Office of Fossil Energy by adding an explicit objective to improve the conversion, use, and storage of CO₂ from coal and other fossil fuels.
- “*Long-Term Contracts*” — Would authorize the federal government to enter into contracts with terms of up to 30 years for the acquisition of renewable energy or energy from cogeneration facilities.
- “*Promoting Renewable Energy with Shared Solar*” — Would allow community solar projects of up to 2 MW in size to be connected to their power distribution system.
- “*Loan Programs*” — Contains provisions related to (1) clarifying and reaffirming the current prohibition on subordination of debt, (2) increasing transparency of the loan guarantee program under Section 1703 of the Energy Policy Act of 2005, and (3) state loan eligibility.

Title III, “Cutting Pollution and Waste”

Title III of the proposed American Energy Innovation Act of 2015 includes the following provisions:

- *“Carbon Savings Goal”* — Would set a U.S. policy goal of reducing greenhouse gas emissions in the United States by at least 2 percent annually on average through 2025.
- *“American Energy Efficiency”* — Would set parameters for a national energy efficiency resource standard (EERS), which would be administered by each state:
 - The DOE would be required to issue a rule to implement the EERS within one year of passage of this legislation.
 - Under the EERS, retail electric and gas utilities would need to reduce their energy use by 1 percent in 2017. The standard would increase each year and require a 20 percent reduction by 2030. After 2030, the DOE would be required to issue new standards for the next 10 years.
 - States that exceed the standard for a given year would be able to apply the additional savings to future years.
- *“Energy Efficiency Retrofit Program”* — Would establish a pilot program to retrofit nonprofit buildings with energy efficiency improvements.
- *“Weatherization Enhancement and Local Energy Efficiency Investment and Accountability”* — This set of provisions would:
 - Reauthorize the Weatherization Assistance Program from 2016 through 2020 with an authorization level of \$450 million for each fiscal year.
 - Authorize grants to promote energy and water conservation improvements for low-income multifamily residential units.
 - Reauthorize the State Energy Program for fiscal years 2016 through 2020 at a funding level of \$75 million for each fiscal year.
- *“Utility Energy Service Contracts Improvement”* — Would extend the maximum contract period of utility energy service contracts entered into by federal agencies from 10 years to 25 years.
- *“State Residential Building Energy Efficiency Loan Pilot Program”* — Would authorize a program to provide loans to a state, territory, or tribal organization for establishing or expanding programs aimed at providing financing for energy efficiency upgrades to residential buildings.
- *“Smart Energy and Water Efficiency”* — Would establish a pilot program for municipalities, utilities, water districts, or any other authority that provides water, wastewater, or water reuse services to demonstrate novel and innovative technology-based solutions to increase the energy efficiency and water conservation in water, wastewater, and water reuse systems.
- *“Regional Energy Partnerships”* — Would help facilitate the development of regional energy partnerships to coordinate and promote national, regional, and state energy goals, especially goals focused on advancing resilient energy systems to mitigate risks and prepare for emerging energy challenges.
- *“Energy Productivity Innovation Challenge”* — Would require the U.S. Secretary of Energy to invite states to participate in an electric and thermal energy productivity challenge aimed at doubling electric and thermal energy productivity by January 1, 2030:
 - Up to 25 states would be eligible to receive grants of \$500,000 to \$1.75 million by submitting a revised state energy conservation plan that demonstrates how the state intends to increase its electric and thermal energy productivity.
 - No later than 18 months after receiving a grant under Phase 1, each state may report to the Secretary of Energy on its performance and how additional funds would support the proposed efforts.
- *“Smart Buildings”* — Would require the Secretary of Energy to conduct a survey of privately owned smart buildings across the nation, including commercial buildings and buildings owned by nonprofit organizations and institutions of higher education.



- *“Energy Study”* — Would require the Secretary of Energy, within two years of enactment, to submit to Congress a study on the impact of:
 - *“State and local performance benchmarking and disclosure policies, and any associated building efficiency policies, for commercial and multifamily buildings.”*
 - *“[P]rograms and systems in which utilities provide aggregated information regarding whole building energy consumption and usage information to owners of multitenant commercial, residential, and mixed-use buildings.”*

Title IV, “Investing in Research and Development”

Title IV of the proposed American Energy Innovation Act of 2015 would authorize:

- \$15 billion in funding for basic research at the DOE for each fiscal year from 2016 through 2020.
- \$1 billion in funding for the Advanced Research Project Agency — Energy (ARPA-E) for each fiscal year from 2016 through 2020.

Title V, “Investing in Clean Energy”

Title V of the proposed American Energy Innovation Act of 2015 includes the following provisions:

- *“Clean Energy Tax Credits”* — Would create a performance-based incentive that would be neutral and flexible between clean electricity technologies.
- *“Clean Fuel Tax Credits”* — Would create a technology-neutral incentive for the domestic production of renewable transportation fuels.
- *“Energy Efficiency Incentives”* — Would create performance-based incentives for new and existing homes. The credits would be based on the overall level of energy reduction.
- *“Clean Electricity and Fuel Bonds”* — Would create a tax credit bond for facilities producing clean electricity or clean transportation fuels.

Title VI, “Conservation Reauthorization”

Title VI of the proposed Energy Policy Modernization Act of 2015 would:

- Establish a National Park Service Centennial Fund.
- Permanently reauthorize the Land and Water Conservation Fund.
- Permanently reauthorize the Historic Preservation Fund.

North American Energy Security and Infrastructure Act of 2015 (Proposed)

The proposed North American Energy Security and Infrastructure Act of 2015 includes measures on gas infrastructure siting, energy efficiency, electric grid reliability, and security.

House Energy and Commerce Committee Chairman Fred Upton (R-Michigan) added a manager’s amendment to the bill to study the performance of RTO capacity markets, advance clean coal research and development, establish LNG export approval deadlines, and extend hydropower production incentives through 2025.

Acknowledging that the CPP and other environmental rulemakings could cause reliability problems, the manager’s amendment requires FERC and NERC to conduct a special reliability analysis when any federal agency issues a rule that could affect electric generating units. The required study would examine how the rule would affect not only reliability and resource adequacy, but also the electricity generation portfolio, the operation of wholesale electricity markets, and electric transmission and natural gas pipeline infrastructure.

In addition, the House Energy and Commerce Committee adopted an amendment that would require state public utility commissions to study whether approving rooftop solar panel projects would benefit only users of the panels, shift costs to lower-income consumers, or negatively affect fuel diversity or grid security.

Key provisions of the bill are outlined below.

Title I, “Modernizing and Protecting Infrastructure”

Title I of the proposed North American Energy Security and Infrastructure Act of 2015 includes measures related to:

- “FERC process coordination.”
- “Resolving environmental and grid reliability conflicts.”
- “Emergency preparedness for energy supply disruptions.”
- “Critical electric infrastructure security.”
- The establishment of a “Strategic Transformer Reserve.”
- The establishment of “a voluntary Cyber Sense program to identify and promote cyber-secure products intended for use in the bulk-power system.”
- “State coverage and consideration of PURPA standards for electric utilities.”

Title II, “21st Century Workforce”

Title II of the proposed North American Energy Security and Infrastructure Act of 2015 would provide for the development of the energy and manufacturing workforce.

Title III, “Energy Security and Diplomacy”

Title III of the proposed North American Energy Security and Infrastructure Act of 2015 contains provisions related to:

- “Sense of Congress.”
- “Energy security valuation.”
- The “North American energy security plan.”
- “Collective energy security.”
- The development of a “Strategic Petroleum Reserve mission readiness plan.”

Title IV, “Energy Efficiency and Accountability”

Subtitle A, “Energy Efficiency”

Subtitle A of Title IV includes the following provisions:

- “Federal Agency Energy Efficiency”:
 - “Energy-efficient and energy-saving information technologies.”
 - “Energy efficient data centers.”
 - “Report on energy and water savings potential from thermal insulation.”
 - “Federal purchase requirement.”
- “Energy Efficient Technology and Manufacturing”:
 - “Inclusion of Smart Grid capability on Energy Guide labels.”
 - “Voluntary verification programs for air conditioning, furnace, boiler, heat pump, and water heater products.”

- “Facilitating consensus furnace standards.”
- “Future of Industry program.”
- “Energy Performance Contracting” — “Use of energy and water efficiency measures in Federal buildings.”
- “School Buildings” — “Coordination of energy retrofit assistance for schools.”

Subtitle B, “Accountability”

Subtitle B of Title IV includes the following provisions:

- “Market Manipulation, Enforcement, and Compliance” — “FERC Office of Compliance Assistance and Public Participation.”
- “Market Reforms” — “GAO study on wholesale electricity markets.”

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 October 5, 2015, there were 99 nuclear units operating in the United States, of which 76 have received license extensions and 16 have pending applications.

Four 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.

Industry insiders expect more retirements to come in the near future, and there are at least 12 nuclear units “at risk” for early retirement because of market conditions as identified by UBS, Moody’s, and Fitch Ratings. Supporting this expectation are (1) Entergy Corp.’s announcement on October 13, 2015, that it will retire its Pilgrim plant in Plymouth County, Massachusetts, no later than June 1, 2019, and (2) the company’s announcement on November 2, 2015, that it will retire its FitzPatrick plant in Scriba, New York, by late 2016 or early 2017. This is in addition to Exelon Corp.’s announcement in 2010 that it will retire its Oyster Creek Generating Station in New Jersey in 2019, which is 10 years before license expiration in 2029. There are only one newly commissioned unit and four new units on the horizon, so the potential decline becomes clear.

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 table below 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 October 3, 2015, announced to retire no later than June 1, 2019.

** On November 2, 2015, announced to retire in late 2016 or early 2017.

*** Exelon Corp. and Berkshire Hathaway Energy.

**** Exelon Corp. and EDF Group.

***** Exelon Corp., EDF Group, and Long Island Power Authority.

Source: SNL Energy

The nuclear units identified above, including Pilgrim and FitzPatrick, have an aggregate capacity of 10,583 MW. Of these nuclear units, only two are rate-regulated (Quad Cities BWR 1 and 2) and the remaining 10 are merchant plants. Fitch Ratings identified in its January 7, 2015, report that (1) regulated-unit retirements are caused by extended outages where the repair costs are high and (2) merchant plant closures are driven by market conditions that limit the recovery of rising operating and capital costs.

Exelon Corp. announced on September 10, 2015, that all of its nuclear plants in the PJM market cleared in the transition capacity auction for the 2017–2018 planning year and that it will defer any decisions about the future operations of its Quad Cities and Byron nuclear plants for one year. As a result, it plans to continue operating its Quad Cities nuclear plant through at least May 2018. The Byron nuclear plant is obligated to operate through May 2019.

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 a combined license (seven projects) or for an early site permit (one project) is primarily associated with projects of utilities that investors own either wholly or in partnership with other companies, including municipal utilities.

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 first 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 Nuclear Regulatory Commission (NRC) on October 22, 2015. The TVA does not expect to begin commercial operations until early 2016, following a period of fuel load, testing, and NRC inspection. When Unit 2 begins operations, 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 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 Public Service Commission are more than \$7.5 billion, with scheduled completion dates in 2019 and 2020, respectively.

The owners of Vogtle filed a \$900 million lawsuit against the contractors, Westinghouse Electric Co. LLC and Chicago Bridge & Iron Co. NV, regarding who was responsible for cost overruns incurred before construction began in 2012. On October 27, 2015, the contractors announced that Westinghouse Electric Co. LLC will be acquiring all of the outstanding equity interest in Chicago Bridge & Iron Co. NV's nuclear construction business. This announcement signals the end of the lawsuit since all parties have agreed on terms to settle all claims.

- *Virgil C. Summer Nuclear Generating Station Units 2 and 3* — In March 2012, the NRC issued construction and operating licenses for the two proposed reactors at the Virgil C. Summer plant in South Carolina. Two-thirds of the plant is owned by the operator, SCANA Corp. subsidiary South Carolina Electric & Gas Co., and one-third is owned by the South Carolina Public Service Authority (also known as Santee Cooper). There have been multiple delays with the construction of the reactors. The estimated initial costs for Units 2 and 3 were \$6.3 billion, with scheduled completion dates in 2016 and 2019, respectively. The most recent estimated costs are \$7.1 billion, with scheduled completion dates in 2019 and 2020, respectively.

Improving Efficiency

The Nuclear Energy Institute (NEI) announced on December 8, 2015, that it is launching an initiative in which it will work with plant operators to improve efficiency. The goal of the initiative is to maintain and increase reliability while reducing costs by 30 percent. Nuclear power provides approximately one-fifth of U.S. electricity, but the combination of recent retirements and announced retirements of nuclear reactors is threatening the amount of production.

NEI's efficiency initiative could benefit all plants since income is being eroded by rising costs of producing nuclear power. According to statistics from NEI, the total average electric generating costs at U.S. plants increased by 28 percent over 12 years, to \$36.27 per MWh in 2014. One of the biggest factors making nuclear power more expensive is the rapidly increasing cost of capital expenditures. According to NEI, the cost of capital expenditures increased by 109 percent from 2002 to 2014. Many nuclear plants will continue to require significant investment to address aging components since some plant operators are preparing to maintain operations for up to 80 years.

Clean Power Plan and Nuclear Power

The CPP (Section 111(d) of the Clean Air Act) establishes statewide CO₂ emission standards for existing fossil-fuel-fired electric generating units with the goal of cutting CO₂ emissions by 32 percent as measured from a 2005 baseline by 2030. The EPA's final rule details three building blocks for compliance and allows states to choose between rate-based and mass-based compliance approaches. States can also adopt a trading program under either approach, which would allow power plants to trade either emission rate credits under a rate-based approach or allowances under a mass-based approach.

States that are expecting large quantities of nuclear power to come online in the next decade will automatically generate a large quantity of credits that can be directly used for compliance under a rate-based approach instead of a mass-based compliance approach. States with early retirements of nuclear power plants could experience the opposite effect since fewer credits will be generated under the CPP and achieving emission reductions could be more challenging. Emissions rates are calculated by placing the emissions in pounds over a set number of megawatt hours.

Tennessee, South Carolina, and Georgia are expected to have new nuclear reactors energized in the years preceding the CPP's 2022 compliance date. As discussed above, the TVA completed construction of the second Watts Bar unit in Tennessee in October 2015, Southern Co. is building two new reactors at the Vogtle nuclear plant in Georgia, and SCANA Corp. subsidiary South Carolina Electric & Gas Co. is building two reactors at the Virgil C. Summer nuclear plant in South Carolina. These three states are "leaning" toward rate-based compliance plans because of their nuclear fleets, whereas the rest of the states are considering the development of mass-based compliance plans. It should be noted that under the CPP, rate-based states cannot trade with mass-based states.

NEI believes that nuclear power can offer benefits in a rate- and mass-based compliance plan by either making it easier for states to meet rising electricity demand without eating into an emissions cap or offsetting the loss of fossil-fueled power plants that cannot meet a rate-based emissions intensity limit.

NRC Regulations and Other Activity

On October 27, 2015, the NRC decided that more than a dozen U.S. reactors will not have to submit in-depth analyses of their exposure to earthquake risks, while many other reactors found to be particularly vulnerable to seismic activity will have to submit their analyses earlier than previously scheduled. Since the Fukushima Dai-ichi Nuclear Plant disaster in Japan, the NRC has been requiring U.S. nuclear plants to use more modern measurement techniques to evaluate how their facilities could withstand an earthquake.

Plants have completed measurements of potential ground-motion acceleration around their sites, and for the more than 30 plants that registered particularly high in these measurements, the NRC in 2014 determined that these plants must do more in-depth analyses of their seismic risks. But the NRC has now concluded that assessments are unnecessary for 13 of those sites. The remaining plants for which the risk assessments have been deemed necessary will have to submit their analyses from as little as three months to as much as one year earlier than expected.

During 2016, the nuclear industry hopes to announce that "lead plants" will try to become the first ones to receive license extensions to operate for up to 80 years. Nuclear plants were originally granted 40-year operating licenses, with many operators already receiving 20-year extensions. This is seen as a critical regulatory step to prevent the amount of nuclear power in the United States from declining sharply. Persuading the NRC to take the unprecedented step of licensing a plant to operate beyond 60 years could set a path for the whole industry to follow. Dominion Resources Inc. announced on November 6, 2015, that it will be submitting a letter to the NRC indicating its intent to file a second renewal application for its 1,676-MW Surry nuclear plant for 20 years. The second renewal application is a way for the company to take advantage of the greenhouse-gas-emissions-free asset. Dominion Resources Inc. expects a formal renewal submittal to the NRC in 2019. The Surry nuclear plant has two reactors that were originally licensed for 40 years, and the licenses were renewed in 2003 for 20 additional years. The current licenses expire in 2032 and 2033. If the renewal application is approved by the NRC, Surry would be one of the first plants to receive a second extension.

Another candidate to be a lead plant is Florida Power & Light Co., a subsidiary of NextEra Energy Inc. The operating licenses of two of its four nuclear reactors, Turkey Point Units 3 and 4, are currently set to expire in 2032 and 2033, respectively.

If Florida Power & Light Co. is not granted license extensions, by 2034 more than a quarter of the nuclear reactors in the United States, representing about 2 percent of total U.S. power supply, could be retired. Florida Power & Light Co. is determining whether there are any "fatal flaws" that could make an 80-year operation untenable. These flaws could be

technical issues, as well as economic barriers, and will have to emerge from the rules the NRC sets for an 80-year license application.

Nuclear Waste

Companies with closed reactors are using decommissioning trust funds set aside for dismantling to 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 been granting exemptions from those rules every time it is asked.

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 triggered by the failure to date of the DOE to open a permanent disposal site for spent nuclear fuel at Nevada's Yucca Mountain, but that plan has been derailed by a lack of funding from Congress.

That has left reactors redesigning the racks in their spent fuel pools to accommodate more of the waste and expanding 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, 7 days a week.

Demand-Side and Distributed Energy Resources

California

On June 10, 2015, CAISO issued a proposal to allow small-scale DERs to be aggregated and bid into the grid. DERs are defined as distributed renewable generation resources, energy efficiency, energy storage, electric vehicles, and demand-side technologies. If the proposal is approved, California would become the first state to integrate and manage small-scale DERs in a fashion similar to how larger utility-scale renewable resources are integrated and managed.

Key details about the proposal are as follows:

- DERs in California currently have to be 500 kW or larger to participate in grid markets. To meet this threshold, small-scale resources would have to be aggregated together.
- Also, resources must have high-accuracy metering and the ability to transmit real-time data to CAISO's control center to be dispatchable resources.
- The proposed rule would create a new class of grid participants called distributed energy resource providers (DERPs) that would be responsible for aggregating, metering, and providing the real-time data that small-scale resources would not otherwise be able to provide individually.
- There would be some constraints, such as limiting the type of resources aggregated to the same resource type (e.g., solar, storage) and requiring that DERs be aggregated to the same node.
- Demand reduction would continue to be managed under existing CAISO demand reduction aggregation programs.

By creating DERPs to manage the challenge of behind-the-meter resources, California's approach promises to be instructive to other grid operators' efforts to bring DERs into the grid.

On August 13, 2015, the California Public Utilities Commission (CPUC) issued a proposed decision (R. 14-10-003), which seeks to create a regulatory framework to provide consistency for the integration of demand-side resources and DERs. CPUC's intention with this rulemaking is to contemplate the best way to integrate these resources that considers both demand-side management (what utilities offer customers) and demand-side resources (what customers offer utilities). The proposed framework would consider the interaction of demand-side resources on an individual customer's energy usage as well as the electric distribution system as a whole and the corresponding impact of both. Also, the proposed framework would include relevant valuation methods and sourcing mechanisms.

Development of the final rule will be completed in two phases. Phase I will develop the framework for integrating demand-side resources, and Phase II will consider the use of pilot projects to explore DER sourcing mechanisms. To provide clarity between the concepts of integration of demand-side resources and demand-side management, the following definitions have been adopted:

- Integration of demand-side management is the policy and program framework that the CPUC, the utilities, and others offer to customers.
- Integration of demand-side resources is the collective actions of the customers, the CPUC, the utilities, and CAISO to optimize demand-side resources to the extent possible.

The framework will help determine how to implement tariffs, contracts, or other sourcing mechanisms for the deployment of cost-effective DERs proposed by regulated utilities in their Distributed Energy Resource Plan (R. 14-08-013) filings with the CPUC. It will also consider the adoption of localized incentives and the method that should be used for determining such incentives.

This proceeding addresses some of the same issues as the R. 14-08-013 proceeding, except this one is much broader. In the R. 14-08-013 proceeding, the CPUC seeks to determine the value of the DERs that may meet system needs and the identification of tariffs, contracts, or other mechanisms for their cost-effective deployment. R. 14-10-003 creates the framework for sourcing the resources identified in R. 14-08-013 and determining how to implement the tariffs, contracts, or other mechanisms identified. The two proceedings will work together to create an end-to-end framework that will enable a utility to move toward better integration of demand-side resources and DERs into its distribution system planning process, operations, and investment strategy.

Also, on October 22, 2015, the CPUC decided to allow Southern California Gas Co. to provide distributed electricity generation services to companies that want to use on their properties combined heat and power, fuel cells, waste heat to power, and mechanical drive technology systems fueled in whole or in part by natural gas, biogas, hydrogen, and other gaseous fuels. The CPUC approved the application for a DER tariff, concluding that providing such distributed electricity generation services is in the public interest because it meets demand in underserved markets for smaller customers. The CPUC decision establishes a limit of 20 MW per system.

New York

On February 26, 2015, the NYPSC issued an order (Case No. 14-M-0101) in an effort to revamp the state's utility business model, the Reforming the Energy Vision initiative (NY REV). The order focuses on the integration of DERs, which will make the electric power system more efficient, and engaging customers in their energy use. The order will be implemented in three phases or tracks. Subsidiaries of Consolidated Edison Inc., Fortis, Inc., Iberdrola USA Inc., and National Grid plc will oversee the integration of DERs.

Under Track 1 of the order, existing utilities will (1) act as distributed system platform providers (DSPPs) and (2) create a market and physically integrate the DERs into system operations. Items such as distributed generation, demand-response, storage, and energy efficiency are considered to be DERs.

There will be limits on the ability of utilities to be directly involved in DER markets, and they generally will not own DERs unless a system need is not being met by the market. NY REV has three exceptions:

- For energy storage integrated into distributed system architecture to ensure system reliability or enable penetration of more distributed generation into the system.
- To increase participation of DER activities by customer sectors underserved by markets, particularly low- and moderate-income customers.
- Demonstration projects.

There are also protective measures, including NYPSC monitoring of utility performance and establishment of a dispute resolution process. Utility affiliates will generally be allowed to participate in competitive markets run by their affiliated utilities with some restrictions.

Utilities were required to file plans for demonstration projects by July 1, 2015, which were meant to test hypotheses regarding the changing utility business model or platform functionality with formalized pilot projects. Utilities were also required to file distribution system implementation plans by December 15, 2015, to adapt to an environment of increasing DER penetration.

Track 2 of the order will include new earnings opportunities, new incentives, ratemaking reform, and proposals on changes to rate design. Track 3 will be focused on the development and procurement of large-scale renewables.

The table below, which is reproduced from *Integration of DER: California and New York* (ScottMadden, September 30, 2015), illustrates some critical differences and similarities between California’s approach to DER integration under Public Utilities Code Section 769 and that of New York under NY REV:

Some Critical Differences		
Attribute	California [Public Utilities Code] Section 769	[NY] REV
Market Development and Design	<ul style="list-style-type: none"> • Leverage the CAISO market • Allow aggregation of DER by third parties for bidding into the wholesale market 	<ul style="list-style-type: none"> • Use the market to defer or replace traditional utility infrastructure investments (e.g., [Brooklyn Queens Demand Management]) • Create a distribution-level market for DER and energy services
Cost/Benefit Analyses	<ul style="list-style-type: none"> • Use a [locational net benefits methodology (LNBM)] based on E3 Cost Effectiveness Calculator <ul style="list-style-type: none"> ◦ Covers costs (avoided or incurred) related to energy, capacity, ancillary services, interconnection, and externalities 	<ul style="list-style-type: none"> • Use a [benefit cost analysis framework (BCA)] to evaluate non-traditional solutions against traditional infrastructure <ul style="list-style-type: none"> ◦ Consists of three tests covering similar attributes to CA LNBM
Rate Reform	<ul style="list-style-type: none"> • Consider proposed changes to rate design and tariffs in separate proceedings • Acknowledges links to general rate cases 	<ul style="list-style-type: none"> • Propose to revamp incentives and rate design to transition utilities from rate-based revenue to market-based revenue <ul style="list-style-type: none"> ◦ Significant rate design changes • Create a location-based price signal for Locational Marginal Price plus the Value of Distribution (LMP + VoD)
Data Sharing	<ul style="list-style-type: none"> • Develop a procedure for sharing grid conditions • Focus on bi-directional data sharing 	<ul style="list-style-type: none"> • Develop a procedure for sharing grid conditions and serve as data intermediary between market participants

Some Similarities		
Attribute	California [Public Utilities Code] Section 769	[NY] REV
Demonstration Projects	<ul style="list-style-type: none"> Develop demonstration projects to test prescribed hypotheses 	<ul style="list-style-type: none"> Develop demonstration projects to test utility-defined hypotheses, based on [public service commission] goals <ul style="list-style-type: none"> Focus on markets, rate design
Planning and Operation	<ul style="list-style-type: none"> Ensure coordination with transmission planning Optimize grid planning and operation at the distribution level 	<ul style="list-style-type: none"> Optimize grid planning and operation at the distribution level
DER Interconnection	<ul style="list-style-type: none"> Reduce barriers to DER interconnection 	<ul style="list-style-type: none"> Reduce barriers to DER interconnection

Texas

On October 12, 2015, the PUCT unveiled a strawman proposal with two amendment options to the state’s utility code with the aim of better defining with whom a utility can execute distributed generation interconnection agreements since on-site resources may be owned or operated by parties other than the utility’s end-use customer. Option 1 would have only the end-use customer execute the agreement, and Option 2 would allow parties other than an end-use customer execute the agreement.

Comments were filed with the PUCT on or before October 26, 2015, by various stakeholders, with many in the solar industry in favor of Option 2 so there is flexibility to accommodate multiple entities and all potential solar distributed generation arrangements. Also, Option 2 is viewed as the better amendment to facilitate continued growth of small-scale distributed renewable generation.

Texas utilities hold an opposite view and favor Option 1, as indicated in their joint comments. There is nothing in the Public Utility Regulatory Act that allows a noncustomer to apply to interconnect a distributed generation facility with the utility’s system. The utilities that filed the joint comments are AEP Texas Central Co., AEP Texas North Co., CenterPoint Energy Houston Electric LLC, El Paso Electric Co., Entergy Texas Inc., Oncor Electric Delivery Co. LLC, Sharyland Utilities LP, Southwestern Electric Power Co., Southwestern Public Service Co., and Texas-New Mexico Power Co.

The Texas Industrial Energy Consumers also preferred Option 1 because it believed that the rules should be limited to installations designed for end-use customers that buy power for purposes unrelated to owning or operating a generation facility.

The PUCT staff had asked for guidance on the interconnection issue from the agency’s commissioners in August 2015, after which the proceeding was opened. On October 29, 2015, a workshop was held for stakeholders to provide feedback on the amendments. On the basis of the tentative proceeding schedule, a proposal for publication was expected to be presented at the PUCT’s January 7, 2016, meeting, followed by a proposal for adoption presented at the May 12, 2016, meeting. (Project No. 45078)

The ERCOT, meanwhile, has also been working on distributed generation in the hopes of opening the door for its greater use in the state. The Distributed Resource Energy and Ancillaries Market (DREAM) task force held its first meeting in August 2015, and its latest monthly meeting was held on October 26, 2015.

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, both grid-scale and distributed; (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 appears to be 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 is 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. 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:

- *California* — On October 17, 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.
- *Arizona* — On April 27, 2015, Tucson Electric Power issued a request for proposals seeking a project partner to build and own a 10-MW energy storage facility under a 10-year agreement that would be operational by the end of 2016. The company has plans to reduce its overall coal generation capacity by more than 30 percent over the next five years by increasing use of renewable power, energy efficiency, and natural-gas generation.
- *Massachusetts* — On June 1, 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. The initiative will also fund demonstration projects. The state’s Department of Energy Resources will work with the Massachusetts Clean Energy Center to assist in the development of projects and is holding forums on the subject.

In July 2015, the Massachusetts Senate passed legislation to lift the cap on net metering to 1,600 MW, which is consistent with the state’s goal of installing 1,600 MW of solar power generation by 2020. Massachusetts Governor Charlie Baker has proposed a bill to raise private and public caps by 2 percent each. On November 17, 2015, the Massachusetts House of Representatives passed a bill that increases the cap on net metering by 2 percent for both private and public facilities. The Senate and House of Representatives bills will need to be reconciled.

- *Oregon* — On June 10, 2015, Oregon Governor Kate Brown signed into law House Bill 2193-B, which requires certain electric companies to procure qualifying energy storage systems by January 1, 2020, subject to authorization by the Oregon Public Utility Commission. 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. The new law defines an “energy storage system” to be a technology that is capable of retaining energy, storing the energy for a period, and delivering the energy after storage.
- *New York* — Energy storage is an important component of NY 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.



Since 2014, a total of eight battery energy storage units with an aggregate capacity of 24 MW and two flywheel units totaling 16 MW have come online, all stand-alone systems. But the largest amount of activity is likely still to come, with California and its 1,325-MW-by-2020 storage procurement target mentioned above.

The largest energy storage project sited at a plant as of October 12, 2015 is the Rice Solar Energy Project, with a planned storage capacity of 150 MW. The plant is located in Riverside County, California, and is expected to come online in June 2017.

There are a total of 24 stand-alone battery energy storage projects in different stages of development as of October 12, 2015, according to SNL Energy's analysis — 12 projects with an aggregate capacity of 175 MW are in the "announced" stage, 4 projects totaling 134 MW are in the "early development" stage, and the remaining 8 projects are "under construction" with a total capacity of 62 MW.

The 1,200-MW Pathfinder CAES Facility in Millard County, Utah, was the largest compressed-air energy storage (CAES) project as of October 12, 2015. The plant consists of eight 150-MW CAES units that are expected to come online in 2023.

On November 13, 2015, AES Corp. began operations of its battery-based energy storage system at the Warrior Run facility in Allegany County, Maryland. The 10-MW Warrior Run array is interconnected to PJM and is equivalent to 20 MW of flexible resource, according to AES Corp. On November 17, 2015, Duke Energy, LG Chem, and Greensmith completed a 2-MW battery-based energy storage system at the site of Duke Energy's closed W.C. Beckjord coal-fired power plant. The system is actively regulating electric grid frequency for PJM.

For more information, see the Deloitte Center for Energy Solutions' September 2015 [Electricity Storage — Technologies, Impacts, and Prospects](#).

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 exchange surplus kWh of electricity they produce on distributed generation technologies during the day for grid-produced kWh at night. This mechanism may allow some customers to zero-out their monthly bills and shift an added burden onto non-distributed-generation customers for paying electric utilities' fixed costs.

Some examples of regulators dealing with net metering include:

- *Arizona Corporation Commission* — On October 20, 2015, the Arizona Corporation Commission decided to hear testimony from multiple parties on distributed solar generation before Arizona Public Service Co. could make another request to raise its solar charge for rooftop solar customers. The commissioners decided to dismiss Arizona Public Service Co.'s previous request to raise its solar charge from 70 cents per kW to \$3 per kW and instead voted 3–2 to open a generic docket to receive written comments and hear testimony from many parties about whether solar customers cost utilities more than they pay in rates or whether the value of distributed solar benefits somehow makes up for those costs.
- *CPUC* — A.B. 327, passed in 2013, directs utilities to offer a net energy metering (NEM) tariff without a cap and allows the CPUC to revise the standard contract or tariff as appropriate. Public Utilities Code Section 2827.1(c) states, "There shall be no limitation on the amount of generating capacity or number of new eligible customer-generators entitled to receive service pursuant to the standard contract or tariff after July 1, 2017." NEM is limited to solar resources no greater than 1 MW. Further, Public Utilities Code Section 2827.1(b)(5) directs the commission to allow projects greater than 1 MW that do not have a significant impact on the distribution grid to be built to the size of the on-site load.

On August 3, 2015, utilities and solar and consumer groups submitted conflicting responses to a CPUC administrative law judge’s ruling seeking proposals for a successor tariff to replace the current NEM. The solar industry wants to keep the tariff “as is,” and the utilities want to impose new charges on rooftop solar customers. On December 15, 2015, the CPUC rejected several recommendations by the utilities. Under the CPUC’s plan, new solar customers would face a one-time fee for connection to the electric grid ranging from \$75 to \$150 per solar customer. In addition, rooftop solar customers would pay 2–3 cents per kWh for electricity no matter how much power their systems generate. New solar customers would pay time-of-use rates. Existing solar customers would be exempted from all of the changes for 20 years from when their systems were installed and connected to the grid. The CPUC will review public comments on the proposed fees submitted through mid-January 2016, and a final decision is expected at the CPUC’s January 28, 2016, meeting.

- *Hawaii Public Utilities Commission (HPUC)* — On October 14, 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 have been paying. The new tariff is effective immediately and will vary for each island grid. Also, to help cover the fixed costs of providing grid service, new residential solar PV system owners will pay a minimum monthly bill of \$25. The reduced credit rates will apply to new solar customers and not those with rooftop solar systems already installed unless existing customers want to modify their current systems. The HPUC will continue to examine the costs and benefits of distributed solar as part of a second phase of the proceeding (Docket No. 2014-0192).
- *Wisconsin Public Service Commission (WPSC)* — In 2014, Wisconsin Electric Power Co. (d/b/a We Energies) asked the WPSC to approve higher fixed charges, a demand charge on solar customers, and lower payments for excess power sold by the ratepayers to We Energies. The WPSC approved all three items in December 2014. In January 2015, the Alliance for Solar Choice and RENEW Wisconsin filed a petition for judicial review in Dane County Circuit Court. On October 30, 2015, a judge ruled that the customers of We Energies who want to install solar panels do not have to pay the extra fees that are scheduled to start in 2016. The judge decided that the WPSC did not have enough evidence to support its decision in December to impose the fees. Several other parts of the We Energies rate-case decision were not challenged and were allowed to proceed. We Energies will reduce the rate it pays customers to buy the electricity they generate.
- *Mississippi Public Service Commission (MPSC)* — On December 3, 2015, the MPSC unanimously voted to adopt a net metering policy. The net metering policy includes a “two-channel” billing system. One channel is billed at the retail rate, and the second channel (excess energy) will be valued and credited to customers’ accounts at an avoided cost rate. Customers’ bill credits will have unlimited carryover. The system is similar to the one recently adopted by the HPUC described above. A key provision with the adoption is that it allows third-party ownership of rooftop solar systems, which would lead to opportunities for solar leasing businesses.

The EEI identified the increasing impact of distributed generation and associated net metering policies on the grid as a key issue for the electric utility sector. 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.

FERC Developments

Order 1000

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

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

- “Local and regional transmission planning processes must consider transmission needs driven by public policy requirements established by state or federal laws or regulations. Each public utility transmission provider must establish procedures to identify transmission needs driven by public policy requirements and evaluate proposed solutions to those transmission needs.”
- “Public utility transmission providers in each pair of neighboring transmission planning regions must coordinate to determine if there are more efficient or cost-effective solutions to their mutual transmission needs.”

Further, the order contains three requirements related to allocation of transmission costs:

- “Each public utility transmission provider must participate in a regional transmission planning process that has a regional cost allocation method for new transmission facilities selected in the regional transmission plan for purposes of cost allocation. The method must satisfy six regional cost allocation principles.”
- “Public utility transmission providers in neighboring transmission planning regions must have a common interregional cost allocation method for new interregional transmission facilities that the regions determine to be efficient or cost-effective. The method must satisfy six similar interregional cost allocation principles.”
- “Participant-funding of new transmission facilities is permitted, but is not allowed as the regional or interregional cost allocation method.”

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

However, there are four exceptions to this requirement:

- The requirement “does not apply to a transmission facility that is not selected in a regional transmission plan for purposes of cost allocation.”
- Providers in a transmission planning region are permitted, but not required, “to use competitive bidding to solicit transmission projects or project developers.”
- State and local regulations related to the construction of transmission facilities are unaffected by this requirement. Such regulations include, but are not limited to, those associated with “authority over siting or permitting of transmission facilities.”
- “[I]ncumbent transmission providers may rely on regional transmission facilities to satisfy their reliability needs or service obligations.” However, public utility transmission providers are required to amend their tariffs “to require reevaluation of the regional transmission plan to determine if delays in the development of a transmission facility require evaluation of alternative solutions, including those proposed by the incumbent, to ensure incumbent transmission providers can meet reliability needs or service obligations.”

Forty-five parties asked the D.C. Circuit to review various aspects of the order in *South Carolina Public Service Authority et al. v. FERC*. On August 15, 2014, the court of appeals rejected the pleas to overturn the order, arguing that FERC did not encroach on states’ authority in imposing regional transmission cost allocation and planning requirements and that FERC had adequately justified its decision to remove the right of first refusal. The court also upheld the rule’s requirement for jurisdictional utilities to participate in regional and interregional grid-planning processes.

In June 2015, a complaint was filed with FERC by the Coalition of Eastside Neighborhoods for Sensible Energy, the Citizens for Sane Eastside Energy, and three individuals against the Energize Eastside project (EL15-74). The complaint stated that the project was being treated by Puget Sound, Seattle City Light, and Bonneville Power Administration, members of the ColumbiaGrid transmission planning group, as a local load project and not a regional project subject to Order 1000. On October 21, 2015, FERC dismissed the complaint after finding that the project had been properly proposed and evaluated. FERC concluded that the project is subject to Order 890 (transmission planning requirements) and not Order 1000 (regional approval process) for a variety of reasons (e.g., the project is located completely within Puget Sound’s service territory and was included in Puget Sound’s transmission planning for meeting local reliability needs). Also, the complaint (1) did not clearly specify which actions or inactions of Puget Sound and the other ColumbiaGrid companies violated any statutory

standard or regulatory requirement and (2) did not explain how those actions or inactions did so, which is required by Federal Power Act Section 206.

On July 28, 2015, ITC Holdings Corp. asked FERC to clarify how binding bids will be considered and whether transmission developers willing to cap costs for proposed projects under Order 1000 will be shielded from later risks (EL15-86). ITC Holdings Corp.'s question to FERC is directed toward SPP and MISO, which both established 40-year annual revenue requirement estimates that span the entire lifespan of a project rather than just construction and associated costs. ITC Holdings Corp. is concerned that guaranteeing the cost of a project over a 40-year lifespan exposes developers to risk because customers have the right to request a review of rates under Section 206 of the Federal Power Act. It also asked whether any cost savings that are realized when a project developer assumes cost overruns can benefit the developer and thus provide an incentive to participate in competitive projects.

PJM and CAISO have conducted competitive solicitations for new projects under Order 1000, while SPP had one competitive solicitation open as of November 1, 2015. MISO has not yet conducted a competitive solicitation for a new project under Order 1000. PJM and CAISO only require that developers bid on project costs, rather than full revenue requirements that would include operations and maintenance, staffing, and other lifespan costs.

Formula Rate Standards

Utilities establish transmission rates by using a formula-based approach with rates updated annually. FERC requires utilities to share the annual updates to the rates with all interested parties and 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.

FERC continues to focus on increasing transparency of formula rates. On March 19, 2015, it 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.

Method for Determining Return on Equity

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

FERC applied the method to a pending complaint involving the ROE of New England Transmission Owners (NETOs), as detailed in the Commission's [Opinion 531](#). The press release notes that FERC has established "a paper hearing on the appropriate long-term growth rate to use, noting that in natural gas and oil pipeline proceedings [the Commission] uses growth in GDP as a measure of long-term growth." Opinion 531 states that the purpose of the paper hearing is to give the

ruling’s participants “an opportunity to submit briefs on an issue regarding the application [of the new approach] to the facts of this proceeding.”

On the basis of this hearing, FERC released [Opinion 531-A](#) on October 16, 2014. In this order, FERC 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 NETO’s maximum base ROE, including any incentives, cannot exceed 11.74 percent. In addition to the base ROE, 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 has 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 New England Inc.’s open-access transmission tariff.

The two other complaints were submitted in December 2012 and July 2014. FERC consolidated these two hearings but established two separate 15-month refund periods between December 27, 2012, and March 27, 2014.

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 a “hearing and settlement judge procedures” related to a complaint seeking to reduce the existing 12.38 percent base ROE earned by most Midcontinent Independent System Operator Inc. transmission organizations to no more than 9.15 percent. This complaint also argues that the current ROE does not “reflect current capital market conditions.”
- *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 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 requires Duke Energy Florida LLC to provide more than \$14 million in refunds to its various network and point-to-point service customers.

Electric Reliability

On May 15, 2015, FERC released a letter to the U.S. EPA regarding reliability issues under the proposed CPP. FERC indicated that it was willing to play a “narrow role” in the process at the EPA’s request in resolving reliability issues. On August 3, 2015, the EPA, FERC, and the DOE officially outlined a plan for addressing any electric power reliability problems that may arise under the final CPP. The joint plan outlines each agency’s role:

- FERC will monitor reliability issues.
- The EPA will engage with states and stakeholders.
- The DOE will provide technical assistance.

The three agencies will continue to coordinate while states are developing and implementing their plans under the CPP, with the EPA being the primary agency for monitoring state compliance.

The EPA also incorporated a reliability safety valve (RSV) mechanism into the final CPP. The RSV provides for (1) a 90-day period during which an affected plant would not be required to meet the CO₂ reduction standard established for it but would have to meet an alternative standard and (2) a period beginning after the initial 90 days during which the affected plant may be required to continue to operate under an alternative standard rather than under the originally envisioned standard. The RSV would apply only in a narrow set of circumstances.

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 rules 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 Supreme 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 October 14, 2015, the Supreme Court heard oral arguments, which focused largely on jurisdictional issues. The Supreme Court is likely to issue a decision in the summer of 2016.

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 does 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 addresses a market-based rate filing submitted by the Public Service Co. of New Mexico to report on a change in status, will serve to provide guidance developed after numerous companies submitted applications raising the same issues.

The draft final rule is 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.

Electric Power Price Formation

FERC’s effort regarding electric power price formation has a series of goals: ensuring the right incentives are being offered to maintain reliability, facilitating accurate and transparent pricing, reducing uplift, and enabling market participants to operate consistent with dispatch signals.

On September 17, 2015, FERC issued an [NOPR \(RM15-24\)](#) to address two practices that do not provide appropriate signals for resources to respond to actual operating needs and properly reflect system conditions and costs to serve consumers when compensating resources within organized markets. According to a [FERC press release](#), the NOPR proposes to address these matters by requiring each organized market to:

- “[A]lign settlement and dispatch intervals by settling real-time energy and operating reserves transactions financially at the same time interval that it dispatches energy and prices operating reserves.”
- “[T]rigger shortage pricing for any dispatch interval during which a shortage of energy or operating reserves occurs.”

Comments on the NOPR were due by November 30, 2015.

Many industry players are urging FERC to hold a technical conference on the NOPR to provide more specific data on entities that participate in the organized wholesale power markets. The scope of the proposed reporting changes is significant and broad but also vague. They believe that a technical conference would give participants an opportunity to better understand the proposed regulations and help ensure that the rule strikes a balance between the burden the requirements would create and FERC’s need for additional information.

On November 19, 2015, FERC issued a draft order directing the grid operators (RTOs and ISOs) to report on five issues related to their need to act outside the market and allocate associated costs, known as uplift. The RTOs and ISOs have until February 2, 2016, to respond to FERC and detail their current practices related to (1) the pricing of fast-start resources, (2) commitments to manage multiple contingencies, (3) look-ahead modeling, (4) uplift allocation, and (5) transparency. The draft order was issued to help FERC better understand how the RTOs and ISOs currently deal with these five issues. The public will have 30 days after the reports are filed to comment on them. FERC will then determine what further action is needed.



Section 2 SEC Update

Activities Related to Requirements Under the Dodd-Frank Act

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

SEC and Other Government Agencies Issue Final Rule on Credit Risk Retention

On October 22, 2014, the SEC and five other federal agencies adopted a [final rule](#) that requires securitizers, under certain conditions, to retain a portion of the credit risks associated with the assets collateralizing an asset-backed security (ABS). The final rule was issued in response to a mandate of Section 941 of the Dodd-Frank Act, which added new credit risk retention requirements to Section 15G of the Exchange Act.

The final rule addresses what some believed to be a critical weakness in the securitization market that led to the financial crisis — namely, that certain meaningful risks need to be retained to ensure that securitizers have the incentives to monitor the quality of the securities. Therefore, under the final rule, securitizers are:

- Required to retain no less than 5 percent of the credit risk of assets collateralizing an ABS.
- Prohibited from hedging or transferring the credit risk they are required to retain.

In addition, the final rule permits securitizers to select a form of risk retention obligation from a menu of specified options. The options available include (1) an eligible vertical interest, (2) an eligible horizontal residual interest, or (3) a combination of both when the combined interest is no less than 5 percent of the fair value of all ABSs issued. ABSs that are collateralized solely by “qualified residential mortgages” (QRMs) are exempt from the risk retention requirements. The final rule alters the definition of a QRM to align it with the Consumer Financial Protection Bureau’s definition of a “qualified mortgage.” The final rule became effective on February 23, 2015.

SEC Proposes Hedging Disclosure Requirements

On February 9, 2015, the SEC issued a [proposed rule](#) that would enhance corporate governance by requiring registrants to disclose employee and director information that may affect shareholders’ interests. Specifically, the proposal, which was issued in response to a requirement in Section 955 of the Dodd-Frank Act, would require a registrant to disclose, in a proxy or information statement, whether “the registrant permits any employees (including officers) or directors of the registrant, or any of their designees, to purchase financial instruments (including prepaid variable forward contracts, equity swaps, collars, and exchange funds) or otherwise engage in transactions that are designed to or have the effect of hedging or offsetting any decrease in the market value of equity securities.” Comments on the proposed rule were due by April 20, 2015.

SEC Proposes Rule on Pay Versus Performance

On April 29, 2015, the SEC issued a [proposed rule](#) that would amend Regulation S-K, Item 402, to implement a mandate under the Dodd-Frank Act requiring a registrant to disclose the relationship between executive compensation actually paid and the financial performance of the registrant. The proposal is intended to improve shareholders’ ability to objectively assess the link between executive compensation and company performance. In the proposal, the SEC has requested comments on 64 questions. Under the proposal, a company would be required to disclose, in a new table, the following information for its last five fiscal years:

- Executive compensation actually paid to its principal executive officer (PEO), which would be the total compensation amount already disclosed in the summary compensation table required in the proxy statement, adjusted for certain amounts that were not actually paid (e.g., for pensions and equity awards).

- The average compensation actually paid to the remaining named executive officers identified in the summary compensation table.
- Total executive compensation reported for the principal executive in the summary compensation table, and the average of amounts reported for the other named executive officers.
- Total shareholder return (TSR) of the company on an annual basis.
- TSR, on an annual basis, of companies in the same peer group used in the company's stock performance graph or its compensation discussion and analysis.

Comments on the proposal were due by July 6, 2015.

See Deloitte's May 29, 2015, [Heads Up](#) for additional information.

Cross-Border Security-Based Swaps

On April 29, 2015, the SEC issued a [proposed rule](#) on cross-border security-based swap transactions related to activity in the United States. As noted in an SEC [press release](#), the proposed rule would "require a non-U.S. company that uses U.S. personnel to arrange, negotiate, or execute a transaction in connection with its dealing activity to include that transaction in determining whether it is required to register as a security-based swap dealer." According to SEC Chair Mary Jo White, the proposal would "help ensure that both U.S. and non-U.S. dealers are subject to [the SEC's] registration, reporting, public dissemination and business conduct requirements when they engage in security-based swap activity in the United States, resulting in increased transparency and enhanced stability and oversight." Comments on the proposal were due by July 13, 2015.

SEC and CFTC Issue Interpretation on Forward Contracts With Volumetric Optionality

On May 12, 2015, the SEC and the Commodity Futures Trading Commission (CFTC) jointly issued an [interpretive release](#) that clarifies the CFTC's "interpretation of when an agreement, contract, or transaction with embedded volumetric optionality would be considered a forward contract." Issued in response to a Dodd-Frank Act mandate and comments from market participants, the interpretive release became effective on May 18, 2015.

New Proposed Clawback Requirements

On July 1, 2015, the SEC issued a [proposed rule](#) that would require companies to adopt "clawback" policies on executive compensation. Specifically, the proposal, which was released in response to a mandate in Section 954 of the Dodd-Frank Act, "would direct the national securities exchanges and national securities associations to establish listing standards that would require each issuer to develop and implement a policy providing for the recovery, under certain circumstances, of incentive-based compensation based on financial information required to be reported under the securities laws that is received by current or former executive officers, and require the disclosure of the policy." This proposal marks the completion of the SEC's issuance of proposed executive compensation rules under the Dodd-Frank Act. Comments on the proposed rule were due on September 14, 2015.

SEC Issues Final Rule on Pay Ratio Disclosure

On June 4, 2015, the SEC staff released an [analysis](#) of the Commission's September 2013 proposed rule on pay ratio disclosures. As explained in the SEC's [final rule](#) issued on August 5, 2015, the analysis, which was developed by the Commission's Division of Economic and Risk Analysis, examines "the potential effects of excluding different percentages of employees from the pay ratio calculation." This analysis was used in the development of the final rule.

Under the final rule, a registrant is required to calculate and disclose (1) the median of the annual total compensation of all of its employees (excluding its PEO), (2) the PEO's annual total compensation, and (3) the ratio of (1) to (2). Starting with its first full fiscal year beginning on or after January 1, 2017, the registrant will include the disclosures in filings in which executive compensation information is required, such as proxy and information statements, registration statements,

and annual reports. Emerging growth companies, smaller reporting companies, foreign private issuers, registered investment companies, and filers under the U.S.-Canadian Multijurisdictional Disclosure System are exempt from the rule's requirements.

In determining median employee compensation under the rule, a registrant generally must consider all of its employees and those of its consolidated subsidiaries, including full-time, part-time, temporary, and seasonal workers, and those working in foreign jurisdictions. Although a registrant can annualize compensation amounts considered for permanent employees who worked only part of the year (e.g., a new hire), it cannot annualize amounts for seasonal or temporary employees, nor can it make full-time equivalent adjustments for any employee. The rule became effective on October 19, 2015.

For detailed information about the rule, see Deloitte's August 6, 2015, [journal entry](#).

Navigating the Conflict Minerals Rule

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



On August 18, 2015, the D.C. Circuit upheld its April 2014 ruling that parts of the SEC's conflict minerals rule and of Section 1502 of the Dodd-Frank Act violate the First Amendment to the extent that they require issuers to disclose that their products have "not been found to be 'DRC conflict free.'" The D.C. Circuit agreed to review its April 2014 ruling in light of a separate case involving country-of-origin labeling of meat products.

For more information about the SEC's final rule on conflict minerals and the related legal proceedings, see Deloitte's August 19, 2015, [journal entry](#).

The Jumpstart Our Business Startups Act

The SEC continues to complete its rulemaking mandates under the JOBS Act.¹ Below is a summary of JOBS Act activity that has occurred since the last edition of this publication.

Revisions to Registration Requirements

On December 18, 2014, in response to the mandates in Titles V and VI of the JOBS Act, the SEC issued a [proposed rule](#) that would revise the requirements in Section 12(g) of the Exchange Act related to the thresholds for registration, termination of registration, and suspension of reporting. As stated in an SEC [press release](#), the proposal would:

¹ In April 2012, the JOBS Act was signed into law to increase American job creation and economic growth by improving access to the public capital markets for EGCs. The JOBS Act addresses topics such as "crowdfunding" transactions, increases shareholder limits that would require companies to register with the SEC, and provides accommodations to EGCs. See Deloitte's April 15, 2014, [Heads Up](#) for additional information.

- Amend “Exchange Act Rules 12g-1 through 4 and 12h-3 which govern the procedures relating to registration, 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.”
- Revise “the rules so that savings and loan holding companies are treated in a similar manner to banks and bank holding companies for the purposes of registration, termination of registration, or suspension of their Exchange Act reporting obligations.”
- Apply “the definition of ‘accredited investor’ in [Regulation D, Rule 501(a),] to determinations as to which record holders are accredited investors for purposes of Exchange Act Section 12(g)(1). The accredited investor determination would be made as of the last day of the fiscal year.”

In addition, the proposal would amend the definition of “held of record” and establish a nonexclusive safe harbor under Exchange Act Section 12(g). Comments on the proposed rule were due by March 2, 2015.

SEC Issues Final Rule to Ease Smaller Companies’ Access to Capital

On March 25, 2015, the SEC issued a [final rule](#) that amends and expands Regulation A, which exempts certain offerings from registration under the Securities Act. The rule implements a mandate in Section 401 of the JOBS Act to ease smaller companies’ access to capital. Under Regulation A before the amendments, a company could offer up to \$5 million of securities in a 12-month period and no more than \$1.5 million of those securities could be offered by the company’s securityholders. Under the new rule, a company can offer and sell up to \$50 million of securities in a 12-month period if it meets specified eligibility, disclosure, and reporting requirements. The rule creates the following two tiers of offerings under Regulation A:

- “Tier 1: annual offering limit of \$20 million, including no more than \$6 million on behalf of selling securityholders that are affiliates of the issuer.”
- “Tier 2: annual offering limit of \$50 million, including no more than \$15 million on behalf of selling securityholders that are affiliates of the issuer.”

The final rule establishes offering and reporting requirements for issuers under both tiers; however, such requirements are more extensive for Tier 2 issuers, which must provide audited financial statements in their offering documents and file annual, semiannual, and current reports with the SEC. The rule also preserves, “with some modifications, existing provisions regarding issuer eligibility, offering circular contents, testing the waters, and ‘bad actor’ disqualification.”

On June 18, 2015, the SEC staff issued [guidance](#) on its March 2015 amendments to Regulation A. The amendments, as further described above, became effective on June 19, 2015. The SEC staff also issued and revised a number of Compliance and Disclosure Interpretations (C&DIs) to provide additional guidance on Regulation A. Specifically, the staff added questions 182.01 through 182.11 under the Securities Act Rules interpretations and withdrew questions 128.01 and 128.03 from the Securities Act Forms interpretations.

The Fixing America’s Surface Transportation Act

On December 4, 2015, President Obama signed into law the Fixing America’s Surface Transportation Act (the “FAST Act” or the “Act”). Among its many provisions, the Act amends the JOBS Act and certain SEC disclosure requirements. It also establishes a new statutory exemption for private resales of securities.

The [text](#) of the FAST Act is available on the U.S. Government Publishing Office’s Web site. Some of the Act’s key provisions are discussed below.

JOBS Act Changes for IPOs of Emerging Growth Companies

Among its changes related to IPOs and EGCs, the FAST Act:

- Reduces from 21 to 15 the number of calendar days before EGCs can commence a roadshow after publicly filing a registration statement with the SEC. This provision became effective immediately.
- Provides a grace period during which an EGC can continue to receive EGC treatment for certain purposes if it loses its EGC status during the SEC review process. The grace period ends on the earlier of (1) the consummation of the issuer's IPO under the relevant registration statement or (2) one year after the issuer ceased to be an EGC. This provision became effective immediately.
- Permits EGCs to omit financial information from registration statements on Form S-1 or Form F-1 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 these historical periods will not be required to be included at the time of the contemplated offering. This provision is intended to apply in situations in which the SEC review process is likely to extend through a financial statement staleness date. Before the EGC distributes the preliminary prospectus to investors, the registration statement must be amended, if necessary, to include all financial information required by Regulation S-X as of the date of that amendment. The SEC had 30 days from the enactment date to promulgate rules effecting this change. However, issuers were permitted to omit such financial information starting on the 31st day after enactment.

On January 13, 2016, the SEC approved the issuance of [interim final rules](#) implementing certain provisions of the FAST Act. The interim final rules revise Forms S-1 and F-1 to allow for the omission of certain historical-period financial information before an offering insofar as an EGC's registration statement includes the required financial information at the time of the offering. In addition, as noted in an SEC [press release](#), the interim final rules revise Form S-1 "to allow smaller reporting companies to use incorporation by reference for future filings the companies make under the federal securities laws after the registration statement becomes effective." Further, the interim final rules include a request for comment on whether these changes should be expanded to other forms or registrants. The interim final rules will become effective upon publication in the *Federal Register*, with a 30-day comment period beginning thereafter.

Form 10-K and Regulation S-K Disclosure Changes

The FAST Act amends certain disclosure requirements related to Form 10-K and Regulation S-K. For example, the Act:

- Allows all issuers to submit a summary page on Form 10-K if each item on the summary page contains a cross-reference (which can be in the form of a hyperlink) to the material in the 10-K. The SEC has 180 days from enactment to implement this provision.
- Directs the SEC to simplify Regulation S-K and eliminate duplicative, overlapping, or otherwise unnecessary requirements for all issuers. The SEC has 180 days from enactment to implement this provision.
- Requires the SEC to study the requirements of Regulation S-K, report to Congress, and commence rulemaking on ways to (1) modernize and simplify Regulation S-K in a manner that reduces all costs and burdens on issuers, (2) emphasize a company-by-company approach that eliminates boilerplate language and static requirements, and (3) evaluate methods of information delivery and presentation that discourage repetition and the disclosure of immaterial information. The SEC has 360 days from enactment to submit the study findings and suggestions to Congress.

New Section 4(a)(7) Exemption for Private Resales

Private placement resales by persons other than the issuer, such as holders of restricted securities or affiliates of the issuer, were not eligible for Section 4(a)(2) of the Securities Act or Regulation D, which exempt private placements by issuers. New Section 4(a)(7) of the Securities Act provides a statutory exemption for private resales of restricted and control securities under certain conditions. Securities acquired in reliance on Section 4(a)(7) will be subject to transfer restrictions and covered securities will be exempt from certain "blue sky" laws. This provision became effective immediately.

Incorporation by Reference for Smaller Reporting Companies

The FAST Act allows smaller reporting companies (entities that, as of the last business day of their second fiscal quarter, have a public float of less than \$75 million) to automatically update information in a Form S-1 resale prospectus by incorporating by reference any documents filed with the SEC after the Form S-1 registration statement becomes effective. This method of updating information was previously available only to Form S-3 filers. The SEC has 45 days from enactment to implement this provision.

Compliance and Disclosure Interpretations of the FAST Act

In response to the issuance of the FAST Act, the SEC's Division of Corporation Finance (the "Division") has issued [C&DIs](#) of the FAST Act.

Interim Financial Statements

In one C&DI, the SEC staff addresses a key provision of the FAST Act that simplifies the disclosure requirements for EGCs. Under the FAST Act, an EGC may, for historical periods required by Regulation S-X, omit financial information from registration statements on Form S-1 or Form F-1 filed before an IPO (or confidentially submitted to the SEC for review) if the EGC reasonably believes that these historical periods will not be required to be included at the time of the contemplated offering. The SEC staff clarifies that interim financial information, including financial information for the comparative prior period, "relates" to both the interim period and a component of any longer period (interim or annual) in which it will be ultimately included. Thus, interim financial statements would be required in each filing of a registration statement, since any such periods will ultimately be included in either year-to-date interim periods or the annual periods presented in the registration statement as of the effective date.

The C&DI includes an example of a calendar-year-end EGC that submits or files a registration statement in December 2015 and reasonably expects to commence its offering in April 2016 when annual financial statements for 2015 and 2014 will be required. The C&DI states that in such a case, an EGC may not omit its nine-month 2014 and 2015 interim financial statements "because those statements include financial information that relates to annual financial statements that will be required at the time of the offering in April 2016."

Financial Statements of Other Entities

Another C&DI discusses financial statements of other entities (e.g., an acquired business under Regulation S-X, Rule 3-05) within the registration statement. It indicates that an EGC issuer may omit such financial statements from its filing or submission if the issuer reasonably believes that those financial statements will not be required at the time of the offering.

The SEC staff explains that "this situation could occur when an issuer updates its registration statement to include its 2015 annual financial statements prior to the offering and, after that update, the acquired business has been part of the issuer's financial statements for a sufficient amount of time to obviate the need for separate financial statements." The C&DI also includes a reference to paragraph 2030.4 of the Division's [Financial Reporting Manual](#).

International Financial Reporting Standards

The SEC's consideration of the potential incorporation of IFRSs into the U.S. financial reporting system has long been a topic of discussion at various conferences, including the annual AICPA Conference on Current SEC and PCAOB Developments (the "AICPA Conference"), and 2014 and 2015 were no exception. At the 2014 AICPA Conference, SEC Chief Accountant James Schnurr introduced a potential fourth alternative² regarding the use of IFRSs in the United States that would allow

² Before Mr. Schnurr's 2014 speech, alternatives under consideration by the SEC regarding the use of IFRSs in the United States included (1) adopting IFRSs outright, (2) giving U.S. registrants the option of filing IFRS financial statements, and (3) using the so-called "condorsement" approach.

U.S.-based filers to voluntarily provide supplemental IFRS-based information without reconciliation to U.S. GAAP. In his remarks before the 2015 AICPA Conference, Mr. Schnurr indicated that the SEC's Office of the Chief Accountant is likely to recommend that the SEC consider and commence rulemaking that is consistent with this fourth alternative.

Further, in their respective remarks at the 2015 AICPA Conference, both SEC Chair Mary Jo White and Mr. Schnurr reemphasized the importance of continued FASB and IASB collaboration on standard-setting projects in an effort to improve the quality of financial reporting. These comments were echoed by IASB Chairman Hans Hoogervorst, who, in a call for renewed commitment to ongoing collaboration and convergence, asked participants to "stay engaged [with the IASB] and help us in continuing to build our Standards in the future."

Other SEC Matters

Organizational Changes to SEC's Division of Corporation Finance

During 2015, the SEC's Division of Corporation Finance (the "Division"), which contains various assistant director (AD) offices with specialized industry expertise, made a number of organizational changes. The Division merged two of its AD offices responsible for small and large financial institutions into one AD office for financial services. In addition, the Division changed the responsibilities of the associate chief accountants in its Office of the Chief Accountant (CF-OCA); as a result, those individuals are now each responsible for specific topics rather than certain AD offices and industries so that they can develop more subject-matter expertise. The reorganization will also make the CF-OCA's organizational structure more consistent with that of the OCA.

SEC's Request for Comment on Regulation S-X

On September 25, 2015, the SEC issued a [request for comment](#) (RFC) on registrants' views about the financial disclosure requirements under Regulation S-X for certain entities other than the registrant. The RFC asked for feedback about the financial statement and disclosure requirements for (1) businesses acquired or to be acquired under Rules 3-05, (2) subsidiaries not consolidated and 50 percent or less owned persons under Rule 3-09, (3) guarantors and issuers of guaranteed securities registered or being registered under Rule 3-10, and (4) affiliates whose securities collateralize an issue registered or being registered under Rule 3-16.

The SEC indicated that it was interested in hearing feedback from stakeholders about how they currently use the information disclosed under the existing rules and whether they find such information useful for making investment and voting decisions. In addition, the RFC asked whether the required information is presented at the right time and in the optimal manner to be useful. Further, the SEC had indicated that it also wants to know whether there is additional information that investors would find more useful for their decision making.

The public comment period closed on November 30, 2015, and the SEC staff is currently assessing the feedback received.

Thinking It Through

In recent speeches, SEC Chair Mary Jo White Chair indicated that the SEC next expects to address Regulation S-K and certain industry guides. Although Chair White did not touch on specifics in her remarks, aspects of Regulation S-K that might be examined include whether all of the required disclosures related to a registrant's business and operations remain relevant in the current business environment. We expect that in the near term, the SEC will issue a request for comment on Regulation S-K similar to its request for comment on Regulation S-X.

Financial Reporting Manual Updates

During 2015, the SEC's Division of Corporation Finance issued the following updates to its [Financial Reporting Manual](#):

- *January 12, 2015, updates* — The changes were made in light of the FASB's November 2014 issuance of ASU 2014-17 on pushdown accounting and the related rescission of SAB Topic 5.J. The SEC staff rescinded SAB Topic 5.J on November 18, 2014.
- *August 25, 2015, updates* — The changes updated paragraphs 1320.3 and 1320.4 to clarify that “[g]enerally, the Division of Corporation Finance will not issue comments asking a delinquent registrant to file separately all of its delinquent filings if the registrant files a comprehensive annual report on Form 10-K that includes all material information that would have been included in those filings.” Previously, registrants would have sought such an accommodation in writing from the Division's Office of the Chief Accountant. The updates also reiterated that a registrant's filing of a comprehensive annual report on Form 10-K in those circumstances does not (1) absolve the registrant of any Exchange Act liability arising from its failure to file all required reports or shield it from any related enforcement actions; (2) make the registrant “current” for Regulation S, Rule 144, or Form S-8 filings; or (3) affect the registrant's inability to use Form S-3 until the timely-filer requirements are satisfied.

CAQ SEC Regulations Committee Meeting Highlights

The CAQ SEC Regulations Committee and SEC staff periodically meet to discuss various technical accounting and reporting matters, including current financial reporting matters and current practice issues. Highlights of the committee's [March 31, 2015](#), and [June 18, 2015](#), joint meetings with the SEC staff are available on the CAQ's Web site.

SEC Publishes Examination Priorities for 2015

On January 13, 2015, the SEC's Office of Compliance Inspections and Examinations (OCIE) published its [examination priorities](#) for 2015. As explained in an SEC [press release](#), the priorities focus on “protecting retail investors, especially those saving for or in retirement; assessing market-wide risks; and using data analytics to identify signs of potential illegal activity.” The document is not necessarily comprehensive and “may be adjusted in light of market conditions, industry developments, and ongoing risk assessment activities.”

Cybersecurity

On February 3, 2015, the SEC's OCIE issued a [cybersecurity risk alert](#). The risk alert summarizes the findings associated with an examination of over 100 investment advisers and broker-dealers conducted by the OCIE. The OCIE observed the entities' practices related to “identifying risks related to cybersecurity; establishing cybersecurity governance, including policies, procedures, and oversight processes; protecting firm networks and information; identifying and addressing risks associated with remote access to client information and funds transfer requests; identifying and addressing risks associated with vendors and other third parties; and detecting unauthorized activity.” While the risk alert was issued to highlight considerations for registrants in the financial services industry, it is also relevant to the P&U sector.

Effects of Declines in Oil and Gas Prices

During 2015, the SEC staff continuously reminded registrants of the need to consider the effects of the decline in oil and gas prices on their results of operations, liquidity, and financial condition. Under Regulation S-K, Item 303, a registrant must disclose in MD&A any known trends or uncertainties that have had, or that are reasonably expected to have, a material impact on its results of operations (whether favorably or unfavorably). The SEC staff stressed the importance of a registrant's MD&A disclosure of the decline in the prices of crude oil, gas, and other commodities (e.g., iron, copper) if the decline materially affects, or is expected to affect, the registrant's operations.

See Deloitte's December 15, 2015, [Heads Up](#) on the 2015 AICPA Conference and its March 11, 2015, [journal entry](#) for more information.

Communications to XBRL Filers

On December 30, 2014, the SEC announced its launch of a pilot program to help investors analyze and compare financial statement data submitted to the SEC by public companies. The data will be organized into structured sets of information from the companies' XBRL exhibits in SEC filings and will be downloadable from the Commission's Web site.

On March 9, 2015, the SEC staff announced an upgrade to its EDGAR system to support the 2015 U.S. GAAP financial reporting XBRL taxonomy. As noted on the [SEC's Web site](#), the SEC staff "strongly encourages companies to use the most recent version of the US GAAP taxonomy release for their Interactive Data submissions to take advantage of the most up to date tags related to new accounting standards and other improvements."

See Deloitte's March 10, 2015, [journal entry](#) for more information.

Updates to EDGAR Filer Manual and Technical Specifications

On June 18, 2015, the SEC issued a [final rule](#) to implement Release 15.2 of its EDGAR system filer manual. The release updates Volume II of EDGAR as well as several XML technical specifications, including those related to EDGARLink Online and EDGAR ABS. Specific updates include:

- New and updated submission form types.
- Removal of OMB expiration dates from certain submission forms.
- Removal of support for US-GAAP-2013 and EXCH-2013 taxonomies.

The final rule became effective on June 29, 2015.

SEC Issues Concept Release on Audit Committee Disclosures

On July 1, 2015, the SEC issued a [concept release](#) requesting feedback on potential enhancements to the audit committee disclosure requirements. In particular, the Commission sought to learn more about the factors the audit committee considers when overseeing the independent auditor. Regarding the need for an ongoing assessment of these requirements, Chair White pointed out that "[t]he way audit committees exercise their oversight of independent auditors has evolved and it is important to evaluate whether investors have the information they need to make informed decisions." Comments on the concept release were due by September 8, 2015.

See Deloitte's July 15, 2015, [Heads Up](#) for additional information.

SEC and Other Organizations Publish Joint Staff Report on U.S. Treasury Market

On July 13, 2015, staffs of the SEC and four other agencies released a [joint staff report](#) that analyzes what the staffs' related joint [press release](#) describes as "the significant volatility in the U.S. Treasury market on October 15, 2014." As stated in the press release, the report notes that the volatility included "an unusually rapid round trip in prices and deterioration in liquidity during a narrow window" and concludes that it was caused by a number of factors, such as "changes in global risk sentiment and investor positions, a decline in order book depth, and changes in order flow and liquidity provision."

SEC Staff Comments

The focus of recent SEC staff comments to registrants in the P&U industry is largely consistent with that of staff comments issued in past years. Specifically, the staff has concentrated on (1) dividend restrictions; (2) accounting for the impact of ratemaking; (3) regulatory disallowance of property, plant, and equipment; and (4) identification of possible phase-in plans.

The SEC staff has also issued comments related to whether registrants in the P&U industry have complied with requirements under ASC 450 to disclose their range of loss in connection with litigation and other contingencies. Further, the staff has asked such registrants to explain the considerations they gave to separately disclosing the revenues and costs of revenues related to nonregulated businesses in light of Regulation S-X, Rule 5-03(b)(1) and (2). For additional considerations related to these topics, refer to the Contingencies and Financial Statement Classification, Including Other Comprehensive Income sections in Deloitte’s *SEC Comment Letters — Including Industry Insights: What “Edgar” Told Us*.

Dividend Restrictions

Example of an SEC Comment

Reference is made to your disclosure . . . of [Company A’s] maximum ratio of consolidated financial indebtedness to consolidated total capitalization imposed by a credit agreement. Please tell us whether this covenant, other financial covenants and/or restrictions imposed by regulatory commissions restrict the ability of your subsidiaries or investments accounted for by the equity method to transfer funds to you in the form of loans, advances or cash dividends. If so, please tell us: (i) the amount of restricted net assets of consolidated subsidiaries and your equity in the undistributed earnings of investments accounted for by the equity method as of September 30, 2014 and how you computed the amount; (ii) your consideration of providing the disclosures required by Rule 4-08(e)(3)(i) and (ii) of Regulation S-X; and (iii) your consideration of providing the condensed financial information prescribed by Rule 12-04 of Regulation S-X in accordance with Rule 5-04 of Regulation S-X.

Given the nature of regulation in the P&U industry, there may be constraints on a P&U registrant’s financial flexibility and its relationships with affiliated parties, including the parent company. For example, a utility subsidiary may be subject to requirements imposed by federal and state regulators that establish a minimum equity capitalization ratio or set limits on the payment of dividends. In addition, the capital-intensive demands of the P&U industry require significant financing agreements at the subsidiary level that may restrict (1) a subsidiary’s transfer of assets in the form of advances, loans, or dividends to the parent company or another affiliated party or (2) other types of transactions between a subsidiary and its affiliates. The inability of a subsidiary to transfer assets to the parent company could, in turn, restrict the parent company’s ability to pay dividends to its own shareholders.

Consequently, several P&U registrants have received comments from the SEC staff about their compliance with Regulation S-X, Rules 4-08(e) and 5-04. Those comments have included inquiries about whether consideration was given to regulatory or other limitations (i.e., debt agreements) that could restrict the transfer of assets from a subsidiary to the parent company through dividends, loans, advances, or returns of capital. As a result of the staff’s comments, several P&U registrants have been required, or have agreed, to prospectively (1) expand their notes to the financial statements about potential dividend restrictions in accordance with Rule 4-08(e) and (2) include a Schedule I in their annual Form 10-K filing in accordance with Rule 5-04. Registrants should be aware that the calculations for determining the note disclosures required under Rule 4-08(e) should be performed independently of the calculations for determining the required Schedule I disclosures, and that compliance with one set of disclosure requirements does not satisfy the requirements of the other.

For additional considerations about dividend restrictions, see the Debt section in Deloitte’s *SEC Comment Letters — Including Industry Insights: What “Edgar” Told Us*.

Accounting for the Impact of Ratemaking

Example of an SEC Comment

We noted a significant increase in your regulatory asset related to [Matter X] during the fiscal year ended December 31, 2014. . . . We also note your disclosure . . . that the [state legislation] leaves the decision on cost recovery determinations related to [Matter Y] to the normal ratemaking processes before utility regulatory commissions and your disclosure . . . that you believe recovery is probable. We further note your disclosure in multiple instances . . . that an order from the regulatory authorities disallowing recovery of costs related to [Matter Z] could have an adverse impact on your financial statements. As it appears you do not have a regulatory order supporting the deferral of these costs, please tell us why you believe the amounts you have deferred as regulatory assets are probable of recovery under U.S. GAAP and provide us with your detailed analysis supporting this conclusion including both positive and negative evidence you considered. Refer to ASC 980-340-25-1.

The above example is indicative of the SEC staff's focus on ensuring that P&U registrants are thoughtful in determining the initial and continuing probability of cost recovery inclusive of the expected recovery period. Further, the SEC staff continues to issue comments on (1) providing supplemental explanations or separate detailed analysis and evidence that support the P&U registrant's recognition of regulatory assets, (2) how the P&U registrant's current regulated rates are designed to recover its specific costs of providing service, (3) the nature of the P&U registrant's material regulatory assets and liabilities, (4) whether a particular regulatory asset of the P&U registrant is earning a rate of return, and (5) the P&U registrant's accounting policies for revenues subject to refund. Over the past year, the SEC staff has focused particularly on items (1) and (4).

Regulatory Disallowance of Property, Plant, and Equipment

Example of an SEC Comment

We note from your Form 8-K filed on March 9, 2015 that [Utility Commission A] voted to disallow recovery of costs related to [Capital Project A] and that you expect to record a charge of approximately \$[X] during the first quarter of 2015. Considering the recovery disallowance recommendations of [Intervenor A] and [Intervenor B] during 2014 along with the February 2015 [administrative law judge] recovery disallowance proposal, please tell us in more detail why no charges were recorded during fiscal 2014 related to the [Capital Project A] prudence investigation.

SEC staff comments to public utility registrants continue to focus on the guidance in ASC 980-360-35 on subsequent measurement and recognition of property, plant, and equipment related to regulated operations. Under that guidance, an entity should record a disallowance related to a recently completed plant if it determines that a disallowed amount is probable and reasonably estimable; the entity must use judgment to make that determination. In light of recent regulatory orders by state public utility commissions that limit a public utility entity's cost recovery, registrants have been asked to explain their considerations related to the timing of recording a disallowance, particularly when a disallowance was not recorded until a rate order was received.

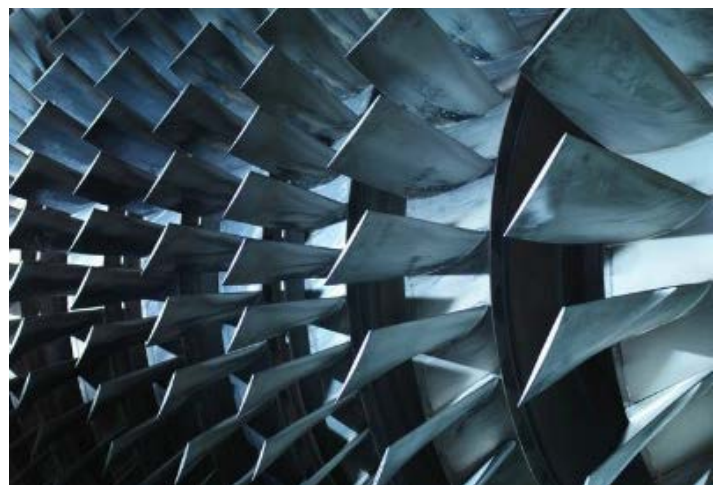
Identification of Possible Phase-In Plans

Example of an SEC Comment

Please explain to us in detail why the method of recognition of allowable costs in rates associated with bare steel and cast iron replacement activities of [Subsidiary A] and [Subsidiary B], the capital infrastructure program of [Subsidiary A,] and [the replacement of] bare steel and cast iron pipelines and other infrastructure by [Subsidiary C] are not considered phase-in plans as defined in ASC 980-340-20.

To lessen the impact of a rate increase as part of a current rate proceeding, a regulator may decide to defer costs associated with a major new plant addition. A deferral of any costs associated with a major, newly completed plant could be a phase-in plan. In accordance with ASC 980-340-25-2, cost deferrals are not permitted for phase-in plans. To qualify as a phase-in plan, a method for recognizing allowable costs must meet the three criteria outlined in ASC 980-340-20.

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



Section 3
Industry Accounting
Hot Topics

Depreciation Adjustments

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

“Mirror Depreciation”

If a utility records accelerated or additional depreciation in the interest of accelerating asset recovery and subsequently determines that the excess depreciation reserves are no longer necessary, such an action is referred to as “mirror depreciation” because of its similarity to the mirror 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 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 U.S. GAAP restrictions that would prohibit the reversal of a previously recorded and collected accumulated cost of removal. The regulator imposed the liability, and the regulator can eliminate or reduce the liability. Accordingly, a negative cost of removal amortization 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 U.S. GAAP depreciation, reversals of previously recorded excess reserves related to “mirror depreciation” are permitted. As a result, adjustments of depreciation expense to address theoretical excess depreciation reserves (excluding any cost of removal) should not cause net depreciation expense to be less than zero for any class of assets, as defined by the applicable depreciation study for any particular period. This would permit the assumed depreciable life of a class of assets to be as low as zero for a period until the theoretical excess is eliminated, but it would not result in the actual reversal of previously recorded depreciation expense.

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 to adjust excess depreciation reserves 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 impact 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 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 impact of regulatory lag, a utility must use significant judgment and evaluate the specific facts and circumstances.

Normal Purchases and Normal Sales (NPNS) Scope Exception

In accordance with ASC 815-10-15-35, for a “contract that meets the net settlement provisions of [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. If a contract designated as NPNS is restructured, that restructuring may indicate a net settlement of the original contract and execution of a new contract, potentially calling into question whether the original contract resulted in physical delivery throughout the original term of the contract and whether similar contracts (e.g., the newly executed contract) are expected to result in physical delivery throughout their term. Entities should carefully evaluate each contract restructuring to determine whether the original contract was simply amended or whether there is effectively a termination of the old contract and 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 recent years, a reduction in demand for coal-fired baseload generation has resulted in an increase in coal inventories for companies with significant coal-fired generation. In certain instances, entities have negotiated new coal contracts to provide for volumetric optionality. Decreases in demand or the need for flexibility may affect the accounting for long-term coal contracts and could be driven by factors such as:

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

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

Application of the NPNS Scope Exception to Certain Electricity Forward Contracts in Nodal Energy Markets (ASU 2015-13)

Background and Inquiry

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

ASU 2015-13

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.

¹ A power purchase or sales agreement that is a capacity contract may qualify for the NPNS election under ASC 815-10-15-45 through 15-51.

ASU 2015-13 was effective upon issuance and must be applied prospectively. In the period of adoption, entities 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.

Impact of Subsequent Events Related to Regulatory Matters

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

ASC 855 prescribes the accounting for events and transactions that occur after the balance sheet date but before entities issue financial statements. Under ASC 855, there are two types of subsequent events. Type 1 subsequent events provide additional evidence about conditions that existed as of the balance sheet date, including estimates inherent in the preparation of financial statements. Type 1 subsequent events are recognized in the financial statements. Type 2 subsequent events provide evidence about conditions that did not exist as of the balance sheet date but arose after that date. Although Type 2 subsequent events are not recognized in the financial statements, material Type 2 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 Type 1 subsequent event because the event that gave rise to the contingency occurred before the balance sheet date. The resolution, which may have been in the form of a court or regulatory order, a settlement agreement, or something similar, is a subsequent event that provides additional evidence about the probability and amount of the loss and should be reflected in the financial statements.

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

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

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

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

Considerations for Regulated Utilities

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

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

Subsequent-Event Examples

Fuel Order Issued After the Balance Sheet Date

On July 15, 2015, Utility A's regulator issued an order with respect to a routine review of Utility A's fuel clause adjustment calculation for the period from January 1, 2014, to December 31, 2014. Utility A had not yet issued its June 30 financial statements. In this order, the regulator ruled that Utility A should have credited certain wholesale sale margins to its retail fuel clause. The order required Utility A to refund \$5 million. Utility A was aware that intervenors were questioning this item on the basis of testimony that had been filed a few months earlier but had expected to prevail in this matter, which represented a loss contingency as of June 30. The July 15 order was a Type 1 subsequent event that provided additional information about the probability and amount of the loss as of June 30. Therefore, Utility A accounted for the effect of this order in its financial statements as of and for the period ended June 30, 2015, and included the disclosures prescribed by ASC 980-605.



Interim Rates Implemented — Final Rate Order Received

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

Appeal of Prior Unfavorable Rate Order

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

Rate Order After the Balance Sheet Date — Order Includes a Disallowance

In conjunction with its ruling on a rate case, Utility D's regulator concluded that there was significant management error in the planning and construction of a recently completed power plant. In the order issued after the balance sheet date but before the financial statements had been issued, the regulator required that plant costs in excess of a specified amount not be recovered in rates. The recovery of this plant was a key issue throughout the proceedings and the primary basis for the request for an increase in rates. Before the issuance of the rate order, Utility D had concluded that the likelihood of a disallowance was reasonably possible but less than probable.² Utility D concluded that the post-balance-sheet ruling constituted additional significant objective evidence about the likelihood of disallowance as of the balance sheet date. Accordingly, Utility D updated its assessment of the probability of a disallowance as a result of this Type 1 subsequent event and recorded a charge to earnings in the current period. Post-balance-sheet events other than a final order from a regulator may also constitute significant objective evidence about conditions that exist as of the balance sheet date.

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

In a prior period, in conjunction with an order from its regulator, Utility E's regulator required that Utility 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, Utility 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 concluded that Utility E did not need to refund the difference. Utility E concluded that the post-balance-sheet order represented a Type 2 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 Utility 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, in part, 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, in part, 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 Utility 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 Utility E's determination that the rate order was a Type 2 subsequent event.

² 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.

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 Utility 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 Utility F had with the staff of the regulatory commission, Utility 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 Type 2 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. The company had requested continued amortization of these costs in its current rate proceeding. As of the balance sheet date, no testimony had been filed that had questioned the continued recovery of the storm damage costs, and Utility G concluded that future recovery of its regulatory asset balance was probable.

In connection with its current rate proceeding, shortly after year-end, Utility G commenced settlement discussions. Intervenors indicated that they were willing to settle the case if Utility G would forgo the remaining amortization of the storm damage costs. While Utility G strongly disagreed with the intervenors' position on storm damage costs, in the context of the overall settlement proposal, Utility 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., Utility 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 Utility G was expecting. Shortly before the financial statements were issued, the parties agreed to the settlement. On the basis of precedent, Utility G believed it was probable that its regulator would approve the settlement. Utility G concluded that this settlement represented a Type 2 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.

Companies need to exercise judgment when there are surprise developments. For example, had there been any discussions with intervenors before the balance sheet date about the potential to forgo recovery of the deferred costs, or had testimony been filed advocating no further recovery, questions would have been raised as of the balance sheet date about the

probability of recovery and the settlement may have indicated a Type 1 subsequent event. In most cases in which a rate order issued after year-end contains an unexpected ruling affecting a regulatory asset as of the balance sheet date, such a rate order is considered a Type 1 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 prudence review in the current regulatory process.

Plant Abandonments and Disallowances of the Costs of Recently Completed Plants

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

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

Matters Related to Abandonment Accounting

The discussion above describes the overall accounting model for asset abandonments in a regulated environment; however, utilities should carefully assess facts and circumstances to determine what constitutes abandonment of an asset and the likelihood that abandonment will occur. While ASC 980-360 provides no explicit guidance on what constitutes an abandonment of an operating asset, an asset that will be retired in the near future and much earlier than its previously expected retirement date typically is subject to the ASC 980-360 disallowance test. Alternatively, if an asset is to be retired, but not in the “near future” 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 entities to consider in evaluating whether a plant is being abandoned include the following:

- A change in remaining depreciable life of the operating asset outside the utility’s normal depreciation study.
- Any accelerated depreciation because of a change in depreciable life that is not currently reflected in rates or expected to be reflected in rates in the near future.

- A retirement of the asset sooner than its remaining useful life and in the near future.
- A reduction in the estimated remaining depreciable life by more than 50 percent.

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

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

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

Reconsideration of Abandonment Decision

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

Disallowances of Costs of Recently Completed Plants

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

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

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 effectively been defined on the basis of facts and circumstances, so some diversity has resulted. The starting point for determining what constitutes a recently completed plant or a major, newly completed plant is typically the time from the completion-in-service date until the plant owner files its initial rate request for inclusion of the plant in allowable costs. In addition, if an unregulated affiliate transfers a recently completed plant to the rate-regulated utility, impairment 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. Unlike the phase-in plan guidance in ASC 980-340, which refers to "major" in connection with "newly completed plant," the disallowance guidance in ASC 980-360 refers to "recently completed plant" and does not introduce the concept of "major." As a result, in the

evaluation of potential disallowances, the guidance in ASC 980-360 applies to all recently completed additions to PP&E, not just “major” new additions.

Indirect Disallowances

ASC 980-360 also addresses explicit, but indirect, disallowances that occur when no return or a reduced return is permitted for all or a portion of the new plant. In the case of an indirect disallowance, if the regulator does not specify the amount of the disallowance, the amount must be calculated on the basis of estimated future cash flows. To determine the loss resulting from an indirect disallowance, entities should estimate and discount the future revenue stream/cash flows allowed by the regulator by using a rate consistent with that used to estimate the future cash flows. This amount should be compared with the recorded plant amount, and the difference should be recorded as a loss. Under this discounting approach, the remaining asset should be depreciated in a manner consistent with the 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.

Considerations for Disallowances Outside the Scope of ASC 980-360

Disallowances of costs for plants that are not recently completed are recognized in accordance with general U.S. GAAP. For example, assume that (1) a company puts a new plant into service and then goes through a rate case when the prudence of the costs 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. Further, assume that the plant costs are questioned a few years later in the next rate case and that the regulator disallows a specific amount of the plant cost. A disallowance charge based on ASC 980-360 should not be recorded because that plant is no longer a recently completed plant. Rather, an entity should apply the impairment criteria in ASC 360 when evaluating disallowances of plant costs for PP&E that is not recently completed. Refer to [Impairment Considerations](#) for more details.

Accounting for Renewable Energy Certificates

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

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



Lease Accounting

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

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

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

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

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

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

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

Another acceptable view is that RECs may be considered outputs because they (1) result directly from a facility’s production process and (2) represent discrete marketable elements.⁴ Proponents of this view believe that it is not necessary for outputs to be “tangible” as long as they are generated as a result of the operations of the PP&E and represent discrete elements that could be sold to other entities or other market participants. Such proponents also note that because RECs can significantly affect the underlying value of the PP&E, they are an important consideration in the evaluation of whether the right to use the renewable energy generation facility has been conveyed to the purchaser. They should therefore also be considered in the determination of whether parties other than the purchaser are taking more than a minor amount of the output or other utility that will be produced or generated by the PP&E.

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

³ The guidance in ASC 840 applies to both sellers and purchasers; therefore, this evaluation should be performed by each party to the contract and both parties would be expected to reach the same conclusion about the presence of a lease.

⁴ Economic attributes are generally not considered outputs in the determination of whether an arrangement contains a lease unless they are both (1) generated by the facility’s production process and (2) separately marketable. For example, although PTCs are linked to a renewable facility’s production levels, they are not considered outputs because they can only be conveyed through an ownership interest and therefore are not separately marketable.

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

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

Derivative Considerations

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

RPSs in several states have resulted in secondary markets for REC exchanges (e.g., the [Green Exchange](#)). Because such markets are still evolving, the assessment of the “net settlement” criterion (more specifically, whether the RECs are readily convertible to cash) can be challenging and may require entities to use significant judgment. One consideration is whether an active spot market exists for the REC itself, and the determination may vary depending on state or region.

Because entities continually evaluate contracts to buy or sell RECs over their lives, contracts that did not previously qualify as derivatives may later meet the definition. Therefore, as REC markets develop, entities should consider use of the “conditional” NPNS designation to reduce the risk of potential effects on the financial statements.⁵

In addition, in some contracts, RECs may be combined with the purchase or sale of energy; energy is generally considered RCC. See [Section 4](#) for additional discussion of derivatives in arrangements with multiple deliverables.

Asset Type and Accounting Value

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

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

Asset Type

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

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

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

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

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

Accounting Value

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

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

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

Incremental Cost

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

Joint Product Allocation

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

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

By-Product Allocation

In some circumstances, RECs may be considered a by-product of electricity generation. In other cases (e.g., if RPSs may exist in a state without an abundance of renewable generation), RECs may be the primary product developed by the renewable facility, with electricity considered a by-product. Under the by-product method, the by-product would be assigned cost at its fair value, with the residual amount recorded as the cost basis for the principal product.

Depending on the principal product and by-product designations, this method could result in faster or slower cost recognition than the previous two methods.

Accounting Value Summary

Which of the three methods an entity uses to determine the accounting value of internally generated RECs will depend on the applicable facts and circumstances, including the unique environment in each jurisdiction. Irrespective of the accounting method used to determine the original accounting basis, entities should apply the appropriate ongoing accounting and impairment models to their REC asset types. For example, REC assets should generally be expensed as they are used or sold to third parties and are subject to considerations related to (1) LCM inventory valuation or (2) amortized intangible impairment.

REC Shortfall Considerations

In certain states with RPSs, electricity suppliers may be required to purchase RECs when there is a REC shortfall below the required level for the compliance period (e.g., the entity did not generate enough electricity at qualifying facilities to meet its own compliance requirements). Shortfalls of RECs represent obligations that should be recorded as liabilities; however, the timing of liability recognition differs in practice. Some support recognition of a liability only when the entity's RECs have been exhausted, while others believe that consideration related to expected shortfalls should be recognized throughout the compliance period in accordance with ASC 270. Because of the evolving nature of RPSs and the diversity in accounting views, companies should consider discussing the accounting for expected shortfalls with their auditors. For discussion of the new revenue model's implications for RECs, see [Section 6](#).

Rate-Case Settlements

A utility company periodically files a rate case with its regulatory commission. This may be due to the commission's requirements that the utility company file a new rate case or because the utility company has chosen to request new rates. When fully litigated in front of the regulatory commission, the rate-case process is often long, sometimes lasting more than a year from the date the utility company initially files its rate-case request to the date the regulatory commission approves the request. The rate-case process involves data requests from the commission staff and intervenors to the rate case as well as multiple rounds of testimony and hearings.

However, in many regulatory jurisdictions, the utility company and the intervenors will hold settlement discussions. The goal of the settlement discussions is for the utility company and the intervenors to agree to the significant terms of the rate case. The settlement is filed with the regulatory commission in the form of a settlement agreement that the regulatory commission can then review and approve or reject. The advantage of a settlement agreement is that it reduces the period before new rates can be established because hearings and testimony are not required. A settlement agreement may settle all aspects of a rate case, or it may refer a portion of the rate case (e.g., recovery of a specific cost) back to the regulator.

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

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

- A utility company should consider preparing a calculation of the hypothetical settled revenue requirement on the basis of the initially filed rate case, filed testimony and responses to intervenor requests, discussions with intervenors and the regulator, and the settlement agreement. This detailed calculation, which is based on the agreed-to revenue requirement, may help the utility company understand the components (e.g., those related to rate base, cost of service, and return on rate base) of the settled revenue requirement and the accounting implications of the settlement. To perform this calculation, the utility company may need input from various departments at the company, including regulatory, accounting, and legal, and will need to use significant judgment depending on the level of detail in the settlement agreement. The calculation of the hypothetical settled revenue requirement should be sufficiently detailed for parties to understand the significant judgments and the allocations made.
- Specific considerations may include (1) the estimated capital structure ratio and cost of capital components, (2) a determination of how previously deferred costs will be recognized for both the amount of costs and the duration of recovery, and (3) whether any regulatory assets should be written off because they are no longer collectible.

The judgments about the capital structure ratio and cost of capital components will affect the amount of allowance for funds used during construction (debt and equity) that are capitalized to utility plant for the periods after the rate-case settlement is approved. The judgments regarding the regulatory assets may be significant for both the current period (deferral of costs incurred or a write-off of costs previously incurred) and 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, such as significant changes in the regulatory environment or losses of major customers, indicate that the carrying amount of an asset or asset group may not be recoverable, the utility should review its assets for impairment.

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.

Master Limited Partnerships and Yieldcos

MLPs and yieldcos are financing vehicles that can lower the cost of capital for P&U companies without requiring the P&U companies to give up the benefit of control of assets transferred to the MLPs and yieldcos.

MLPs are publicly traded partnerships that allow investors to purchase units on a securities exchange similarly to how they purchase common stock. Because MLPs are classified as partnerships, they do not pay corporate tax and avoid double taxation on dividends. Income from the MLP flows through to the partners and is taxed at the partners' individual tax rate. The established legislation for MLP structures, IRC Section 7704, requires that 90 percent of the revenue from the partnership be derived from activities related to natural resources, commodities, or real estate. Typically, midstream assets (e.g., gas transmission and storage facilities) meet the requirements for qualifying income.

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

Yieldcos are publicly traded companies that also pay periodic cash distributions to investors. One advantage of yieldcos is that they do not have to meet the qualifying income requirements of IRC Section 7704. Yieldcos typically include capital-intensive renewable energy assets underpinned by long-term power purchase agreements that support stable and predictable cash flows. Although these financing vehicles generally take the legal structure of a corporation, much of their income is shielded by net operating losses, carryforwards, and significant amounts of depreciation. On an after-tax basis, yieldcos and MLPs offer very similar tax advantages to investors. One important distinction is that whereas MLP income is permanently exempt from federal income taxes at the partnership level if the requirements of IRS Section 7704 are met, yieldcos' tax shields are limited to the amount of net operating losses and carryforwards attributable to the entity (i.e., to shield income for 5–10 years). However, yieldcos have the ability to extend the tax shield by acquiring new assets after their IPO.

Yieldco structures will generally include a public corporation with two classes of equity. The public will generally be offered Class A shares that offer the ability to participate in distribution with limited, if any, voting interest. The sponsor will generally retain Class B shares that offer the majority voting interests as well as the right to participate in distributions, albeit generally in a lesser capacity.

Industry Considerations

Many P&U companies are further exploring MLPs and yieldcos since these financing vehicles have become useful for lowering the cost of capital. MLPs and yieldcos need stable cash flows to consistently fund the periodic cash distributions. To increase the amount of cash available for distribution, these financing vehicles need to grow their asset base

continuously. P&U companies that opt for an MLP or yieldco structure will most likely hold back certain assets to drop into the MLP or yieldco after the public offering.

Accounting Considerations

Predecessor Entity

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

Carve-Out Financial Statements

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

See the [Carve-Out Financial Statements](#) subsection for discussion of other relevant accounting and reporting considerations.

Consolidation Accounting

P&U companies need to evaluate affiliated MLPs and yieldcos for consolidation under (1) the current consolidation guidance in ASC 810 and (2) [ASU 2015-02](#), which is effective for public business entities for fiscal years, and for interim periods within those fiscal years, beginning after December 15, 2015. Refer to the [Accounting Standards Codification Update](#) section for more information on ASU 2015-02.

As noted above, most MLPs use an LP/GP structure. ASU 2015-02 provides for a rebuttable presumption that a partnership would be considered a variable interest entity (VIE) in the absence of substantial LP kick-out rights. If an MLP is considered a VIE, an evaluation would be required to determine whether the P&U parent is the primary beneficiary.

In addition, yieldcos may alter the structure of their assets as part of the offering, or subsequently, by creating a tax/equity structure. This type of structure separates the tax and cash attributes of the renewable assets for multiple owners through a variety of forms, including partnership flip structures, sale-leaseback structures, and inverted lease structures. Tax/equity structures can be very complex and require particular attention to determine the appropriate consolidation requirements for the entity.

Materiality

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

Further, in light of a lower materiality threshold, P&U companies may need to revisit the design of ICFR related to the accounting records of the new business. In addition to making existing controls more precise, P&U companies may need to create additional internal controls to mitigate risks related to new disclosures or technical accounting topics that were not previously material.

Additional Financial Statements

In situations in which the predecessor entity has recently acquired a significant business or has significant equity method investments, additional audited financial statements may need to be included in the registration statement. Under Regulation S-X, Rule 3-05, registrants must perform the asset test, investment test, and income test to measure the significance of any recently acquired businesses. Registrants must also perform the investment test and the income test (the asset test does not apply to equity method investments) to measure the significance of any equity method investments under Regulation S-X, Rule 3-09. As noted previously, interests in tax/equity partnerships are often owned by yieldcos. It may be concluded that certain partnerships should be accounted for as an equity method investment under ASC 323, in which case the project may need to be evaluated for significance under Rule 3-09. The level of significance is used to determine the financial statement periods for which a registrant must include the financial statements of the recently acquired business or equity method investee in the registration statement.

Pro Forma Financial Statements

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

Drop-Down Transactions

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

Real Estate Sale Considerations

Given the nature of the underlying assets involved in MLP and yieldco structures, preparers and auditors should also consider whether real estate sale rules would apply to transfers of assets to those structures. Such rules could apply to initial formation as well as subsequent drop-downs. If real estate sale rules do apply, companies should carefully review all of the governing documents to identify any forms of continuing involvement that may preclude sale accounting. It is likely that those same provisions will also be informative in companies’ determination of the appropriate fail-sale accounting method if sale accounting is indeed prohibited.

Carve-Out Financial Statements

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

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

The term “carve-out financial statements” describes the separate financial statements that are derived from the financial statements of a parent company. The form and content of those financial statements may vary depending on the circumstances of the transaction. For example, if the carve-out financial statements are to be used solely by a small, strategic buyer, an unaudited balance sheet and income statement for the most recent fiscal year may be sufficient. A public buyer, however, may need a full set of SEC-compliant audited financial statements, including related disclosures, for the three most recent fiscal years. Yet another buyer might ask that the periods be audited but may be completely unconcerned with SEC reporting considerations. Accordingly, assessing the needs of potential financial statement users is critical to understanding the level of detail and number of periods to be presented in the carve-out financial statements.

Such an assessment can be challenging when the carve-out financial statements are being prepared before all relevant information is known (e.g., before a method of disposal has been determined, before the buyer has been identified).

Internal Control Considerations

It is important for entities to consider internal control over financial reporting (ICFR) when preparing carve-out financial statements. Key questions for entities to ask about ICFR include:

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

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

Implementing and evaluating ICFR related to carve-out financial statements is critical given the amount of judgment an entity must exercise in preparing these statements. Entities considering the preparation of carve-out financial statements should evaluate ICFR as part of their pre-transaction planning activities and determine whether they need to implement additional control activities, training programs, or financial reporting processes to sufficiently address the risk of material misstatement. Given the nature of carve-out statements (e.g., reliance on several judgments and allocations, incorporation of transactions and events that may have occurred multiple years in the past), many of the control activities an entity implements are likely to be management review controls with a focus on the level of precision of the review and the experience of the individuals responsible for performing the control activity.

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

Judgments and Allocations

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

Allocation methods in the industry are often based on items such as generation capacity, energy generated, headcount, and payroll.

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

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

Tax Considerations

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

Reporting Considerations

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

Discontinued Operations

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

In April, 2014, the FASB issued [ASU 2014-08](#) (codified in ASC 205-20), which changed the criteria for reporting discontinued operations and has reduced the frequency with which disposals qualify for presentation as a discontinued operation.

Business Segment Disclosure

Disposal transactions may have an impact on the parent entity's segment reporting. A disposal of a significant portion of the parent entity's operations could cause a change in management's view of the business or in the parent entity's segments.

Further, in preparation for a disposal, management may seek to realign the business and may legally transfer operations or assets from one segment to another. If segments are restructured, management should consider the guidance in ASC 280-10-50-34, under which an entity is required to retrospectively apply the segment change to earlier accounting periods. In addition, if the carve-out statements will be used in a public filing, the carve-out statements will also need to disclose the segments identified in the formation of the new carve-out entity.

Transactions Between Entities Under Common Control

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

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

SEC Reporting

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

Other Resources

For more information on carve-out financial statements, see Deloitte's [A Roadmap to Accounting and Financial Reporting for Carve-Out Transactions](#).

Asset Retirement Obligations

The EPA's Disposal of Coal Combustion Residuals From Electric Utilities Rule (the "CCR Rule") has brought a renewed focus to accounting for AROs for utilities. As a result of the CCR Rule, many utilities were required to record AROs in 2015 for coal ash ponds meeting certain criteria under the CCR Rule. The discussion below focuses on key topics related to the classification, recognition, and derecognition of AROs.

ARO Versus Environmental Remediation

Entities must consider whether the obligation to remediate represents an ARO or an environmental remediation liability. The scope of the guidance in ASC 410-20 on AROs is limited to those obligations that cannot be realistically avoided, assuming that the asset is operated in accordance with its intended use. AROs are related to contamination arising out of "normal" operations that generally is (1) expected or predictable, (2) gradual (or occurring over time), (3) integral to operations, or (4) unavoidable and does not require an immediate response. Environmental remediation is related to contamination arising out of improper use of an asset or a catastrophic event that (1) is generally unexpected, (2) requires immediate

response or reporting, (3) generally could have been controlled or mitigated, and (4) is the result of a failure in equipment or noncompliance with company procedures. This guidance is illustrated in the following examples:

- *Example 1* — An entity that operates a coal power plant with ash ponds has a legal obligation to remediate the ash ponds under the CCR Rule. Because the obligation results from the normal operation of the asset (i.e., the ash is an unavoidable byproduct of operating the coal plant), the obligation should be accounted for as an ARO under the provisions of ASC 410-20.
- *Example 2* — An accident occurs as a result of improper operations, causing a breach in an ash pond that results in the contamination of the area surrounding the site. The entity is required under federal laws to remediate the contamination. Because the obligation to remediate the land around the site results from improper operation of the asset, the obligation should be accounted for as an environmental remediation liability under an ASC 450/ASC 410-30 probability model.

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

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 requires a change in the ARO estimate:

- In preparing the five-year financial forecast, management models asset retirement costs 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 CCR 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 PPGE 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 230-10-45-17 states that cash payments made to settle an ARO should be classified as operating activities.



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 revenue currently:

- 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 may provide for collection over a period that begins before the 24-month collection period and 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.



Section 4

Energy Contracts, Derivative Instruments, and Hedging Activities

This section summarizes current trends and activity in the P&U sector and how they may affect the accounting and reporting for energy contracts.

Market Activity

Coal

In August 2015, President Obama and the EPA announced the CPP, which sets CO₂ emissions performance rates for affected power plants that are to be achieved beginning in 2022. As major CO₂ contributors, coal-fired power plants are viewed as environmentally unfriendly. The CPP will regulate companies and require them to find cleaner energy alternatives. In addition, banks are under increasing pressure to cut ties with coal mining and power projects; as a result, major banks are scaling back coal financing and limiting credit risk to the global coal sector.¹

Amid mounting environmental concerns about coal and companies' continuing search for alternative fuel sources, coal prices in the United States have steadily declined. The spot price for high-grade, low-sulfur Central Appalachian coal decreased by approximately 21 percent, from about \$53 per ton in the third quarter of 2014 to about \$42 per ton in the third quarter of 2015. Forward prices for Central Appalachia for the forward 12-month period decreased by about 26 percent on average from the third quarter of 2014 to the third quarter of 2015. Although the spot price for low-grade, high-sulfur Powder River Basin coal remained relatively unchanged at around \$11 per ton, forward prices for Powder River Basin for the forward 12-month period decreased by roughly 22 percent on average from the third quarter of 2014 to the third quarter of 2015. The decreasing prices have been driven primarily by a decrease in demand for coal. Lower natural gas prices, combined with the increasing regulatory constraints causing power producers to gradually turn their attention from coal to natural-gas-fired generation capacity, has been a significant contributor to the decrease in demand. In fact, in April 2015, natural-gas-fired generation surpassed generation from coal for the first time.²



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

- *Implications for NPNS elections and hedge accounting* — The application of derivative accounting elections (hedge accounting or NPNS) is directly related to certain assertions entities make about their business strategy or operations. Companies will have to continue revisiting their assertions to determine whether the existing accounting elections are still appropriate.
- *Impairment of coal generation assets, coal inventories, or both* — Coal generation may be displaced as the transition to natural gas occurs, which could have implications for the economic useful life of generation assets and related inventories.

Natural Gas

U.S. natural gas prices have decreased rather significantly over the past year despite the transition from coal to natural gas noted above. Henry Hub spot prices have decreased by about 37 percent, from about \$4.02 per MMBtu as of September 30, 2014, to about \$2.52 per MMBtu as of September 30, 2015. Forward prices for the forward 48-month period decreased from the third quarter of 2014 to the third quarter of 2015 by about 29 percent on average. This decrease is driven by substantial increases in supply (supplies are higher than third-quarter 2014 levels as well as the previous five-year average) as a result of improved drilling efficiency and new wells coming online. In fact, natural gas inventory supplies

¹ Source: <http://www.ibtimes.com/morgan-stanley-under-pressure-coal-industry-financing-climate-change-concerns-2135013>.

² Source: <http://www.eia.gov/todayinenergy/detail.cfm?id=22312>.

increased for 34 consecutive weeks during 2015 through the week ended November 20, 2015.³ This further supports the expectation that supply is unlikely to be challenged even if the winter turns out to be worse than forecasted.

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

Electricity

U.S. electricity prices also decreased from September 2014 to September 2015, as reflected in an analysis of prices charged by various RTOs across the country, including PJM Western Hub, ISO-NE Internal Hub, CAISO-SP15, and ERCOT-North Zone. Average spot prices decreased by roughly 23 percent during that period, from about \$43 to about \$33. In addition, forward prices for the forward 36-month period decreased by 24.5 percent on average between September 2014 and September 2015. 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. 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.

Readily-Convertible-to-Cash (RCC) Considerations

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 RCC. However, as midstream infrastructure improves in the medium term and commercially viable markets develop, RCC conclusions will need to be revisited.

Liquefied Natural Gas

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

Historically, the United States has imported LNG through regasification facilities located on the East and Gulf Coasts. The development of these facilities was supported by the \$12 per MMBtu natural gas prices in 2008. However, given the \$2 to \$4 prices for 2013 through 2015, along with the increased supply of shale gas, regasification facilities have begun to convert from regasification to liquefaction in anticipation of LNG export. The U.S. LNG export licensing process is administered by the DOE under the Natural Gas Act. To speed up the licensing process, the DOE has begun to prioritize projects on the basis of their merits. With low-cost players already in the market, at least some of the LNG players are considering entering into tolling arrangements to deliver LNG to international markets.

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

³ Source: <http://marketrealist.com/2015/12/us-natural-gas-inventory-rising-since-april-2015>.

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

Hedge Accounting

There has been an increasing trend among companies to use non-GAAP financial measures to discuss operating and economic performance as opposed to applying hedge accounting because of the level of investment required to implement and run a hedging program. Although non-GAAP financial measures may serve a similar purpose and enable companies to avoid applying hedge accounting, companies using these measures may be required to provide some additional disclosures to avoid misleading financial statement users.

The FASB has taken action to make hedge accounting easier for companies to apply and for users of the financial statements to understand. The Board is expected issue an updated ED on hedge accounting in the first half of 2016. The new standard is expected to reduce the complexity and administrative burden of applying hedge accounting.

In its deliberations on hedge accounting, the FASB has tentatively decided to eliminate the concept of splitting the changes in fair value of the hedging derivative between effective and ineffective portions. For cash flow hedges, the entire change in fair value of the hedging instrument would be recorded in other comprehensive income (OCI) until the period in which the hedged item affects earnings. For fair value hedges, the proposed standard continues to require that the entire change in fair value of the hedge instrument be recorded in the same line item on the income statement as the change in value of the hedged item. The entire change in the fair value of the hedging instrument would be recorded in the same line item as the hedged item either upon reclassification of the accumulated OCI or immediately for fair value hedges. In addition, quantitative assessments of hedge effectiveness would only be required at the inception of a hedge unless facts and circumstances change and an updated effectiveness assessment is warranted. For nonfinancial items, the FASB has tentatively agreed that an entity may designate a contractually specified component that is linked to a contractually stated rate or index as the hedged item. For additional details of the hedge accounting model, see [Section 5](#).

Regulation G — Disclosures about Non-GAAP Financial Measures

Entities that do not use hedge accounting but use non-GAAP measures to explain performance will be subject to Regulation G. Under Regulation G, public companies that issue financial information (e.g., earnings releases, MD&A) presented on a non-GAAP basis must reconcile the disclosed non-GAAP financial measure to the most directly comparable GAAP financial measure. P&U companies typically use non-GAAP financial measures to assess operational performance (e.g., commodity margin, adjusted EBITDA excluding the mark-to-market impact of economic hedging activities, or inventory value adjusted for the price of physical forward contracts hedging the inventory). P&U companies should ensure that any reconciliation between the GAAP and non-GAAP measure is accompanied by explanations that describe how the adjustment is calculated and how the supplementary non-GAAP measure helps stakeholders assess the company's operations.

Bundled Contracts

Contract Assessment Considerations

Although electricity procurement is typically the primary purpose of a power purchase, renewable energy contracts often include renewable energy credits (RECs) along with the energy output. These types of contracts are often referred to as bundled contracts. In accounting for such contracts, a selling entity should consider the guidance in the FASB's and IASB's new revenue standard, which was issued by the FASB as ASU 2014-09 (codified in ASC 606) and by the IASB as IFRS 15. For further details about the new standard, see [Section 5](#).

Specifically, P&U entities should carefully evaluate their contracts with customers for multiple products and services and assess whether (1) products or services separated in accordance with the guidance in other Codification topics should be accounted for under ASU 2014-09 or (2) an entity should apply ASU 2014-09's guidance on distinct performance obligations when separating multiple products and services in contracts with customers. While the new guidance is not expected to significantly change current practice for rate-regulated operations, P&U entities will need to consider the new standard and potentially revisit their accounting for bundled arrangements.

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

- *Lease accounting* — As noted in ASC 840-10-15-3, the objective of this portion of the contract assessment is to identify whether an arrangement “contains a lease.” Accordingly, a contract could contain lease and nonlease elements. ASC 840-10-15-18 notes that the nonlease elements “shall be accounted for in accordance with other applicable generally accepted accounting principles (GAAP).” If a REC is **not** considered a unit of output and the contract is considered a lease, the contract includes nonlease elements that must be separately assessed. Whether a REC is a unit of output continues to be a company policy that must be elected and applied consistently. See [Lease Accounting](#) above for additional information.
- *Derivative accounting* — To the extent that an element in a bundled arrangement is considered a nonlease element, entities would need to assess it to determine whether it meets the derivative requirements. Because ASC 815-15 does not specify how to identify a host for executory contracts with multiple elements, two views on identifying the host contract in a bundled arrangement have developed in the P&U industry:
 - *Predominant characteristics* — In this view, the host is defined as the portion of the contract that embodies the most significant economics under the transaction on the basis of the relative value contribution of the various contract elements. For bundled electricity contracts, electricity is often (but not always) the element with the most significant value and thus is defined as the host; therefore, the entire contract (including any potential nonderivative elements) would be deemed a derivative contract and fair value would be assessed for the entire contract. While we believe that this approach is used by some in practice, we also think that it increases accounting risk and that reporting entities should consult with their auditors about whether this approach continues to be acceptable.
 - *Nonderivative host* — In this view, the host is defined as the portion of the contract that does not meet the derivative criteria. For example, the host contract in a bundled contract containing both electricity and RECs would be the REC element (as long as the REC element does not qualify as a derivative), and an entity would assess whether the electricity forward needs to be bifurcated. If the electricity portion of the contract must be bifurcated, reporting entities are permitted to elect the NPNS scope exception for embedded derivatives under ASC 815-15-55-21 (as long as the appropriate criteria are met). It would be rare for an entity to recognize an inception gain or loss as a result of bifurcating an embedded derivative.

ISO/RTO Considerations

In 2013, the 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 the delivery point of the forward contract differs from the location of the purchaser's customers. In 2015, the FASB issued ASU 2015-13, which clarified the Board's view that the use of locational margin pricing 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 purchase or normal sales. For further details, refer to [Section 5](#).

Gross/Net Income Statement Presentation

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

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

Volumetric Data

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



Section 5
Accounting Standards
Codification Update

Reporting of Discontinued Operations

Background

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

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

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

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

Thinking It Through

Before the new guidance, sales of property (e.g., a power plant) often qualified for treatment as a discontinued operation because the property qualified as a component of an entity. Under the new guidance, regardless of whether a P&U entity disposes of a reportable segment, an operating segment, a subsidiary, or another component, the disposal’s importance to the entity and financial statement users is critical to whether the disposal represents a strategic shift. Given the ASU’s lack of clarity on this topic, a P&U entity will need to use judgment in determining whether a strategic shift has occurred.

Scope

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

Presentation and Disclosure

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

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

Thinking It Through

In certain situations, discontinued business units/strategies may be completely rolled off from financial data during the current period. However, in preparing their disclosures, P&U entities should be careful to include such zero balances in disclosure sections for which comparative prior periods must be presented because of the existence of balances (e.g., disclosures about derivative gross volume under ASC 815).

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

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

Effective Date and Transition

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

Going Concern

Background

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

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

Time Horizon

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

Disclosures

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

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

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

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
<ul style="list-style-type: none"> • Principal conditions or events. • Management’s evaluation. • Management’s plans. 	<ul style="list-style-type: none"> • 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.

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

Consolidation

Background

In February 2015, the FASB issued [ASU 2015-02](#), which amends the consolidation requirements in ASC 810. The issuance of the ASU concluded the FASB’s ongoing project to eliminate the deferral of ASU 2009-17 (formerly Statement 167) for certain entities. While the Board’s focus for the project was largely on the investment management industry, the amendments in the ASU could also affect a P&U entity’s consolidation conclusions. Specifically, P&U entities should consider whether the ASU’s provisions regarding (1) when limited partnerships and similar entities should be consolidated, and (2) variable interests held by the reporting entity’s related parties or de facto agents affect its consolidation conclusions. These provisions may have an impact on certain investment structures entered into by P&U entities, including nuclear decommissioning trusts.

For a comprehensive review of ASU 2015-02, see Section E.5 of Appendix E in Deloitte’s *Consolidation — A Roadmap to Identifying a Controlling Financial Interest*.

Determining Whether a Limited Partnership (or Similar Entity) Is a VIE

The ASU amends the definition of a VIE for limited partnerships and similar entities. Under the ASU, a limited partnership is considered a VIE regardless of whether it has sufficient equity or meets the other requirements to qualify as a voting interest entity **unless** a single LP or a simple majority of all partners (including interests held by the GP and its related parties) has substantive kick-out rights (including liquidation rights) or the LPs have participating rights. As a result of the amendments to the definition of a VIE for limited partnerships and similar entities, partnerships historically not considered VIEs will need to be evaluated under the new VIE consolidation model. Conversely, partnership arrangements that include simple-majority kick-out or participating rights (rather than single-partner rights) may no longer be VIEs.

Thinking It Through

P&U entities often enter into limited partnerships (1) when required to contribute to nuclear decommissioning trusts and (2) as a mechanism to finance new capital projects (e.g., transmission and distribution projects, or alternative energy projects such as the construction of wind or solar facilities). Although the consolidation conclusion may not change, a P&U entity will need to evaluate all of its limited partnership interests under the new guidance described above. In addition, even if a P&U entity determines that it does not need to consolidate a VIE, it would have to provide the existing extensive disclosures for any VIEs in which it holds a variable interest.

Determining Whether an Entity Other Than a Limited Partnership (or Similar Entity) Is a VIE

The ASU clarifies how a reporting entity should evaluate the condition in ASC 810-10-15-14(b)(1) (whether the equity holders (as a group) have power) for entities other than limited partnerships. Specifically, the ASU clarifies that in situations in which the equity holders have delegated the decision-making responsibility, and the decision maker's fee arrangement is a variable interest under ASC 810-10-55-37, the evaluation of this criterion should focus on whether the equity holders have power over the legal entity's most significant activities through their equity interests. In making this assessment, the reporting entity should consider whether the equity holders have the right to replace the decision maker. This is a significant change from the previous guidance, under which kick-out rights were only considered if they were held by a single party.

Determining Who Should Consolidate

In a manner consistent with the current guidance, a reporting entity would be considered the primary beneficiary of a VIE under the ASU (and would therefore be required to consolidate the VIE) when it has met the power and economics conditions. This would apply to all entities that are VIEs, including limited partnerships and similar entities that are VIEs.

Under the ASU, the evaluation of who controls a limited partnership that is **not** considered a VIE focuses on the kick-out or liquidation rights held by the "unrelated" LPs. That is, the analysis would concentrate on whether any of the LPs have the substantive ability to unilaterally dissolve the limited partnership or otherwise remove the GP without cause and, if so, should consolidate the partnership.

Effects of Related Parties

The ASU significantly amends how variable interests held by a reporting entity's related parties or de facto agents affect its consolidation conclusion. Among other items, the need to perform the related-party tiebreaker test (as well as mandatory consolidation by one of the related parties) will be less frequent under the ASU than under current U.S. GAAP. If power is not considered shared among the related parties, the related-party tiebreaker test would be performed only by parties in the decision maker's related-party group that are under common control and that together possess the characteristics of a controlling financial interest. In this situation, the purpose of the test would be to determine whether the decision maker or a related party under common control of the decision maker is required to consolidate the VIE.

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

Effective Date and Transition

For public business entities (PBEs), the ASU's guidance is effective for annual periods, and interim periods within those annual periods, beginning after December 15, 2015. For entities other than PBEs, the ASU's guidance is effective for annual periods beginning after December 15, 2016, and interim periods beginning after December 15, 2017. The ASU would allow early adoption for all entities but would require entities to apply the guidance as of the beginning of the annual period

containing the adoption date. Modified retrospective application (including a practicability exception) would be required, with an option for full retrospective application.

Thinking It Through

When reviewing the new consolidation guidance, P&U entities should carefully consider the extent to which they may need to revise processes and new controls to apply the new ASU, particularly those processes and controls related to an entity's obtaining the information necessary to meet the VIE disclosure requirements. In addition, P&U entities should consider the effect of the new guidance when entering into new transactions.

Pushdown Accounting (ASU 2014-17 and ASU 2015-08)

Background

In November 2014, the FASB issued [ASU 2014-17](#), which gives an acquired entity the option of applying pushdown accounting in its stand-alone financial statements upon a change-in-control event. Before ASU 2014-17, there was limited guidance in U.S. GAAP on determining whether an acquired entity can establish a new accounting and reporting basis in its stand-alone financial statements (commonly referred to as "pushdown" accounting). ASC 805-50-S99-1 through S99-41 contain pushdown accounting requirements for SEC registrants. Under this guidance, pushdown accounting is (1) prohibited when 80 percent or less of an entity's ownership is acquired, (2) permitted when between 80 percent and 95 percent is acquired, and (3) required when 95 percent or more is acquired.

Key Provisions of ASU 2014-17

An acquired entity that elects pushdown accounting would apply the measurement principles in ASC 805 to push down the measurement basis of its acquirer to its stand-alone financial statements. In addition, the acquired entity would be required to provide disclosures that enable "users of financial statements to evaluate the effect of pushdown accounting."¹

ASU 2014-17 also concluded that when applying pushdown accounting, an acquired entity would be:

- Prohibited from recognizing acquisition-related debt incurred by the acquirer unless the acquired entity is required to do so in accordance with applicable U.S. GAAP (e.g., because the acquired entity is legally obligated).
- Required to recognize the acquirer's goodwill.
- Prohibited from recognizing bargain purchase gains that resulted from the change-in-control transaction or event; instead, the acquiree would recognize such gains as an adjustment to equity (i.e., APIC).

The ASU also gives a subsidiary of an acquired entity the option of applying pushdown accounting to its stand-alone financial statements, even if the acquired entity (i.e., the direct subsidiary of the acquirer) elected not to apply pushdown accounting.

The ASU does not apply to common-control transfers; the guidance on accounting for transactions by entities under common control is included in ASC 805-50. A company that receives the net assets or equity interests in a common-control transfer should record those net assets or equity interests at the transferor's carrying amounts. However, if pushdown accounting was not applied by the transferor, the financial statements of the receiving entity would reflect the transferred net assets at the historical cost of the parent of the entities under common control, which would result in the parent's basis being pushed down to the receiving entity.

¹ Entities would achieve that disclosure objective by providing the relevant disclosures required by ASC 805.

Conforming SEC and FASB Guidance

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

In May 2015, the FASB issued [ASU 2015-08](#), which removes references to the SEC's SAB Topic 5.J on pushdown accounting from ASC 805-50. The SEC's SAB 115 had superseded the guidance in SAB Topic 5.J in connection with the FASB's November 2014 release of ASU 2014-17. The amendments in ASU 2015-08 therefore conform the FASB's guidance on pushdown accounting with the SEC's.

Effective Date

The guidance in ASU 2014-17 became effective on November 14, 2014. As of the effective date, an acquired entity would be permitted to elect to apply pushdown accounting arising as a result of change-in-control events occurring before the standard's effective date as long as (1) the change-in-control event is the most recent change-in-control event for the acquired entity and (2) the election is preferable. Entities would not be permitted to unwind a previous application of pushdown accounting (i.e., an acquired entity can change its election for the most recent change-in-control transaction or event from not applying pushdown accounting to applying pushdown accounting, if preferable, but not vice versa).

For more information about ASU 2014-17, see Deloitte's September 2014 *EITF Snapshot*.

Application of NPNS Scope Exception to Certain Electricity Contracts Within Nodal Energy Markets (ASU 2015-13)

Background

Derivatives are measured at fair value, with changes in fair value recorded in net income. ASC 815 contains certain scope exceptions for contracts that otherwise meet the definition of a derivative, including the normal purchases and normal sales (NPNS) scope exception.²

The term "nodal energy markets" refers to an interconnected wholesale energy transmission grid administered by regional independent system operators (ISOs). The ISOs operate various "nodes" within the grid where electricity is delivered and withdrawn on the basis of market rates.³ The price differential between nodes (delivery point and withdrawal point) represents locational marginal pricing (LMP) charges. As electricity is delivered into the nodal market, the ISOs take "flash title" of the electricity and charge their counterparties the LMP charge on the basis of the market price at that node.

² For a transaction to qualify for the NPNS exception, (1) the terms of the contract must be consistent with the terms of a normal purchase or normal sale, (2) the price must be clearly and closely related to the underlying asset, and (3) physical settlement must be probable at inception and throughout the contract.

³ Market rates are based on the economic effects of physical supply, demand, and the availability of transmission capacity (e.g., congestion).

The following example illustrates this scenario:

Example

A utility company enters into a forward purchase contract with a power-generating company for delivery of 10,000 MWh daily over a five-year period. The power-generating company delivers the daily electricity to the utility company at Location Y. The utility company needs the electricity at Location Z so that it can deliver electricity to its customers.

Each day, the utility company sells electricity to the ISO, who takes flash title, at Location Y for \$45 per MWh.

Simultaneously, the utility company purchases electricity from the ISO at Location Z for \$46 per MWh so that it can deliver the electricity to its consumers, incurring an LMP charge of \$1 per MWh.

An issue was raised with the EITF about whether the forward purchase from the power-generating company is net settled when the utility sells daily to the ISO at Location Y, in which case the forward purchase contract would fail to qualify for the NPNS scope exception because this exception requires that physical settlement be probable. Many felt that the transaction described above does not constitute net settlement because it is accompanied by a simultaneous purchase at the customer load zone (Location Z) and the daily sale and purchase with the ISO is the manner in which physical power is transmitted in a nodal market.

Summary

The EITF's decisions with respect to the issue were ratified at its June 18, 2015, meeting. As a result, the FASB issued [ASU 2015-13](#) in August 2015. The ASU reflects the EITF's consensus, stating that a forward purchase or sale of electricity in which electricity must be physically delivered through a nodal energy market operated by an ISO and in which an entity incurs transmission costs on the basis of LMP charges would meet the physical-delivery requirement under the NPNS scope exception. The EITF's consensus is supported by its observations that the substance of such a transaction is that the entity physically delivers electricity to its customers. The ASU clarifies that transactions in which electricity is transmitted through an ISO from one jurisdiction to another, and in which LMP charges are incurred, are within its scope and would therefore qualify for the NPNS scope exception.

Effective Date and Transition

For all entities, the final consensus is effective upon issuance. Entities must adopt the guidance prospectively for any qualifying new or existing contract. If the NPNS exception is elected for an existing derivative, an entity will no longer mark the derivative to market and its carrying value will be its fair value at the time of designation. The carrying value would be subsequently amortized to income over the remaining contract term.

Thinking It Through

The consensus giving rise to ASU 2015-13 was a very positive answer for the P&U industry and reflected a substance-based approach to standard setting. Although ASU 2015-13 is expected to have a pervasive impact given the number of P&U entities that operate in nodal energy markets, we do not expect disruption in terms of legacy accounting. If a company was applying NPNS to these types of arrangements in the past, the ASU effectively validates the historical accounting. On the other hand, an entity that felt that NPNS was prohibited in the past does not have a historical accounting issue since NPNS is elective. Further, since NPNS elections can be made post-inception, those companies can designate existing contracts now if they wish.

It is important to note that the guidance in the ASU is explicitly limited to electricity transactions in nodal markets as described therein and should not be analogized to other commodity types or transportation/transmission arrangements (e.g., gas transportation, barrel-backs).

Financial Instruments — Recognition and Measurement

Background

On January 5, 2016, the FASB issued [ASU 2016-01](#), which amends the Board's guidance on the recognition and measurement of financial instruments. During deliberations of the FASB's February 2013 [proposed ASU](#) (which outlined a new model that was largely converged with the IASB's for the classification and measurement of financial instruments), the Board had decided to abandon the converged approach and retain much of the existing requirements in U.S. GAAP. However, the amendments in the final ASU contain significant changes related to:

- Accounting for equity investments (apart from those that are accounted for under the equity method or those that are consolidated).
- Impairment of equity investments measured in accordance with a practicability exception.
- 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.
- Disclosure requirements for financial assets and financial liabilities.

For PBEs, the new standard will be effective for fiscal years beginning after December 15, 2017, including interim periods therein. For all other entities, it will be effective for fiscal years beginning after December 15, 2018, and interim periods for the following year. Early adoption of certain of the standard's provisions is permitted for all entities for financial statements that have not yet been issued, provided that the provisions are adopted as of the beginning of the fiscal year of adoption. Non-PBEs would be permitted to adopt the standard in accordance with the effective date for PBEs.

For more information about the final ASU and its potential impact, refer to Deloitte's January 12, 2016, [Heads Up](#).

Classification and Measurement of Equity Investments

The amendments in ASU 2016-01 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 permits 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 exception is not available to reporting entities that are investment companies or broker-dealers in securities.

Impairment Assessment of Equity Investments

The amendments eliminate the requirement for an entity that has elected the practicability exception to assess whether the equity investment is other-than-temporarily impaired. Instead, as of each reporting period, the entity would qualitatively consider the following indicators (from ASC 321-10-35-3, as added by the ASU) to determine whether the investment is impaired:

- a. A significant deterioration in the earnings performance, credit rating, asset quality, or business prospects of the investee
- b. A significant adverse change in the regulatory, economic, or technological environment of the investee
- c. A significant adverse change in the general market condition of either the geographical area or the industry in which the investee operates
- d. A bona fide offer to purchase, an offer by the investee to sell, or a completed auction process for the same or similar investment for an amount less than the carrying amount of that investment



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

If, on the basis of the qualitative assessment, the equity investment is impaired, the investee would be required to record an impairment equal to the amount by which the carrying value exceeds fair value. The investee would no longer be required to evaluate whether such impairment was other than temporary.

Thinking It Through

Under current U.S. GAAP, marketable equity securities that are not accounted for as equity-method investments are classified as either held for trading (with changes in fair value recognized in earnings) or available for sale (AFS) (with changes in fair value recognized in other comprehensive income (OCI)). Investments in nonmarketable equity securities that are not accounted for as equity-method investments are measured at cost (less other-than-temporary impairment). The amendments eliminate the AFS classification category for marketable equity securities as well as the cost method of accounting for qualifying nonmarketable equity securities. As a result of these changes, entities with large portfolios of cost-method investments or equity investments classified as AFS could experience volatility in earnings.

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 require an entity to separately recognize in OCI any changes in fair value associated with instrument-specific credit risk. This requirement is one of the provisions noted above that may be early adopted. 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; however, the guidance also acknowledges that there may be other methods an entity can use to determine instrument-specific credit risk.

Changes to Disclosure Requirements

For non-PBEs, the amendments eliminate the requirement to disclose the fair value of financial instruments measured at amortized cost. The removal of this requirement is one of the provisions noted above that may be early adopted. In addition, for such financial instruments, PBEs will 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 PBE 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 statements 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).

Financial Instruments — Impairment

Background

The FASB spent much of 2015 drafting its final guidance on impairment. It also formed a TRG on impairment, comprising financial statement preparers, auditors, and regulators. FASB board members attend the TRG’s meetings, and representatives from the SEC and PCAOB are also invited to observe.

The objective of the impairment TRG is to help the FASB resolve issues related to implementation of the standard both before and after the new guidance is issued. At a private session with the TRG, the FASB recently sought feedback on a staff draft of the final guidance. It is unclear whether the FASB will seek additional feedback from the TRG at other such sessions before the standard is issued.

Project Overview

The amendments will introduce the current expected credit loss (CECL) model, which is a new impairment model⁴ based on expected losses rather than incurred losses. Under the CECL model, an entity would recognize as an allowance its estimate of the contractual cash flows not *expected* to be collected. The FASB believes that the CECL model will result in more timely recognition of credit losses and will reduce the complexity of U.S. GAAP by decreasing the number of credit impairment models used to account for debt instruments.⁵

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

The CECL Model

Scope

The CECL model will apply to most⁶ debt instruments (other than those measured at fair value through net income (FVTNI)), trade receivables, lease receivables, reinsurance receivables that result from insurance transactions, financial guarantee contracts,⁷ and loan commitments. However, AFS debt securities will be excluded from the model's scope and will continue to be assessed for impairment under ASC 320 (the FASB has proposed limited changes 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 an impairment allowance equal to the current estimate of expected credit losses (i.e., all contractual cash flows that the entity does not expect to collect) for financial assets as of the end of the reporting period. Credit impairment will be recognized as an allowance — or contra-asset — rather than as a direct write-down of the amortized cost basis of a financial asset.

⁴ Although impairment began as a joint FASB and IASB project, constituent feedback on the boards' "dual-measurement" approach led the FASB to develop its own impairment model. The IASB, however, continued to develop the dual-measurement approach and issued final impairment guidance based on it as part of the July 2014 amendments to IFRS 9. For more information about the IASB's impairment model, see Deloitte's August 8, 2014, [Heads Up](#).

⁵ Note that the proposed CECL model would replace or amend several existing U.S. GAAP impairment models. See Appendix B of Deloitte's March 13, 2015, [Heads Up](#) for a tabular summary of those models.

⁶ The CECL model would not apply to the following debt instruments:

- Loans made to participants by defined contribution employee benefit plans.
- Policy loan receivables of an insurance entity.
- Pledge receivables (promises to give) of a not-for-profit entity.
- Loans and receivables between entities under common control.

⁷ The CECL model would not apply to financial guarantee contracts that are accounted for as insurance or measured at FVTNI.

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, an “entity would not be required to recognize a loss on a financial asset in which the risk of nonpayment is greater than zero [but] the amount of loss would be zero.”⁸ U.S. Treasury securities and certain highly rated debt securities may be assets the FASB contemplated when it allowed an entity to recognize zero credit losses on an asset, but the Board decided not to specify the exact types of assets. Nevertheless, the requirement to measure expected credit losses on financial assets whose risk of loss is low is likely to result in additional costs and complexity.

Measurement of Expected Credit Losses

Under the amendments, an entity’s estimate of expected credit losses represents all contractual cash flows that the entity does not expect to collect over the contractual life of the financial asset. When determining the contractual life of a financial asset, the entity would consider expected prepayments but would not be allowed to consider expected extensions unless it “reasonably expects that it will execute a troubled debt restructuring with the borrower.”⁹

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

Thinking It Through

Measuring expected credit losses will most likely be a significant challenge for all entities. Entities may also incur one-time or recurring costs associated with implementing the CECL model, such as those related to system changes, data collection, and 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 would be required to evaluate financial assets within the scope of the model on a collective (i.e., pool) basis when similar risk characteristics are shared. If a financial asset does not share similar risk characteristics with the entity’s other financial assets, the entity would evaluate the financial asset individually. If the financial asset is individually evaluated for expected credit losses, the entity would not be allowed to ignore available external information such as credit ratings and other credit loss statistics.

⁸ Quoted text is from the FASB’s [summary](#) of tentative Board decisions reached at the joint meeting of the FASB and IASB on September 17, 2013.

⁹ Quoted text is from the FASB’s [summary](#) of tentative Board decisions reached at its September 3, 2014, meeting.

Thinking It Through

Under the new guidance, an entity will be required to collectively measure expected credit losses on financial assets that share similar risk characteristics (including HTM securities). While the concept of pooling and collective evaluation currently exists in U.S. GAAP for certain loans, the FASB has not specifically defined “similar risk characteristics.” As a result, it remains to be seen whether the FASB expects an aggregation based on “similar risk characteristics” to be consistent with the existing practice of pooling purchased credit-impaired (PCI) assets on the basis of “common risk characteristics.” Entities may need to make changes to systems and processes to capture loss data at more granular levels depending on the expectations of market participants such as standard setters, regulators, and auditors.

AFS Debt Securities

The impairment of AFS debt securities will continue to be accounted for under ASC 320. However, the amendments revise that guidance by:

- Limiting the credit losses recognized to the difference between the security’s amortized cost and its fair value.
- Requiring an entity to use an allowance approach (vs. permanently writing down the security’s cost basis).
- Removing the requirement that an entity must consider the length of time fair value has been less than amortized cost when assessing whether a security is other-than-temporarily impaired.
- Removing the requirement that an entity must 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 that entities recognize the impairment amount only related to credit in net income and the noncredit impairment amount in OCI. However, entities would use an allowance approach when recognizing credit losses (as opposed to a permanent write-down of the AFS security’s cost basis). As a result, in both of the following instances, an entity would reverse credit losses through current-period earnings on an AFS debt security:

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

These revisions to the impairment model in ASC 320 could result in earlier recognition of impairment.

PCI Assets

PCI assets are acquired financial assets for which there has been a “more than insignificant” deterioration in credit quality since origination. An entity will measure expected credit losses for these assets the same way it measures expected credit losses for originated and purchased non-credit-impaired assets.

Upon acquiring a PCI asset, the entity would recognize as its allowance for expected credit losses the amount of contractual cash flows not expected to be collected as an adjustment that increases the cost basis of the asset (the “gross-up” approach). After initial recognition of the PCI 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. Consequently, any subsequent changes to the entity’s estimate of expected credit losses — whether unfavorable or favorable — would be recorded as impairment expense (or reduction of expense) during the period of change. Interest income recognition would be based on the purchase price plus the initial allowance accreting to the contractual cash flows.

Thinking It Through

Under the current accounting for PCI assets, an entity recognizes unfavorable changes in cash flows as an immediate credit impairment but treats favorable changes in cash flows that are in excess of the allowance as prospective yield adjustments. The CECL model’s approach to PCI 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.

An acquired asset is currently 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. However, as noted above, under the FASB’s tentative approach, a PCI asset is an acquired asset for which there has been a “more than insignificant” deterioration in credit quality since origination. The FASB revised the definition of a PCI asset partially in response to stakeholder feedback suggesting that if an entity were to recognize expected credit losses in its income statement upon purchase of any asset, regardless of the level of credit deterioration in the asset’s credit quality since origination, the entity would be “double-counting” expected credit losses on that asset because those losses were already contemplated in the purchase price. Although the FASB decided not to require an entity to apply the gross-up approach to all acquired assets, stakeholders are likely to support the change to the definition of a PCI asset because an entity is likely to apply the gross-up approach to more assets than it would have under the requirements in the proposed amendments. The FASB has also indicated that the final standard will include implementation guidance to help entities assess whether there has been a “more than insignificant” deterioration in a purchased asset’s credit quality since origination.

Disclosures

Many of the disclosures required under the amendments are similar to those already required under U.S. GAAP as a result of [ASU 2010-20](#). Accordingly, entities will need to disclose information related to:

- Credit quality.¹⁰
- Allowance for expected credit losses.
- Policy for determining write-offs.
- Past-due status.
- PCI assets.
- Collateralized financial assets.

In addition, an entity will need to disclose credit-quality indicators for each asset class, disaggregated by vintage, for a period not to exceed five years (although upon transition, the entity will be required to provide this disclosure only for the current and prior-year amortized cost balances). The disclosure will be required for annual and interim periods and would not be required for an entity’s revolving lines of credit.

¹⁰ Short-term trade receivables resulting from revenue transactions within the scope of ASC 605 are excluded from these disclosure requirements.

Transition

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

Other Significant Decisions

The new guidance will also reflect the FASB's tentative decisions related to the following:

- Practical expedients when measuring expected credit losses.
- Write-offs.
- Modifications.
- Certain beneficial interests within the scope of ASC 325-40.
- Loan commitments.
- Transition disclosures.

Effective Date and Early Adoption

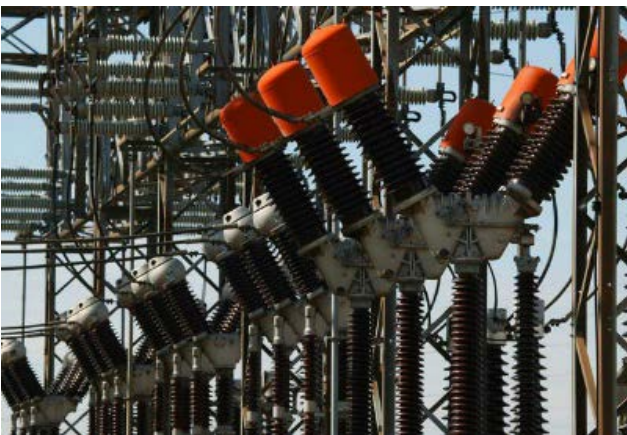
The Board tentatively decided the following:

- For PBEs that meet the definition under U.S. GAAP of an SEC filer, the final standard will be effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years.
- For PBEs that do not meet the definition of an SEC filer, the final standard will be effective for fiscal years beginning after December 15, 2019, including interim periods within those fiscal years.
- For all other entities, the final standard will be effective for fiscal years beginning after December 15, 2019, and interim periods within those fiscal years beginning after December 15, 2020.

The Board also tentatively decided that PBEs that meet the definition under U.S. GAAP of an SEC filer will not be permitted to early adopt the final standard. All other entities will be permitted to early adopt the final standard, but not before an SEC filer would adopt the standard.

Next Steps

The FASB expects to issue a final standard in the first quarter of 2016. For a comprehensive summary of the impairment project to date, see the [project update page](#) on the FASB's Web site.



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 the CECL model, for any approach that is based solely on historical loss experience, an entity would need to consider the effect of forward-looking information over the remaining contractual life of a financial asset. In addition, when an entity is “developing its estimate of expected credit losses . . . for periods beyond which the entity is able to make or obtain reasonable and supportable forecasts, [the] entity is allowed to revert to its [unadjusted] historical credit loss experience.”¹¹

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 would need 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).

Financial Instruments — Hedging

Background

As part of its project on targeted improvements to hedge accounting, the FASB held several educational sessions during 2015. Those sessions have thus far culminated in two decision-making meetings at which the FASB made a number of tentative decisions that, if ultimately adopted, would significantly modify certain aspects of the existing hedge accounting model. The Board hopes to issue a proposed ASU reflecting these tentative conclusions in the second quarter of 2016.

Overall Hedging Model

The FASB tentatively decided to retain, for both fair value and cash flow hedges, (1) the highly effective threshold used to qualify for hedge accounting under current U.S. GAAP and (2) the current guidance allowing an entity to voluntarily dedesignate a hedging relationship. Further, under the proposal, an entity would still need specified documentation in place at hedge inception, including a description of its method for quantitatively assessing hedge effectiveness (unless the criteria for using the shortcut or critical-terms-match methods are met, obviating the need for quantitative assessments). However, an entity would not have to actually complete that initial quantitative assessment of hedge effectiveness until the end of the reporting period in which it designated the hedge (i.e., an entity could have up to three months to complete the initial quantitative assessment of effectiveness). Also under the proposal, after hedge inception, an entity would need to perform quantitative assessments of hedge effectiveness only when facts and circumstances change.

The Board also tentatively decided to eliminate the traditional concept of hedge ineffectiveness:

- For highly effective cash flow hedging relationships, the entire change in the fair value of the hedging instrument included in an entity’s hedge effectiveness assessment would initially be recorded in OCI. When the hedged item affects earnings, the amount in accumulated OCI would be reclassified to the same income statement line as the earnings effect of the hedged item. Any portion of the change in the fair value of the hedging instrument that

¹¹ Quoted text is from the FASB’s [summary](#) of tentative Board decisions reached at its August 13, 2014, meeting.

is excluded from an entity's hedge effectiveness assessment would be recognized immediately in earnings (but presented on the same income statement line as the earnings effect of the hedged item).

- For highly effective fair value hedging relationships, the entire change in the fair value of the hedging instrument would be recorded in earnings immediately in the same income statement line as the hedged item.
- For highly effective net investment hedging relationships, the entire change in the fair value of the hedging instrument included in an entity's hedge effectiveness assessment would initially be recorded as part of the cumulative-translation adjustment in OCI. When the hedged item affects earnings, the amount in accumulated OCI would be reclassified to the same income statement line as the earnings effect of the hedged item. Any portion of the change in the fair value of the hedging instrument that is excluded from an entity's hedge effectiveness assessment would be recognized immediately in earnings.

In addition, the FASB tentatively decided to require additional disclosure about (1) cumulative-basis adjustments for fair value hedges and (2) the effect of hedging on individual income statement line items. It also tentatively decided to require expanded qualitative disclosures about the quantitative goals, if any, that an entity set to achieve its hedging objectives.

Nonfinancial Hedging Relationships

For hedges of nonfinancial items, the Board tentatively decided to change existing GAAP to permit an entity to designate as a hedged item a contractually specified component or ingredient that is linked to a contractually stated rate or index. Any cap, floor, or negative basis that is related to the pricing of a contractually specified component of a nonfinancial item would not preclude designation of that component as a hedged item — an entity would just need to consider such pricing features in its assessment of hedge effectiveness.

Thinking It Through

The FASB's tentative 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.

Financial Hedging Relationships

For hedges of financial items, the FASB tentatively decided to (1) allow the contractually specified index rate in a variable-rate hedged item to be the designated interest rate risk (thereby relieving entities of the need to designate a benchmark interest rate for cash flow hedges of variable-rate instruments); (2) retain the existing benchmark interest rate definition for hedges of fixed-rate instruments, with minor modifications to eliminate inconsistencies; and (3) designate the Securities Industry and Financial Markets Association (SIFMA) Municipal Swap index as a permitted benchmark interest rate.

In addition, the tentative decisions would allow an entity, for fair value hedges of interest rate risk, to:

- Consider only the effects of the designated hedged risk (e.g., interest rate risk) on a prepayment option when determining the change in the value of the debt for hedges of callable debt.
- Designate as the hedged risk only a portion of the hedged item's term (i.e., compute the change in the hedged item's fair value by using the same term as that of the hedging instrument).
- Calculate the change in the fair value of the hedged item attributable to changes in the benchmark interest rate by using either (1) total coupon cash flows or (2) only those cash flows related to the benchmark interest rate. However, an entity would be required to use total coupon cash flows when the effective interest rate of the hedged item is less than the benchmark interest rate on the date of hedge designation.

Shortcut Method

The FASB tentatively decided to retain the shortcut method in current U.S. GAAP. However, the Board also tentatively decided to allow an entity to document at hedge inception the long-haul method it would use to measure hedge ineffectiveness if the shortcut method could not be applied. That is, if the entity later determines that continued use of the shortcut method is inappropriate, it can continue the hedging relationship by using the long-haul method designated at inception as long as the hedging relationship has been highly effective since inception.

Next Steps

The FASB staff will (1) continue deliberations, including consideration of whether alternative hedge documentation requirements for private companies are warranted; (2) develop a staff draft reflecting the Board's decisions; (3) analyze the costs, benefits, and potential complexity of the tentative decisions; and (4) identify any issues that need to be brought back to the Board for a vote. In addition, the FASB will need to address transition and the comment period of the proposed ASU.

Thinking It Through

When the proposal is issued, P&U entities should carefully analyze it to assess its possible ramifications on their hedging strategies, systems, and internal controls, and they are encouraged to provide feedback on the proposed amendments to the FASB. Multinational companies should note that the FASB's proposed hedging model is likely to differ significantly from the IASB's IFRS 9 hedging model.

To follow the status of the FASB's hedging project, see the [project page](#) on Deloitte's US GAAP Plus Web site.

Liabilities and Equity — Targeted Improvements

Background

In November 2014, the FASB added to its agenda a project to "simplify the accounting guidance related to financial instruments with characteristics of liabilities and equity."¹² The project focuses on the following:

1. Application of the indexation guidance in ASC 815-40 to "equity-linked financial instruments containing 'down round' features."
2. The indefinite deferral of the liability classification guidance in ASC 480-10 on certain "mandatorily redeemable financial instruments for certain nonpublic entities and certain mandatorily redeemable noncontrolling interests."
3. Potential improvements to the accounting guidance in ASC 815-40 on "[f]reestanding contracts indexed to, and potentially settled in, an entity's own stock."
4. "Improving the navigation within the Codification."

Deliberations on the first phase of this project began at the FASB's September 6, 2015, meeting, during which the Board discussed items (1) and (2) above.

Down-Round Features

At its September 2015 meeting, the Board tentatively decided to create a new accounting model that would replace the existing guidance on such features in ASC 815-40.

¹² Quoted text is from the [project update page](#) on the FASB's Web site.

Thinking It Through

A down-round feature is a provision 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 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. For example, a warrant may specify that the strike price is the lower of \$5 per share or the common stock offering price in any future initial public offering of the shares. Under current U.S. GAAP, a contract that contains a down-round feature does not qualify as equity because it 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).

Unlike current U.S. GAAP, the Board's tentative approach related to down-round features would not preclude an entity from concluding that an instrument is indexed to the entity's own stock. For example, when an entity evaluates whether it is required to classify a freestanding warrant to acquire the entity's common stock as a liability under ASC 815-40, the existence of the down-round feature would not affect the analysis. Similarly, a down-round feature would be excluded from the analysis of whether (1) an embedded conversion feature in a debt host contract must be bifurcated as an embedded derivative under ASC 815-15 or (2) it qualifies for the derivative accounting scope exception in ASC 815-10-15-74 for contracts indexed to an entity's own stock and classified in stockholders' equity.



Under the tentative approach, if a down-round feature is triggered, the accounting for it would be aligned with the classification of the related instrument. For an equity-classified instrument, the transfer of value from the entity to the holder at the time the down-round feature is triggered would result in the recognition of a dividend to the investor. If the instrument is classified as a liability, the transfer of value resulting from the down-round feature when triggered would be recognized through a charge to earnings. If the entire instrument is classified as a liability with changes in fair value charged to earnings each reporting period, no separate adjustment would be required since the value of the down-round when triggered would inherently be captured in the periodic adjustment.

The FASB believes that existing U.S. GAAP requirements sufficiently address disclosures related to instruments with down-round features. However, the Board supported the addition of a narrow requirement for entities to disclose, in the period the down-round feature is triggered, the impact of recognizing the feature.

Thinking It Through

Under current U.S. GAAP, the existence of a down-round feature automatically precludes the instrument being evaluated (whether freestanding or embedded) from meeting the derivative accounting scope exception in ASC 815-40-15-74. As a result of the tentative approach, there would be (1) more freestanding contracts on own equity (e.g., warrants) that meet this scope exception (and thus more contracts being included within equity rather than accounted for as derivative liabilities) and (2) fewer embedded features (e.g., equity conversion features) that meet all the criteria in ASC 815-15 for bifurcation as embedded derivatives. This will reduce earnings volatility in the issuer's financial statements since derivatives liabilities — unlike equity-classified contracts — are adjusted to their fair value each reporting period.

Indefinite Deferrals Under ASC 480-10

The transition guidance in ASC 480-10 indefinitely defers the application of some of its requirements to 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 GAAP even though ASC 480-10-25 suggests that they should be classified as liabilities. The Board tentatively agreed to replace the

indefinite deferrals in ASC 480-10 with scope exceptions that have the same applicability. This is not intended to have any impact on accounting treatment but rather to improve navigation within the Codification.

Next Steps

The Board has directed its staff to proceed with drafting a proposed ASU for a vote by written ballot. The proposed ASU will have a comment period of at least 60 days.

Accounting for Goodwill for Public Business Entities and Not-for-Profit Entities

Background

In November 2013, the FASB endorsed a decision by the PCC to allow non-PBEs to amortize goodwill and perform a simplified impairment test. The Board received feedback on the PCC's decision indicating that many PBEs and not-for-profit entities had similar concerns about the cost and complexity of the annual goodwill impairment test. In response, the Board added this project to its agenda in 2014.

Current Status and Next Steps

The project is currently in the initial deliberations phase. At its meeting on October 28, 2015, the FASB tentatively decided to split the project into two phases. The first phase would focus on simplifying the goodwill impairment test. In the second phase, the Board would work with the IASB to address stakeholder concerns related to the subsequent accounting for goodwill.

At the October meeting, the Board discussed how to simplify the goodwill impairment test and tentatively decided to remove step 2, thus eliminating the requirement to complete a hypothetical purchase-price allocation. The FASB also tentatively decided not to give entities the option to perform step 2 and to instead require them to adopt the simplified impairment test prospectively. An ED related to the first phase of the project is expected to be released in the first half of 2016 with a 60-day comment period.

Clarifying the Definition of a Business

Background

In November 2015, the FASB issued a [proposed ASU](#) that would clarify the definition of a business in ASC 805 and provide a framework that an entity can use to determine whether a set of activities and assets (collectively, a "set") constitutes a business. The FASB issued the proposed ASU in response to stakeholder feedback indicating that the definition of a business in ASC 805 is too broad and that too many transactions are qualifying as business combinations even though many of these transactions may more closely resemble asset acquisitions.

Key Provisions of the Proposed ASU

The definition of a business would remain unchanged under the proposed ASU. However, the proposed ASU's Basis for Conclusions indicates that the amendments would "narrow the definition of a business and provide a framework that gives entities a basis for making reasonable judgements about whether a transaction involves an asset or a business." In addition, the proposal provides examples illustrating the application of the amendments to the determination of whether a set is a business.

Other key provisions of the proposed ASU would:

- “[P]rovide a practical way to determine when a [set] is not a business.” That is, “when substantially all of the fair value of the gross assets acquired is concentrated in a single identifiable asset or group of similar identifiable assets,” the set would not be considered a business. When this threshold is met, an entity would not need to evaluate the rest of the implementation guidance.
- Clarify that to be “a business, a transaction must include, at minimum, an input and a substantive process.”
- Provide two different sets of criteria for entities to consider in determining whether a set has a substantive process; these criteria depend on whether a set has outputs.
- Change the definition of outputs to “[t]he result of inputs and processes applied to those inputs that provide goods or services to customers, other revenues, or investment income, such as dividends or interest.”
- “[R]emove the requirement that a set is a business if market participants can replace the missing elements and continue to produce outputs.”

Convergence With IFRSs

The definition of a business in ASC 805 is currently identical to that in IFRS 3. However, the interpretation and application of the guidance in jurisdictions that apply U.S. GAAP do not appear consistent with those in jurisdictions that apply IFRSs (i.e., the definition of a business in IFRS jurisdictions is not applied as broadly). Although the proposed ASU would add implementation guidance to U.S. GAAP that is not found in IFRSs, the FASB intends to more closely align practice under U.S. GAAP with that under IFRSs by narrowing application of the U.S. GAAP definition. Further, the IASB has added a project on the definition of a business to its agenda and is considering making amendments similar to those in the proposed ASU.

Next Steps

Comments on the proposed ASU are due by January 22, 2016. An entity would apply the proposed amendments prospectively to any transaction that occurs on or after the effective date and would not be required to provide any disclosures at transition. The proposal notes that the FASB “will determine the effective date and whether the proposed amendments may be applied before the effective date after it considers stakeholder feedback on the proposed amendments.”

In addition, the Board has begun deliberations on the second phase of this project, which is intended to clarify whether transactions involving in-substance nonfinancial assets (either held directly or in a subsidiary) should be accounted for as acquisitions (or disposals) of nonfinancial assets or as acquisitions (or disposals) of businesses. The project is also intended to clarify the guidance on partial sales or transfers of assets that are within the scope of ASC 610-20 as well as the corresponding acquisition of partial interests in a nonfinancial asset or assets.

Thinking It Through

Both the current and proposed implementation guidance in ASC 805-10-55-4 state that a “business consists of inputs and processes applied to those inputs that have the ability to create outputs.” All businesses have inputs and processes, and most have outputs, but outputs are not required for a set to be a business. Further, ASC 805-10-55-5 states that “all of the inputs or processes that the seller used” in operating the set do not need to be part of the transaction. However, under the proposed ASU, “to be considered a business, the set must include, at a minimum, an input and a substantive process that together contribute to the ability to create outputs.” This is a change from the current guidance, under which a set meets the definition of a business if “market participants are capable of acquiring the [set] and continuing to produce outputs, for example, by integrating the [acquired set] with their own inputs and processes.”

Within the P&U industry, acquisitions of power plants and other generating assets (which are not considered in-substance real estate) were generally accounted for as business combinations under the current guidance. However, it is anticipated that under the proposed guidance, fewer acquisitions would qualify as business combinations.

Further, acquisitions such as those of proved gas reserves would need to be evaluated under the proposed guidance to determine whether the set includes a substantive process.

P&U entities should continue to monitor proposed amendments to the definition of a business and their potential effects on the industry.

For additional information about the proposed ASU, see Deloitte’s December 4, 2015, [Heads Up](#).

Classification of Certain Cash Receipts and Cash Payments in the Statement of Cash Flows

To reduce diversity in practice in the application of ASC 230, the FASB added the following nine issues related to the classification of cash flows to the EITF’s agenda in 2015 (addressed as part of EITF Issue No. 15-F):

- Issue 1 — Debt Prepayment or Debt Extinguishment Costs.
- Issue 2 — Settlement of Zero-Coupon Bonds.
- Issue 3 — Contingent Consideration Payments Made After a Business Combination.
- Issue 4 — Restricted Cash.
- Issue 5 — Proceeds from the Settlement of Insurance Claims.
- Issue 6 — Proceeds from the Settlement of Corporate-Owned Life Insurance Policies.
- Issue 7 — Distributions Received From Equity Method Investees.
- Issue 8 — Beneficial Interests in Securitization Transactions.
- Issue 9 — Predominant Cash Receipts and Cash Payments.

The EITF discussed all nine issues at its June 2015 and September 2015 meetings, reaching tentative decisions on eight of them (all issues except restricted cash). At its November 2015 meeting, the EITF reached a consensus-for-exposure on each of the eight issues previously discussed at the June 2015 and September 2015 meetings. While the EITF did not decide on the effective date, it decided that the guidance related to these eight issues would be applied retrospectively to all periods presented.¹³

¹³ The EITF decided to incorporate an impracticability exception, which would be applied in a manner similar to ASC 250-10-45-9.

In addition, the EITF continued redeliberating restricted cash (Issue 4), including issues related to the (1) definition of restricted cash, (2) classification of changes in restricted cash, and (3) presentation of cash payments and receipts that directly affect restricted cash. The EITF tentatively decided that changes in restricted cash would be classified as investing activities. At its March 2016 meeting, the EITF will continue to deliberate the other two issues related to restricted cash.

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 “Board’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.

Entity’s Decision Process

In September 2015, 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 were due by December 8, 2015.

Topic-Specific Disclosure Reviews

In addition to proposing amendments to guidance, the FASB staff is analyzing ways to “further promote [entities’] appropriate use of discretion” 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 “section-specific modifications.” In the second half of 2015, 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 for fair value measurement and income taxes are discussed below.

Fair Value Measurement

Objective for Disclosures

On December 3, 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 to establishing a disclosure objective, the Board has tentatively decided to make changes (i.e., eliminations, modifications, and additions) to the specific fair value disclosure requirements of ASC 820.

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 Board made the following tentative decisions that affect disclosures about Level 3 fair value measurements:

- *Valuation process* — 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 tentatively decided 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* — 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, the Board plans to 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* — 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.
- *Level 3 rollforward* — Retain the Level 3 rollforward requirement for PBEs. For entities that are not PBEs, the Board tentatively decided to modify the Level 3 rollforward guidance and remove the requirement to disclose the change in unrealized appreciation or depreciation 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 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 of Level 3 investments in a sentence rather than in a full rollforward as required today. A defined benefit plan sponsor 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 only be required to disclose transfers into and out of Level 3 and purchases of Level 3 assets in its defined benefit plan footnote (for more information about the FASB’s project on reviewing defined benefit plan disclosures, see the [project page](#) on Deloitte’s US GAAP Plus Web site).

Thinking It Through

The Board discussed the results of user outreach on the Level 3 rollforward and 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

PBEs 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 only required for the Level 3 amounts within net income under ASC 820-10-50-2(c) and (d). This requirement would not apply to entities that are not PBEs 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 ASU. Comments on the proposed ASU are due by February 29, 2016.

Income Taxes

At its meeting on January 7, 2015, the FASB staff outlined potential revisions to the disclosure requirements in ASC 740 that would enhance a financial statement user’s understanding of foreign taxes. The Board’s efforts are largely driven by [findings](#) in the post-implementation review of Statement 109 that users want more information that will allow them to (1) “analyze the cash effects associated with income taxes, particularly current period taxes paid by jurisdiction (e.g., U.S. and foreign), and estimate future tax payments”; and (2) “analyze earnings determined to be indefinitely reinvested in foreign subsidiaries.”

At its October 21, 2015, meeting, the FASB discussed income tax disclosure requirements related to income taxes paid, deferred income taxes, valuation allowances, and rate reconciliation and reached the following tentative decisions, which would apply to both public and nonpublic entities:

- *Income taxes paid* — The Board would add requirements for a reporting entity to disclose (1) when a change in tax law has been enacted and it is probable that the change will affect the reporting entity in a future period and (2) the disaggregation of the income taxes paid between foreign and domestic jurisdictions.
- *Deferred income taxes* — An entity would be required to disclose the balance sheet line item(s) in which deferred taxes are presented (i.e., a mapping of total deferred taxes to the balance sheet line items in which they are reported).
- *Valuation allowances* — An entity would need to explain the “nature and amounts of the valuation allowance recorded and released during the reporting period.”¹⁴
- *Rate reconciliation* — The Board tentatively decided that:
 - Nonpublic entities would be required to present a rate reconciliation in the notes to the financial statements, as ASC 740-10-50-12 currently requires for public entities.
 - A disaggregation of a component of the rate reconciliation would be required if the individual component is greater than or equal to 5 percent of the tax at the statutory rate in a manner consistent with SEC Regulation S-X.
 - An entity would be required to disclose a qualitative description of the items that have caused a significant year-over-year change to the effective tax rate.

In addition, the Board tentatively decided to require disclosures about the (1) gross amounts and expiration dates of carryforwards recorded on a tax return, (2) tax-effected amounts and expiration dates of carryforwards that give rise to a deferred tax asset (DTA), and (3) total amount of unrecognized tax benefits that offset DTAs related to carryforwards.

The Board directed its staff to begin drafting a proposed ASU for public comment that would take into account all the tentative decisions reached to date regarding income tax disclosure requirements. Such decisions include the Board’s previous tentative decisions made about disclosure requirements related to indefinitely reinvested foreign earnings and unrecognized tax benefits.

Undistributed Foreign Earnings

On February 11, 2015, the FASB tentatively decided that entities should:

- Disclose information separately about the domestic and foreign components of income before income taxes. Further, entities should separately disclose income before income taxes of individual countries that are significant relative to total income before income taxes.¹⁵
- Disclose the domestic tax expense recognized in the period related to foreign earnings.
- Disclose unremitted foreign earnings that, during the current period, are no longer asserted to be indefinitely reinvested and an explanation of the circumstances that caused the entity to no longer assert that the earnings are indefinitely reinvested. These disclosures should be provided in the aggregate and for each country for which the amount no longer asserted to be indefinitely reinvested is significant in relation to the aggregate amount.
- Separately disclose the accumulated amount of indefinitely reinvested foreign earnings for any country that is at least 10 percent of the aggregate amount.



¹⁴ Quoted text is from the FASB’s [summary](#) of tentative Board decisions reached at its October 21, 2015, meeting.

¹⁵ In ASC 740, income before income taxes is also referred to as pretax financial income.

Unrecognized Tax Benefits

At its [meeting](#) on August 26, 2015, the FASB tentatively decided to:

- Add a disclosure requirement in the tabular reconciliation to disaggregate settlements between cash and noncash (e.g., settlement by using existing net operating loss or tax credit carryforwards).
- Add a disclosure requirement to provide a breakdown 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.
- Eliminate the requirement in ASC 740-10-50-15(d) for entities to provide details of 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.

Since the two new proposed disclosure requirements for unrecognized tax benefits are related to the tabular reconciliation, they will only apply to public entities.

The Board directed its staff to prepare examples of the proposed additional disclosures.

Thinking It Through

While some of the FASB's proposed amendments to the current disclosure requirements for fair value measurement and income taxes 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.

Interim Reporting

To date, the FASB has discussed five interim reporting concepts under its proposed concepts statement. The Board generally agreed that interim financial statements should describe "differences in recognition, measurement, and presentation of line items" and should explain "how the interim period relates to the entire year."¹⁶ Two of the interim reporting concepts pertained to disclosing changes from the latest annual financial statements, and two pertained to disclosing items that are not peripheral or are "especially important."

To determine the meaning of "especially important," the Board will assess the interim disclosure requirements being proposed in the Board's project on reviewing fair value measurement disclosures as well as the interim disclosure requirements related to revenue in ASC 270-10-50-1A. On the basis of this process, the FASB can assess whether entities should disclose an item or amount that has not changed but is especially important.

Simplification Initiatives

Extraordinary Items

Introduction

On January 9, 2015, the FASB issued [ASU 2015-01](#), which eliminates from U.S. GAAP the concept of an extraordinary item. The Board released the new guidance as part of its simplification initiative, which, as explained in the ASU, is intended to "identify, evaluate, and improve areas of [U.S. GAAP] for which cost and complexity can be reduced while maintaining or improving the usefulness of the information provided to the users of financial statements."

¹⁶ Quoted text is from a [handout](#) for the Board's January 7, 2015, meeting.

Key Provisions of the ASU

To be considered an extraordinary item under existing U.S. GAAP, an event or transaction must be unusual in nature and must occur infrequently. Stakeholders often questioned the decision-usefulness of labeling a transaction or event as extraordinary and indicated that it is difficult to ascertain whether an event or transaction satisfies both criteria. In light of this feedback and in a manner consistent with its simplification initiative, the FASB decided to eliminate the concept of an extraordinary item. As a result, an entity will no longer (1) segregate an extraordinary item from the results of ordinary operations; (2) separately present an extraordinary item on its income statement, net of tax, after income from continuing operations; and (3) disclose income taxes and earnings-per-share data applicable to an extraordinary item. However, the ASU does not affect the reporting and disclosure requirements for an event that is unusual in nature or that occurs infrequently.

Effective Date and Transition

For all entities, the ASU is effective for annual periods beginning after December 15, 2015, and interim periods within those annual periods. Entities may apply the guidance prospectively or retrospectively to all prior periods presented in the financial statements. If an entity chooses to apply the guidance prospectively, it must disclose whether amounts included in income from continuing operations after adoption of the ASU are related to events and transactions previously recognized and classified as extraordinary items before the date of adoption. Early adoption is permitted if the guidance is applied as of the beginning of the annual period of adoption.

Debt Issuance Costs

Background

In April 2015, the FASB issued [ASU 2015-03](#), which changes the presentation of debt issuance costs in financial statements. Under the ASU, an entity presents such costs in the balance sheet as a direct deduction from the related debt liability rather than as an asset. This treatment is consistent with the presentation of debt discounts under U.S. GAAP. Under previous guidance, an entity reported debt issuance costs in the balance sheet as deferred charges (i.e., as an asset). Amortization of the costs is reported as interest expense.

The amendments do not affect the current guidance on the recognition and measurement of debt issuance costs. For example, the costs of issuing convertible debt would not change the calculation of the intrinsic value of an embedded conversion option that represents a beneficial conversion feature under ASC 470-20-30-13. Thus, entities may still need to track debt issuance costs separately from a debt discount.

Revolving Debt Arrangements

Since the ASU's issuance, questions were raised regarding (1) the appropriate balance sheet presentation of costs incurred in connection with revolving-debt arrangements and (2) whether such costs are within the ASU's scope. At the EITF's June 18, 2015, meeting, it was confirmed that those costs are not within the scope of ASU 2015-03, and the SEC staff announced that it would "not object to an entity deferring and presenting [such] costs as an asset and subsequently amortizing the . . . costs ratably over the term of the line-of-credit arrangement." That announcement was codified in August 2015 by the issuance of [ASU 2015-15](#).

See Deloitte's June 18, 2015, [Heads Up](#) for additional information about ASU 2015-03, including further considerations of the treatment of costs associated with revolving-debt arrangements.

Effective Date and Transition

For PBEs, the guidance in ASU 2015-03 is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2015. For entities other than PBEs, the guidance is effective for fiscal years beginning after December 15, 2015, and interim periods beginning after December 15, 2016. Early adoption is allowed for all entities for financial

statements that have not been previously issued. Entities would apply the new guidance retrospectively to all prior periods (i.e., the balance sheet for each period is adjusted).

The ASU requires an entity to “disclose in the first fiscal year after the entity’s adoption date, and in the interim periods within the first fiscal year, the following:

1. The nature of and reason for the change in accounting principle
2. The transition method
3. A description of the prior-period information that has been retrospectively adjusted
4. The effect of the change on the financial statement line item (that is, the debt issuance cost asset and the debt liability).”

Simplifying the Measurement of Inventory

On July 22, 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).

Background

The project on simplifying the subsequent measurement of inventory is part of the FASB’s simplification initiative. Launched in June 2014, the simplification initiative is intended to improve U.S. GAAP by reducing costs and complexity while maintaining or enhancing the usefulness of the related financial statement information. Simplification projects are narrow in scope, involve limited changes to U.S. GAAP, and can be completed quickly.

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 PBEs, 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 thereafter. Early application of the ASU is permitted. Upon transition, entities must disclose the nature of and reason for the accounting change.

Simplifying the Accounting for 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

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.

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 PBEs, the ASU is effective for fiscal years beginning after December 15, 2015, including interim periods within those fiscal years. 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.

For more information about the ASU, see Deloitte's September 30, 2015, [Heads Up](#).

Income Taxes Simplification Projects

On January 22, 2015, the FASB issued an [ED](#) of two proposed ASUs, one on intra-entity asset transfers and the other on balance sheet classification of deferred taxes, in an effort to simplify the accounting for income taxes.

Intra-Entity Asset Transfers

Under existing guidance, ASC 740-10-25-3 prohibits an entity from recognizing current and deferred income tax consequences of an intra-entity asset transfer until the entity sells the asset(s) to an outside party. The proposed ASU on intra-entity asset transfers would eliminate this prohibition and would require recognition of the income tax consequences upon transfer.

At its October 2015 meeting, the FASB redeliberated the proposed ASU on the basis of comment letters received from respondents. A number of constituents asserted that both costs and complexity would increase under this proposal. Some respondents proposed that the Board permit a practical expedient to continue the exception for intra-entity transfers of inventory while eliminating the exception for transfers of all other assets. The Board instructed its staff to perform additional research on these issues as well as outreach regarding the costs and benefits of a practical expedient for intra-entity inventory transfers. The Board will redeliberate the proposal at a future meeting and is expected to either eliminate the exception entirely (in a manner consistent with the current proposal) or establish the practical expedient, in which case the exception would be eliminated for all intra-entity asset transfers other than inventory.

For additional information about the proposed ASU, see Deloitte's January 30, 2015, *Heads Up*.

Balance Sheet Classification of Deferred Taxes

On November 20, 2015, the FASB issued [ASU 2015-17](#), which requires entities to present DTAs and 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.

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.

For PBEs, the ASU will be effective for annual periods beginning after December 15, 2016, and interim periods within those years. For entities other than PBEs, 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. Therefore, the ASU can be adopted by all entities 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 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.

Simplifying the Accounting for Employee Share-Based Payments

At its November 2015 meeting, the FASB redeliberated its [proposed ASU](#) on share-based payments as part of its simplification initiative. As a result of the redeliberations, the Board directed its staff to draft a final ASU for a vote by written ballot.

The final ASU will affect various aspects of the accounting for employee share-based payment transactions for both public and nonpublic entities, including the accounting for income taxes (e.g., the accounting related to excess tax benefits and deficiencies), forfeitures, minimum statutory withholding requirements, and classification in the statement of cash flows. In addition, the final ASU will contain two practical expedients for nonpublic entities under which such entities can use the simplified method to estimate the expected term of an award and make a one-time election to switch from fair value measurement to intrinsic value measurement for liability-classified awards. During its deliberations, the Board decided not proceed with its proposal to simplify the classification of awards with repurchase features. The Board noted that this issue may be addressed in the future as part of a project to distinguish equity from liabilities.

For public entities, the guidance in the upcoming ASU will be effective in annual reporting periods beginning after December 15, 2016, and interim periods within those reporting periods.

For nonpublic entities, such guidance will be effective in annual reporting periods beginning after December 15, 2017, and interim periods within annual 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 are not available to be issued. Issuance of the final ASU is expected in the first quarter of 2016.

For additional information about the proposed ASU and the Board's redeliberations, see Deloitte's June 12, 2015, [Heads Up](#) and its November 30, 2015, [journal entry](#).

Balance Sheet Classification of Debt

Background

This project is part of the FASB's simplification initiative. The objective of the project, as described in the Board's July 29, 2015, meeting [handout](#), is "to replace existing, fact-pattern-specific debt classification guidance with an overarching, cohesive principle to reduce cost and complexity for preparers and auditors when determining whether debt should be classified as current or noncurrent on the balance sheet, while improving the usefulness of the information reported to financial statement users."

The handout notes that at the FASB's January 28, 2015, meeting, the Board tentatively agreed on a classification approach under which an entity would "classify debt as noncurrent if one or both of the following criteria are met as of the balance sheet date:

- (a) The liability is contractually due to be settled more than 12 months (or operating cycle, if longer) after the balance sheet date.
- (b) 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."

Key tentative decisions made at the July 29, 2015, meeting are discussed below.

Scope

The proposed classification approach applies to debt arrangements that, as described in the meeting handout, "provide a lender a contractual right to receive money and a borrower a contractual obligation to pay money on demand or on fixed or determinable dates."

At its July 29, 2015, meeting, the Board tentatively decided to clarify that the approach applies to both (1) convertible debt (even though such instruments may be settled in shares) and (2) mandatorily redeemable financial instruments classified as liabilities under ASC 480-10 (even if such instruments are in the form of equity shares).

Waiver of Debt Covenant Violations

Under the Board's proposed classification approach, the determination of whether debt is current or noncurrent is made on the basis of the facts and circumstances that exist as of the balance sheet date. This proposal differs from current U.S. GAAP, under which an entity is permitted to consider certain post-balance-sheet events, such as a post-balance-sheet-date arrangement to refinance a short-term obligation on a long-term basis.

At its July 29, 2015, meeting, the Board tentatively decided to make one exception to its proposed approach. When a debtor violates a debt covenant on or before the balance sheet date and the long-term debt becomes a short-term obligation, it should not automatically be required to classify the debt as current. If the lender grants the debtor a waiver of the covenant before the debtor's financial statements are issued, the debtor would present the debt separately within long-term debt on the face of the balance sheet. The purpose of such presentation would be to notify financial statement users that such debt is classified as noncurrent even though the debtor violated one or more covenants as of the balance sheet date. The exception would not apply to waivers that involve a debt modification or extinguishment.

Further, the Board tentatively decided to retain existing U.S. GAAP guidance (ASC 470-10-45-1(b)) requiring that (1) the waiver of the current violation be for at least 12 months from the balance sheet date and (2) it is *not* probable that the borrower will be unable to comply with the covenant by the covenant compliance dates within the next 12 months.

Subjective Acceleration Clauses

Under the Board's proposed classification approach, debt that is callable by the creditor or due on demand is classified as current. During the Board's discussion on January 28, 2015, the staff suggested that debt subject to subjective acceleration clauses (SACs) would also be classified as current under the proposed classification approach.

However, at its July 29, 2015, meeting, the Board tentatively decided that SACs should affect classification only when triggered (in a manner similar to the treatment of debt covenant violations). Accordingly, a long-term obligation would be classified as noncurrent even if it is subject to an SAC. This decision differs from current U.S. GAAP, under which long-term obligations subject to SACs are sometimes classified as current (e.g., because of recurring losses or liquidity problems).

Disclosure and Transition

The Board tentatively decided to incorporate into U.S. GAAP the disclosure requirements related to debt covenant violations in SEC Regulation S-X, Rule 4-08 (ASC 235-10-599-1(c)). Thus, such disclosures would be required for both public and nonpublic business entities. The Board also tentatively decided to require entities to disclose the nature and existence of significant SACs and debt covenants.

In addition, the Board tentatively decided to require prospective transition and that the transition disclosure requirements should be consistent with the applicable disclosure requirements in ASC 250-10-50. The effective date of the proposed guidance will be determined after the comment period.

Next Steps

The Board directed the staff to proceed with drafting a proposed ASU for a vote by written ballot. The proposed ASU will have a 60-day comment period.

Simplifying the Equity Method of Accounting

In June 2015, the FASB issued a [proposed ASU](#) on equity method accounting as part of its simplification initiative. The proposal aimed to eliminate the requirements for an investor to (1) account for the basis differences related to its equity method investees and (2) retroactively account for an investment that becomes newly qualified for use of the equity method because of an increase in ownership interest or degree of influence.

On the basis of the feedback received on its proposed ASU, the FASB directed the staff to perform additional research on whether to eliminate the requirement to account for the basis differences. However, the FASB decided to further clarify and finalize its proposed guidance related to eliminating the retroactive accounting for an investment that becomes newly qualified for use of the equity method of accounting upon an increase in ownership interest or degree of influence. The FASB clarified that unrealized holding gains or losses in accumulated other comprehensive income related to an available-for-sale security that becomes eligible for the equity method should be recognized in earnings as of the date on which the investment qualifies for the equity method.

The FASB directed the staff to draft a final standard for issuance, which is expected in the first quarter of 2016. The guidance in the ASU will be applied prospectively to increases in the level of ownership interest or degree of influence occurring after the final ASU's effective date. No transition disclosures will be required. For all entities, the final standard will be effective for fiscal years beginning after December 15, 2016, including interim periods within those fiscal years. In addition, all entities will be permitted to early adopt the guidance upon issuance of the final standard.

Accounting Alternatives for Private Companies

Background

The following guidance, developed by the Private Company Council (PCC), was issued in 2014:

- *Goodwill* — In January 2014, the FASB issued [ASU 2014-02](#), which allows private companies to use a simplified approach to account for goodwill after an acquisition. Under such approach, an entity would (1) amortize goodwill on a straight-line basis, generally over 10 years; (2) test goodwill for impairment only when a triggering event occurs; and (3) make an accounting policy election to test for impairment at either the entity level or the reporting-unit level. The ASU also eliminates “step 2” of the goodwill impairment test; as a result, an entity would measure goodwill impairment as the excess of the entity’s (or reporting unit’s) carrying amount over its fair value. An entity that elects the simplified approach should adopt the ASU’s guidance prospectively and apply it to all existing goodwill (and any goodwill arising from future acquisitions) existing as of the beginning of the period of adoption. The ASU is effective for annual periods beginning after December 15, 2014, and interim periods with annual periods beginning after December 15, 2015. See Deloitte’s January 27, 2014, [Heads Up](#) for more information.
- *Hedge accounting* — In January 2014, the FASB issued [ASU 2014-03](#), which gives private companies a simplified method of accounting for certain receive-variable, pay-fixed interest rate swaps used to hedge variable-rate debt. An entity that elects to apply the simplified hedge accounting to a qualifying hedging relationship would continue to account for the interest rate swap and the variable-rate debt separately on the face of the balance sheet. However, the entity would be able to assume no ineffectiveness in the hedging relationship, thereby essentially achieving the same income statement profile as with a fixed-rate borrowing expense. In addition, the entity is allowed more time to complete its initial hedge documentation. An entity that applies the simplified approach also may elect to measure the related swap at its settlement value rather than at fair value. The ASU is effective for annual periods beginning after December 15, 2014, and interim periods within annual periods beginning after December 15, 2015. Entities that elect the simplified approach should adopt the ASU under either a full retrospective or a modified retrospective method. See Deloitte’s January 27, 2014, [Heads Up](#) for more information.
- *Intangibles* — In December 2014, the FASB issued [ASU 2014-18](#), which gives private companies an exemption from having to recognize certain intangible assets for (1) assets acquired in a business combination or (2) investments accounted for under the equity method or upon the adoption of fresh-start accounting. Specifically, an entity would not be required to separately recognize intangible assets for noncompete agreements and certain

customer-related intangible assets that arise within the scope of the ASU. Because the amounts associated with these items would be subsumed into goodwill, an entity that elects this accounting alternative would also be required to adopt ASU 2014-02 (see discussion above), resulting in the amortization of goodwill. Entities that elect the alternative should adopt the ASU prospectively to the first eligible transaction within the scope of the ASU that occurs in the annual period beginning after December 15, 2015 (with early adoption permitted), and all transactions thereafter. See Deloitte’s December 30, 2014, *Heads Up* for more information.

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

In September 2015, the FASB issued for public comment a [proposed ASU](#) that would give private companies a one-time unconditional option to forgo a preferability assessment the first time they elect a PCC accounting alternative within the proposal’s scope. It would also eliminate the effective dates of PCC accounting alternatives that are within the proposal’s scope as well as extend the transition guidance in ASU 2014-02 and ASU 2014-03. The proposal’s amendments could affect all private companies within the scope of ASUs 2014-02 and 2014-03 as well as ASU 2014-07 and ASU 2014-18. See Deloitte’s October 6, 2015, *Heads Up* for more information.

Other Private-Company Matters

Throughout 2015, the PCC has discussed aspects of financial reporting that are complex and costly for private companies, including stock-based compensation, the application of VIE guidance to nonleasing common-control arrangements, and the balance sheet classification of debt.

The PCC also asked the FASB staff to research (1) examples that would clarify the application of VIE guidance to nonleasing common-control arrangements and (2) potential modifications to existing business scope exceptions to address application issues. The classification of debt will be discussed at a future meeting.

In addition, the PCC decided in February 2015 that it would not “amend the existing definitions of a nonpublic entity at this time. The existing definitions will remain in the FASB Codification until potentially amended at a later date by the FASB. The definition of a public business entity, [as amended by ASU 2013-12,] should continue to be used for future accounting and reporting guidance.”¹⁷



¹⁷ See the PCC’s [overview](#) of decisions reached on PCC Issue No. 14-01.

Section 6

Implications of the New Revenue Model

Background

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

The FASB recently issued [ASU 2015-14](#), which defers the effective date of ASU 2014-09 by one year for all entities reporting under U.S. GAAP and permits early adoption as of the original effective dates. Refer to [Effective Date and Transition](#) below for further discussion of the effective date. In addition, in response to feedback received by the FASB-IASB joint revenue recognition transition resource group (TRG), the FASB is considering certain revisions to the guidance in the new revenue standard (as is the IASB, which has proposed revisions of its own in its July 2015 [ED](#)). Those contemplated revisions are discussed in three proposed ASUs:

- *Narrow-Scope Improvements and Practical Expedients* — Issued on September 30, 2015, this [proposed ASU](#) would (1) clarify how to assess whether collectibility of consideration to which an entity is entitled is probable under certain circumstances, (2) add a practical expedient permitting sales taxes to be presented on a net basis in revenue, (3) clarify how to account for noncash consideration at contract inception and throughout the contract period, and (4) add a practical expedient to facilitate how to assess the impact of historical contract modifications upon transition. See Deloitte’s October 2, 2015, [Heads Up](#) for more information.
- *Principal Versus Agent Considerations (Reporting Revenue Gross Versus Net)* — Issued on August 31, 2015, this [proposed ASU](#) seeks to address 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 proposed ASU attempts to clarify (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 ASC 606’s general control principle. In addition, the proposed ASU would clarify 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 September 1, 2015, [Heads Up](#) for more information.
- *Identifying Performance Obligations and Licensing* — Issued on May 12, 2015, this [proposed ASU](#) aims to clarify the new revenue standard’s guidance on an entity’s identification of certain performance obligations. The proposal would add guidance on immaterial promised goods and services and separately identifiable promises. Other proposed amendments include (1) a policy election for shipping and handling fees incurred after control of a good is transferred to a customer and (2) clarifications related to licenses. See Deloitte’s May 13, 2015, [Heads Up](#) and its October 8, 2015, [journal entry](#) for more information.

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

Key Accounting Issues

Although ASU 2014-09 and related proposed amendments may not significantly change how P&U entities typically recognize revenue, certain requirements of the ASU may require a change from current practice. Discussed below are some key provisions of the ASU that may affect P&U entities as well as how the guidance might be considered in some typical transactions.

Thinking It Through

To help P&U entities implement the ASU, the FASB and IASB created their joint TRG on revenue recognition and the AICPA assembled a P&U industry task force.² In addition, the AICPA is currently developing an accounting guide on revenue recognition. See Deloitte's *TRG Snapshot* publications for information about the topics discussed to date by the TRG.

Tariff Sales of a Regulated Utility

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

One of the issues that the P&U industry task force has reviewed is whether sales to tariff-based customers are within the scope of the ASU. If such sales are deemed to be within the ASU's scope, it will be necessary to determine the term of the contractual relationship between the utility and each customer as well as any rights or obligations either party has under the contract. The P&U industry task force has discussed this issue with the AICPA's revenue recognition working group (the "RRWG") and also discussed it with FinREC in January 2016.

Thinking It Through

Our view, generally, is that tariff sales would be within the scope of the ASU if they do not otherwise meet the criteria to be alternative revenue programs under ASC 980-605-25-4. This is consistent with the consensus view reached by the P&U industry task force and validated through discussions with the RRWG. 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.

Contract Modifications

P&U entities should consider how they are affected by the ASU'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 was not modified and account for the additional goods or services provided in the modification as a "new" contract.

² Deloitte is represented on both the TRG and the AICPA task force.

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

As previously discussed, on September 30, 2015, the FASB issued a proposed ASU that would add a practical expedient to facilitate how to evaluate historical contract modifications at transition. The proposed ASU would also define 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, extension-period rate 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 stand-alone selling 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

P&U entities should carefully evaluate the facts and circumstances related to a B&E contract modification to determine whether it should be accounted for as a new contract (which may include a significant financing component) or as a prospective contract modification. A contract modification is treated as a new contract when distinct goods or services are added to the contract and the additional consideration reflects the stand-alone selling price of those additional goods or services. For B&E contract modifications, stakeholders have questioned how the payment terms affect the evaluation of whether the contract should be accounted for as a modification or as a separate contract. That is, there has been uncertainty about whether entities should compare (1) the price the customer will pay for *those* added goods or services (i.e., the blended price paid for the goods or services delivered during the added contract period) with the stand-alone selling price of those goods or services or (2) the total increase in the aggregated contract price with the stand-alone selling price of the added goods or services.

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 price for the remainder of the combined term. The P&U industry task force was unable to reach a consensus on whether a B&E contract modification should be accounted for as (1) a separate contract or (2) the termination of an existing contract and the creation of a new contract. The issue was discussed with the RRWG, and it was agreed that the issue should be elevated to the TRG in the second half of 2015. However, the TRG did not discuss this issue at its November 2015 meeting, and it is unclear whether the TRG will address the issue in the future. We understand that if the TRG does not address the issue, the FASB staff will provide guidance through a technical inquiry.

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. The P&U industry task force has been asked to address the accounting considerations related to such a transaction. Specifically, the task force is addressing 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.

Commodity Exchange Arrangements

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

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

Thinking It Through

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

Distinct Performance Obligations

The ASU provides guidance on evaluating the promised "goods or services"³ 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."

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

Under the ASU, a series of distinct goods or services has the same pattern of transfer if both of the following criteria are met: (1) each distinct good or service in the series meets the criteria for recognition over time and (2) the same measure of progress is used to depict performance in the contract. Therefore, a simple forward sale of electricity 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.

Stakeholders have raised questions regarding the determination of when an entity transfers control of a commodity. Specifically, they have questioned whether long-term contracts to deliver commodities that are not always immediately consumed by the customer (e.g., coal or natural gas, which, unlike electricity, can be efficiently stored for a later use) could be accounted for as a series and, therefore, a single performance obligation that is satisfied over time. The TRG discussed aspects of this issue at its July 2015 meeting, during which TRG members generally agreed with the FASB and IASB staffs' conclusion that an entity should consider "all relevant facts and circumstances, including the inherent characteristics of the commodity, the contract terms, and information about infrastructure or other delivery mechanisms." However, the TRG did not specifically address application of the series guidance to storable commodities. The P&U industry task force has developed a position on this matter that seeks to allow the application of the series guidance to storable commodities in certain scenarios and will be sharing this position with the RRWG in early 2016 for the working group's consideration.

Variable Pricing

The ASU requires that variable consideration be included in the transaction price under certain circumstances. An estimate of variable consideration is only included in the transaction price to the extent that it is probable⁴ that subsequent changes in the estimate would not result in a "significant reversal" of revenue. This concept is commonly referred to as the "constraint." The ASU requires entities to perform a qualitative assessment that takes into account the likelihood and magnitude of a potential revenue reversal and provides factors that could indicate that an estimate of variable consideration is subject to significant reversal (e.g., susceptibility to factors outside the entity's influence, long period before uncertainty is resolved, limited experience with similar types of contracts, practices of providing concessions, or a broad range of possible consideration amounts). This estimate would be updated in each reporting period to reflect changes in facts and circumstances.

The use of variable consideration (e.g., index or formula-based pricing) may present challenges related to estimating and allocating the transaction price and applying the ASU's constraint guidance. For example, a P&U entity may have a multiyear contract to sell a fixed quantity of electricity each hour at a price derived from a formula, 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 only account for the optional purchases once the options are exercised. The TRG

⁴ "Probable" in this context has the same meaning as in ASC 450-20: "the event or events are likely to occur." In IFRS 15, the IASB uses the term "highly probable," which has the same meaning as the FASB's "probable."

addressed the issue of optional purchases at its November 2015 meeting, and the P&U industry task force will be preparing an analysis of the implications of the TRG's views for energy companies in early 2016.

Thinking It Through

A contract may include various types of consideration. In some cases, an entity may need to use significant judgment in estimating certain variable amounts (e.g., amounts based on wind generation). In other instances, amounts may vary in total but include potential minimum fees or charges that are fixed. When evaluating the constraint in such cases, an entity would determine the significance of the potential revenue reversal by comparing the potential reversal with the total consideration (including both fixed and variable consideration). The larger the fixed consideration is in proportion to the total consideration, the greater the likelihood that variable consideration would not create the potential for a "significant" reversal (i.e., the estimate would not be "constrained" and would therefore be included in the transaction price).

Power Purchase Agreements

PPAs typically give the power purchaser the right, over the term of the contract, to buy from the 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 ASU 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). We expect the P&U industry task force to address this topic and make implementation recommendations. It is generally expected that deliveries under strip-price contracts will be recognized at the contract price (i.e., will not give rise to embedded financing elements). P&U entities will need to consider this approach when assessing contracts with other pricing conventions (e.g., step-price arrangements). The P&U industry task force is discussing the appropriate revenue profile for strip- and step-price arrangements with the RRWG and expects to provide guidance on this topic to help preparers and auditors.

Thinking It Through

PPAs commonly include a combination of fixed and variable pricing and/or provide for volume variability based on contingent factors. When implementing the ASU, P&U entities should carefully consider existing and future PPAs to determine whether they contain such complex terms, which may make it more difficult for the entities to apply the new revenue model to determine the transaction price and measure progress toward satisfying performance obligations.

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

- The customer simultaneously receives and consumes the benefits of each distinct delivery (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 RECs. Companies regularly enter into transactions in which such items as energy, RECs, and capacity are bundled together in a single contract, often with one transaction price.

Scope Considerations

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

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

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

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

Identifying the Performance Obligation(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 ASU, a performance obligation is distinct if it meets both of the following criteria in ASC 606-10-25-19:

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

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

Recognizing Revenue When (or as) Performance Obligations Are Satisfied

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

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

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

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

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

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

If delivery of RECs is deemed to be a distinct performance obligation, the P&U entity would need to appropriately consider the manner that best depicts the transfer of the RECs to the off-taker as it determines when it has satisfied the distinct performance obligation to deliver the certificates. If the title of the certificate is not transferred when the energy is sold (e.g., as a result of certification lag), control of the certificates may not have yet been transferred to the off-taker. Thus, revenue from the RECs may not be recognized contemporaneously with the delivery of the associated electricity. On the other hand, since the seller has fulfilled all of its obligations with respect to the REC, it may be concluded that revenue for the REC should be recognized upon delivery of the electricity. The P&U industry task force is specifically addressing the appropriate analysis of REC sales in this regard.

Thinking It Through

Some entities have historically concluded that while the transfer of the title to RECs may lag behind the selling of the energy, certification is perfunctory after generation of the energy is complete and the patterns of revenue recognition for RECs should therefore match those for the energy. Entities may need to revisit this practice when adopting the ASU since the perfunctory notion was not carried forward in the new revenue guidance. The P&U industry task force therefore plans to address the issue of separating RECs and the related revenue recognition timing.

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 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. That is, 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 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. This issue was added to the task force's agenda in the second half of 2015; as of the release of this publication, a consensus on the matter has not been reached.

Sales of Power-Generating Property, Plant, and Equipment

P&U entities often enter into arrangements that include the full or partial sale of power-generating PP&E (e.g., transactions involving the sale of all or a part of power plants, solar farms, and wind farms). Under current 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-Substance Nonfinancial Assets

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

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

Thinking It Through

The ASU's consequential amendments eliminate the guidance in ASC 360-20 on sales of real estate. Entities will therefore need to apply the new guidance in ASC 606 and ASC 610-20 on sales or transfers of nonfinancial assets (including real estate). See Deloitte's July 2, 2014, *Heads Up* for additional information, including considerations related to evaluating various forms of continuing involvement.

Accounting for Partial Sales

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

The FASB is currently evaluating its guidance on partial sales or transfers of nonfinancial assets as part of its project to clarify the definition of a business. However, if the FASB does not complete this project by the time the ASU becomes effective, diversity in practice may evolve since entities may apply different approaches to determine how to account for partial sales of nonfinancial assets in accordance with the ASU. The P&U industry task force is monitoring the FASB's progress on this matter and will address partial sales if necessary to mitigate such diversity.

Disclosures

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

- Presentation or disclosure of revenue and any impairment losses recognized separately from other sources of revenue or impairment losses from other contracts.
- A disaggregation of revenue to "depict how the nature, amount, timing, and uncertainty of revenue and cash flows are affected by economic factors" (the ASU also provides implementation guidance).
- Information about contract assets and liabilities (including changes in those balances) and the amount of revenue recognized in the current period that was previously recognized as a contract liability and the amount of revenue recognized in the current period that is related to performance obligations satisfied in prior periods.
- Information about performance obligations (e.g., types of goods or services, significant payment terms, typical timing of satisfying obligations, and other provisions).
- Information about an entity's transaction price allocated to the remaining performance obligations, including (in certain circumstances) the "aggregate amount of the transaction price allocated to the performance obligations that are unsatisfied (or partially unsatisfied)" and when the entity expects to recognize that amount as revenue.
- A description of the significant judgments, and changes in those judgments, that affect the amount and timing of revenue recognition (including information about the timing of satisfaction of performance obligations, the determination of the transaction price, and the allocation of the transaction price to performance obligations).
- Information about an entity's accounting for costs to obtain or fulfill a contract (including account balances and amortization methods).
- Information about the policy decisions (i.e., whether the entity used the practical expedients for significant financing components and contract costs allowed by the ASU).

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

Effective Date and Transition

The 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 ASU 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 ASU:

- *Full retrospective application* — Retrospective application would take into account the requirements in ASC 250 (with certain practical expedients). Under this approach, entities would need to reevaluate their contracts from inception to determine the income recognition pattern that best depicts the transfer of goods and services. Further, for comparative financial statement purposes, public entities with a calendar year-end would be required to present income under the new revenue model beginning on January 1, 2016.

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

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

	2018	2017	2016
Initial Application Year	Current Year	Prior Year	Prior Year 2
New contracts	New ASU		
Existing contracts	New ASU + cumulative catch-up	Legacy GAAP	Legacy GAAP
Completed contracts		Legacy GAAP	Legacy GAAP

⁵ At the 2015 AICPA Conference on Current SEC and PCAOB Developments, the Division staff provided a reminder that it will accept less than five years of revenue presented on the basis of the new revenue standard in selected financial data (i.e., it will not require a registrant to retrospectively adjust the last two years). In doing so, the staff is encouraging registrants to use the full retrospective method of adoption because that method will yield information that is more helpful to financial statement users.

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 ASU 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 ASU and determine the transition approach that is practical to apply and most beneficial to financial statement users.

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 2015 AICPA Conference on Current SEC and PCAOB Developments, the SEC staff weighed in on the SAB Topic 11.M disclosure requirements specific to the new revenue recognition standard. While acknowledging that registrants may not have fully evaluated the implications of the new revenue recognition standard, the staff provided a reminder that SAB Topic 11.M requires registrants to disclose their conclusions to date regarding the impact of the new revenue standard, such as the planned adoption date. The staff expects the level of disclosures to increase as the effective date of the new revenue standard approaches.

Thinking It Through

Given the ongoing standard setting related to implementation of the new revenue standard and the number of outstanding implementation issues being addressed by the industry, we would not expect P&U companies to be in a position to provide specific information about the effects of adoption in their SAB Topic 11.M disclosures in 2015 Forms 10-K. Regulators and others are generally aware of the work being done by the industry task forces (including progress of the task forces), and we expect that they will accept limited SAB Topic 11.M disclosures given the uncertainty about implementation that still exists.



Section 7

Overview of the New Leases Model

Background

After almost a decade, the FASB and IASB are nearing the end of their journey toward enhancing lease accounting: the IASB issued its final standard, IFRS 16, on January 13, 2016, and the FASB is expected to issue its final ASU shortly (i.e., in February 2016). One of the primary objectives of the leases project is to address the current off-balance-sheet financing concerns related to a lessee's operating leases. While developing an approach that would require all operating leases to be recorded on the balance sheet may seem like a simple task, the numerous EDs issued by the boards, along with years of redeliberations, have proved that it has been anything but easy. The boards have had to grapple with questions 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 subsequently account for the amounts recorded (a point on which the FASB and IASB were unable to converge), and (4) how to perform these assessments in a cost-effective manner.

In addition, the boards have addressed other concerns related to the current almost-40-year-old leases model. For example, the FASB is proposing to eliminate the bright lines currently in U.S. GAAP for determining lease classification, and both boards are proposing that lessors provide additional transparency into their exposure to the changes in value of their residual assets and how they manage that exposure.

The following discussion is based on our understanding of the deliberations to date and our expectations of the content of the final standard. As of the date of this publication, the final U.S. GAAP standard had not been issued. Therefore, some of the content herein may be subject to change. In addition, we expect the P&U industry to address a variety of implementation issues once the final standard is issued, and some of the thinking included below may be affected.

Key Provisions

Scope

The scope of the lease accounting guidance would not be restricted to leases of property, plant, and equipment, as it is today. Rather, the scope of the new guidance would include all leases of assets except (1) leases of intangible assets, (2) leases to explore for or use minerals, oil, natural gas, and similar nonregenerative resources, and (3) leases of biological assets. As a result, assets currently accounted for as inventory, such as spare parts and supplies, may now be subject to a lease under the new guidance.

Thinking It Through

We understand through recent discussions with the FASB staff that the scope of the FASB guidance may be changed to exclude inventory and CWIP. This reconsideration occurred late in the process as the FASB received unsolicited feedback about revising the scope, particularly in the context of build-to-suit arrangements. Interested parties should refer to the final standard for final resolution of this matter.

Definition of a Lease

The new standard will define a lease as "a contract, or part of a contract, that conveys the right to control the use [of] an identified asset (the underlying asset) for a period of time in exchange for consideration." When determining whether a contract contains a lease under the new standard, entities should assess whether (1) performance of the contract depends on the use of an identified asset and (2) the customer obtains the right to control the use of the identified asset for a particular period.

The concept of an identified asset is mostly consistent with that in current U.S. GAAP and IFRSs. Under this concept, a leased asset must be specifically 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). The evaluation should take into account any substantive rights of the supplier to substitute the underlying asset throughout the period of use. Substitution rights would

be considered substantive if the supplier has the practical ability to substitute alternative assets (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 would benefit economically from the substitution. A specified asset could be a physically distinct portion of a larger asset (e.g., one floor of a building). However, a capacity portion of a larger asset that is not physically distinct (e.g., a percentage of a natural gas pipeline's or storage facility's total capacity) would generally not be a specified asset unless that capacity portion reflects substantially all of the larger asset's overall capacity.

Thinking It Through

The requirement that 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.

With regard to a customer's right to control the use of the identified asset, the definition of a lease under the new standard will represent a significant change from current guidance. Under existing U.S. GAAP, taking substantially all of the outputs of an identified asset is considered indicative of the customer's right to control the use of that asset if the pricing per unit in the arrangement is neither fixed nor market at the time of delivery (e.g., a power purchase agreement in which the off-taker purchases substantially all of the outputs of a generating asset). In contrast, the new standard will align the assessment of whether a contract provides the customer the right to control the use of the specified asset with the concept of control developed as part of the boards' new revenue standard.¹ Accordingly, a contract evaluated under the new standard would be deemed to convey the right to control the use of an identified asset if the customer has 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 benefit that the customer can realize in a transaction with a third party (e.g., renewable energy credits).

Implications for P&U Entities

Agreements that P&U entities enter into are frequently customized and include services and other components critical to completing the contract. P&U entities not electing the transition practical expedient will need to assess many current service and lease contracts under the new leases standard to determine whether such agreements meet, or have components that meet, the new definition of a lease. Under the standard, when determining whether a contract contains a lease, P&U entities would assess whether (1) performance of the contract depends on the use of an identified asset and (2) the customer obtains the right to control the use of the identified asset for a particular period.

Power Purchase Agreements

Under current guidance, a power purchase agreement (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 proposed 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 would not be considered a lease solely on the basis of the pricing, and the extent, of outputs purchased under the contract. Rather, P&U entities would 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.

¹ ASU 2014-09, *Revenue From Contracts With Customers* (codified in ASC 606) defines control as "the ability to direct the use of, and obtain substantially all of the remaining benefits from, the asset." This differs from the concept of control in the consolidation guidance, which requires the design of the entity to be considered in the evaluation of control.

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 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 generation given the limited number of strategic decisions about generating assets that are made during the commercial operations phase.

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 following table 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 (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 over those activities do not by themselves most affect how and for what purpose the generating asset is used; rather, they are <i>subject to</i> 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.

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 involvement in design will be one of the most significant judgment areas under the new standard and will be particularly relevant for arrangements involving renewable generating assets. Since 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. O&M is typically performed by the asset owner (the supplier), but design will often be a more difficult assessment given different levels of influence that an off-taker may have over various decisions (e.g., siting, determining the technology to be used). An entity will need to use judgment when performing this evaluation. Off-takers should also consider the impact of curtailment rights in the above analysis and consider whether those rights convey the right to direct the use of the asset.

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, by which the operator must strictly abide.

In all scenarios, the off-taker would need 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 would 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 boards have not proposed a specific definition of "economic benefits," the term as used in the new standard would encompass 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 would conclude that certain other benefits provided in a PPA (e.g., capacity, renewable energy credits, or steam) may constitute economic benefits. An off-taker would have to consider whether the receipt or nonreceipt of such additional benefits from the use of a facility affects the accounting for a particular

contract or contractual component as a lease. It is important to note that tax attributes related to the ownership of the asset would not be considered economic benefits.

Transportation and Storage Contracts

Contracts to transport or store gas or other fuel products would need to be evaluated under the proposed definition of a lease. Currently, a contract for a portion of a pipeline or storage facility is not necessarily precluded from being a lease. Under the proposed leases standard, however, a capacity portion of a larger asset would have to be physically distinct or substantially all of the larger asset’s capacity to be considered a specified asset. Given that pipeline and storage contracts vary significantly in structure (e.g., in terms of contracting for the rights to a percentage of an asset’s capacity or other economic benefits), P&U entities would need to evaluate their contracts to determine whether they should account for the contracts under the guidance on leases, revenue recognition (if in a supplier situation), derivatives, or other U.S. GAAP.

Thinking It Through

P&U entities currently may structure agreements for electricity off-take, or to satisfy commodity transportation and storage needs, in order to avoid on-balance-sheet accounting under either derivative or capital lease guidance. The structures used may not offer the same accounting benefits once the proposed lease model is in effect.

Lessee Accounting Model

Initial Measurement

Under the proposed lessee accounting model, the initial measurement of a lease would be based on a right-of-use (ROU) asset approach. Under this approach, a lessee would recognize an asset for its right to use the underlying asset over the lease term and a liability for the corresponding lease obligation, measured at the present value of the future lease payments (excluding variable payments). The initial measurement of the ROU asset would include (1) initial direct costs² (e.g., legal fees, consultant fees, commissions paid) that are directly attributable to negotiating and arranging the lease, (2) lease payments to the lessor before or at the commencement of the lease, and (3) lease incentives (i.e., receipts from the lessor would reduce the ROU asset).



In addition to those payments that are directly specified in a lease agreement and fixed over the lease term, fixed 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 that would be due, such floor or minimum amount would essentially be an in-substance fixed payment). 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.

Thinking It Through

PPAs for the output of a wind farm may include a price that is fixed per unit of energy delivered. 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. Renewable PPAs that provide for a guaranteed minimum production level will require special consideration.

² The proposed model defines initial direct costs as those incremental costs “that an entity would not have incurred if the lease had not been obtained (executed).”

Subsequent Measurement

Although the FASB and IASB agreed on the lessee's initial measurement of a lease, they differed on the lessee's subsequent measurement of a lease as follows:

- *Dual-model approach (FASB)* — Lessees would classify a lease as either a finance lease or an operating lease by using classification criteria similar to those in IAS 17. This distinction would drive timing of expense in the income statement, as discussed below.
- *Single-model approach (IASB)* — Lease classification would be eliminated for lessees, and all leases would be accounted for in a manner consistent with the accounting for finance leases under the FASB's approach.

Thinking It Through

The FASB supports the dual-model approach because it believes that all leases are not equal; in the FASB's view, some leases are more akin to an alternate form of financing for the purchase of an asset while other leases are truly the renting of the underlying property. In contrast, the IASB believes that the single-model approach (i.e., one that eliminates lease classification) has greater conceptual merit and would reduce complexity.

Under the FASB's dual-model approach, a lessee would classify the lease on the basis of whether the lease transfers substantially all of the risks and rewards incidental to ownership of the underlying asset to the lessee. Therefore, a lease would be classified as a finance lease if any of the following criteria 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."
- It is reasonably certain that a lessee will "exercise an option to purchase the underlying asset."
- "The lease term is for a major part of the remaining economic life of the underlying asset."⁴
- "The sum of the present value of the lease payments [including residual value guarantees] amounts to substantially all of the fair value of the leased 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 would determine the lease classification at lease commencement and would not be required to reassess its classification unless the lease is subsequently modified and accounted for as a new lease.

Thinking It Through

These criteria are similar to those that exist today in IAS 17, and they are similar but not identical to the requirements under current U.S. GAAP. As a result, a lease that would have been classified as an operating lease may be classified as a finance lease under the new classification criteria (and vice versa). In addition, under the new guidance, a lessee would assess land and other elements separately unless the accounting impact for the land would be insignificant. Although this approach is consistent with that of IFRSs, it differs from the lease accounting guidance under current U.S. GAAP, which provides that if a lease does not transfer ownership of the real estate or contain a bargain purchase option, a lessee would evaluate the lease classification for the land and other elements as a single unit unless the fair value of the land is 25 percent or more of the total fair value of the leased property at lease inception. The proposed change from current U.S. GAAP may result in more bifurcation of real estate leases into separate elements and may affect the allocation of the lease payments to the various elements.

³ Quoted text is from [FASB Agenda Paper 268](#).

⁴ As noted on the [project update page](#) of the FASB's Web site, the Board decided to provide an exception to this lease classification test for leases that commence "at or near the end" of the underlying asset's economic life. Further, the Board decided that "the final leases standard should include implementation guidance that one reasonable approach to determining the applicability of this exception would be to conclude 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."

Under either a finance lease or an operating lease, the lessee would amortize the lease liability by using the applicable discount rate. Accordingly, the lease liability would be measured at the present value of the remaining lease payments, which the lessee would calculate by discounting the payments at the rate established at lease commencement.

The ROU asset of a finance lease would be amortized in the same manner as other nonfinancial assets; that is, it would generally be depreciated on a straight-line basis unless another systematic method would be appropriate. Since interest expense is higher in the early years of a financing liability, the combination of interest expense and ROU amortization will result in a front-loaded expense profile for finance leases. Entities would separately present the interest and amortization expenses in the income statement.

The ROU asset of an operating lease would be calculated 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. This results in a periodic lease expense for operating leases equal to the lease payments made over the lease term, recognized on a straight-line basis unless another systematic method is more appropriate.

Regardless of classification, the ROU asset would be subject to impairment testing in a manner similar to how other long-lived assets are tested for impairment. If the ROU asset for a lease classified as an operating lease is impaired, the lessee would amortize the remaining ROU asset evenly over the remaining lease term. Therefore, in periods after the impairment, the recognized lease expense would comprise the ROU amortization and lease liability accretion for the period (i.e., the periodic lease expense would no longer be recorded on a straight-line lease basis).

Lessor Accounting

In contrast to its approach to developing a new lessee model, the FASB decided to make only minor modifications to the current lessor model. Under the new standard, a lessor would classify the lease as a sales-type lease, direct financing lease, or operating lease by using the classification criteria previously discussed for lessees:

- *Sales-type lease* — A lease in which the lessee effectively gains control of the underlying asset during the lease term. The lessor would derecognize the underlying asset and recognize a lease receivable and unguaranteed residual asset. Any resulting selling profit or loss would be recognized at lease commencement. Initial direct costs would be recognized as an expense at lease commencement unless there is no selling profit or loss. In this case, the initial direct costs would be deferred and recognized over the lease term. In addition, the lessor would recognize interest income from the lease over the lease term.
- *Direct financing lease* — A lease in which the lessee does not effectively obtain control of the asset but (1) the present value of the lease payments and any residual value guarantee (which could be provided entirely by a third party or could comprise a lessee guarantee coupled with a third-party guarantee)⁵ 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. The lessor would derecognize the underlying asset and recognize a lease receivable and unguaranteed residual asset. The lessor's profit, initial direct costs, and interest income would be deferred and amortized into income over the lease term.
- *Operating lease* — A lease in which the lessee does not effectively obtain control of the asset over the lease term because none of the classification criteria are met. Income resulting from an operating lease would be recognized on a straight-line basis unless another systematic basis would be 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 obtained) are to be deferred and expensed over the lease term in a manner consistent with the way lease income is recognized.

⁵ 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 would classify the lease as a sales-type lease.

Thinking It Through

While the FASB aligned lessor accounting with the new revenue guidance in ASC 606 in many respects, there is an important distinction that may affect energy 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. In contrast, under the new leases standard, variable lease payments would generally be excluded from the determination of a lessor's lease receivable. It is unclear whether the new standard will include guidance on accounting for arrangements that have a significant "variable-only" payment stream. There is a possibility that direct financing leases or sales-type leases may result in inception losses for the lessor if the lease receivable plus the unguaranteed residual asset is less than the net carrying value of the asset being leased. In the renewable space, this outcome may occur given the long-dated nature of certain off-take arrangements, coupled with the absence of fixed rents in many renewable PPAs (i.e., payments are contingent on production). P&U entities should evaluate the final ASU once issued to see how the final provisions may affect these types of arrangements.

Effective Date and Transition

The new guidance would be effective for public business entities for annual periods beginning after December 15, 2018 (i.e., calendar periods beginning on January 1, 2019), and interim periods therein. For all other entities, the standard would be effective for annual periods beginning after December 15, 2019 (i.e., calendar periods beginning on January 1, 2020), and interim periods thereafter. Early adoption would be permitted for all entities. Entities would be 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 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 required effective date). It is our understanding that those early adopters would be expected to apply the relevant guidance in the new revenue guidance to the extent that it affects their lease accounting. All other aspects of the new revenue standard would wait until full adoption of that standard.

Next Steps

The FASB is expected to issue its final ASU introducing the new leases model (to be codified as ASC 842) in February 2016. The IASB issued its final leases standard, IFRS 16, on January 13, 2016. For more information about IFRS 16, see Deloitte Touche Tohmatsu Limited's January 13, 2016, *IFRS in Focus*. Keep an eye out for our *Heads Up* publication on leases that will be issued shortly after the issuance of the FASB's final standard.



Section 8 FERC Enforcement Activities

In November 2015, the FERC Office of Enforcement (OE) issued the [2015 edition](#) of its report on enforcement (the “2015 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 2015 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.

Highlights

2015–2016 Enforcement Trends

The 2015 Report demonstrates the continued focus on industry behavior in the markets. As in the past couple of years, the majority of the investigations, Notices of Alleged Violation (NAVs), and Orders to Show Cause (OSCs) in fiscal year 2015 involved alleged violations of rules related to market behavior. However, while the OE’s focus on markets is not new, the 2015 Report identifies a few new trends:

- *Increased focus on RTOs, ISOs, and market monitors* — There has been greater focus on both industry compliance with the RTO/ISO rules and the use of RTOs/ISOs and market monitors in the monitoring of market activities and identification of potential violations. For example, FERC issued a [Notice of Proposed Rulemaking](#) (NOPR) on the collection of additional data from RTOs and ISOs to support the activity of the OE’s Division of Analytics and Surveillance (DAS). For more information about the NOPR, see [Analytics and Surveillance](#) below.
- *Interagency data sharing* — While the work to define jurisdictional lines between FERC and CFTC continues, fiscal year 2015 has seen more cooperation in data sharing between the agencies.
- *Heightened focus on reliability* — The increased focus on reliability issues is reflected in (1) the settlement activity described in the 2015 Report and (2) FERC’s recent discussions of its intent to expand its audit focus to include cyber-related reliability regulations in 2016.

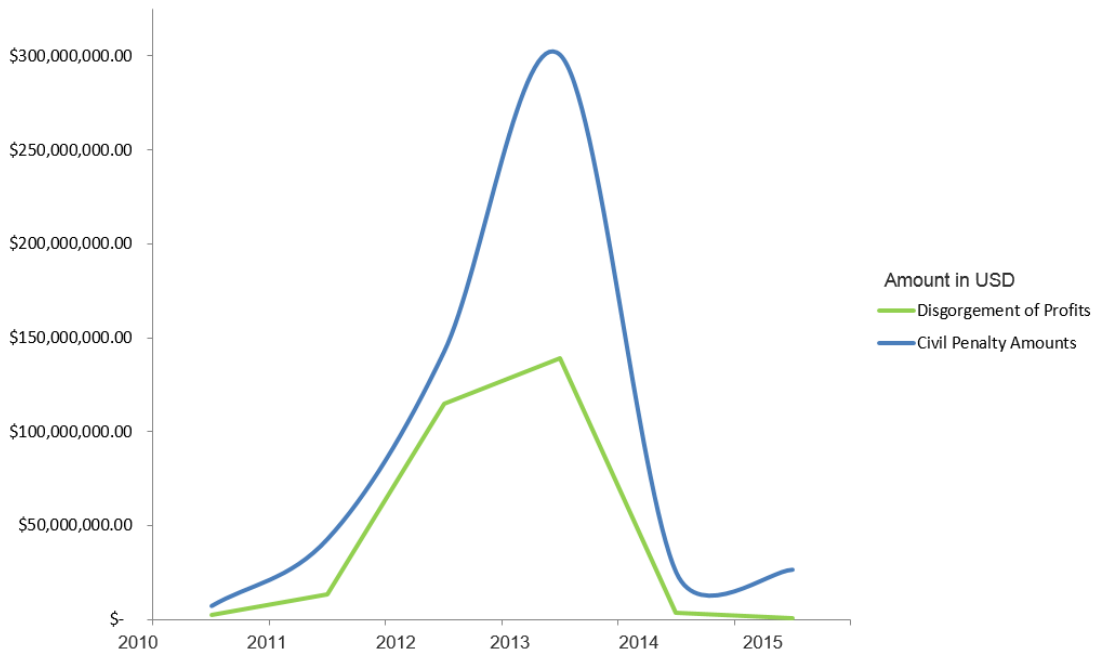
2015 by the Numbers

In fiscal year 2015, the OE’s Division of Investigations (DOI) “opened 19 new investigations while bringing 22 pending investigations to closure either with no action or through a Commission-approved settlement.” Further, the DOI staff negotiated settlements in fiscal year 2015 that allowed for the recovery of “a total of almost \$26.25 million in civil penalties and disgorgement of nearly \$1 million in unjust profits.” The OE’s Division of Audits and Accounting (DAA) conducted 22 audits in fiscal year 2015, up from 19 in fiscal year 2014. The DAA issued 360 corrective action recommendations and directed refunds and recoveries totaling \$26.3 million, more than double the fiscal year 2014 total of \$11.7 million. Further, the DAS worked on more than 30 investigations and continued its reviews of potential misconduct, which again in fiscal year 2015 resulted in referrals to the DOI.

Included in this activity was a series of settlements with P&U companies in a significant reliability investigation resulting from a 2011 blackout in the southwestern United States. In the four settlements, the companies agreed to (1) pay \$22.65 million in civil penalties, (2) implement a significant number of mitigating measures, and (3) invest in reliability enhancements above and beyond the NERC Reliability Standards requirements.

In contrast to fiscal year 2014, in which civil penalties and disgorgements declined significantly from the prior two years, the monetary amount of overall imposed civil penalties and disgorgements increased in fiscal year 2015 to \$26.25 million in penalties and \$978,186 in disgorgements. The chart below provides a high-level view of the penalty trends over the past few years. In addition, more than half a billion dollars in imposed penalties and disgorgements is currently the subject of appeals across several federal jurisdictions (see [Investigations](#) below for more information).

FERC Financial Impact 2010-2015



Source: www.FERC.gov

Activities by Enforcement Division

The OE has four divisions: Investigations, Audits and Accounting, Energy Market Oversight, and Analytics and Surveillance. Highlights of each division's recent activities are summarized below.

Investigations

The majority of investigations are resolved through either settlement or dismissal. For fiscal year 2015, FERC approved nine settlements, resolving investigations in six matters for a total of \$26.25 million in civil penalties plus almost \$1 million in disgorgements. In half of those matters, FERC granted a credit under the Penalty Guidelines, which helps reduce the penalty. The violations settled were related to market manipulation, tariffs, and reliability. This composition of violations differs slightly from that in fiscal year 2014 and is a departure from the broader range of issues encountered by FERC in prior years, reinforcing FERC's increased focus on market manipulation and reliability.

The biggest news from the DOI for 2015 involves its litigation of investigation actions in federal court. In fiscal year 2015, the DOI issued three Orders to Show Cause and filed associated actions to enforce civil penalty assessments. FERC is now litigating six actions in federal court (including actions filed before fiscal year 2015) to enforce penalty and disgorgement assessments totaling more than half a billion dollars (\$544,600,000 in penalties and \$42,242,999 in unjust profits). The industry is watching since the results may affect how FERC enforces market manipulation cases in the future.

With a number of the market manipulation cases in active litigation, the majority of the \$26.25 million settlement total is represented by the reliability cases coming out of the 2011 blackout. In fiscal year 2015, FERC and NERC jointly entered into the following four settlements related to the blackout:

- *CAISO* — \$6 million penalty and agreed-upon mitigation and compliance monitoring.
- *Southern California Edison Co.* — \$650,000 penalty and agreed-upon mitigation and compliance monitoring.
- *Western Electricity Coordinating Council (WECC)* — \$16 million penalty and agreed-upon mitigation and compliance monitoring.
- *Western Area Power Authority-Desert Southwest* — \$0 penalty and agreed-upon mitigation and compliance monitoring.

These settlements, together with two related settlements reached in fiscal year 2014, close the investigation of the 2011 blackout.

In addition to the reliability settlements, FERC approved a settlement related to a market manipulation investigation involving Twin Cities Energy LLC, two affiliates, and three individuals in the amount of \$2.5 million in civil penalties and \$978,186 in disgorgement. The investigation alleged that Twin Cities and the individual traders involved “had violated the Commission’s Anti-Manipulation Rule by flowing physical power in such a way as to move the real-time physical market of the MISO to the benefit of related financial positions.”

The Commission also reached a settlement with Columbia Gas Transmission LLC related to an investigation into tariff violations following a referral from the DAA. On the basis of that investigation, the DOI staff “determined that Columbia Gas had violated the General Terms and Conditions of its FERC Gas Tariff by failing to post notices of the auctions of its available firm capacity” on a public bulletin board. The civil penalty in that case was \$350,000 and some additional imposed mitigation and reporting obligations.

Self-reports and the investigations they engender remain a big part of the DOI activity in a given year. The majority of the 78 reports closed by the DOI staff in fiscal year 2015 were related to RTO/ISO violations (33 self-reports) and regulatory filing violations (21 self-reports); these figures represent fairly large increases over the 13 self-reports of RTO/ISO violations and 8 self-reports of regulatory filing violations that were closed in fiscal year 2014. With FERC’s increased focus on the use of RTO/ISO rules and market monitors, this trend may continue into fiscal year 2016.

Audits and Accounting

In fiscal year 2015, the OE’s DAA:

- Completed 22 audits of public utilities, oil pipeline companies, natural gas pipelines, and storage companies (financial and nonfinancial). These audits resulted in 360 recommendations for corrective action and directed refunds and recoveries of \$26.3 million.
- Confirmed that 96 percent of the DAA’s audit recommendations were implemented within six months.
- Reviewed 376 Commission filings. These are among the 1,395 Commission filings that the DAA reviewed over the past five years “to ensure proper accounting is followed and to advise the Commission on potential rate effects.”

Audit Findings

Below are some of the areas in which the DAA has identified consistent patterns of noncompliance over the past several years (quotes are from the 2015 Report):

“Formula Rate Matters. DAA continues to ensure compliance with the Commission’s accounting and the FERC Form No. 1 requirements for costs that are included in formula rate recovery mechanisms used to determine billings to wholesale customers. Formula rate audits in recent years have observed certain patterns of noncompliance in the following areas:

- **Internal Merger Costs** — Utilities have included merger-related costs in rates without Commission approval. Such unapproved costs typically relate 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, and they must have appropriate controls and procedures to ensure that merger-related costs are tracked and excluded from formula rates.
- **Tax Prepayments** — Utilities have incorrectly recorded income tax overpayments for which they will elect to receive a refund (in lieu of a credit being applied 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 overpayments are properly recorded in Account 146, Accounts Receivable, from Associated Companies, or Account 143, Other Accounts Receivable, as appropriate.
- **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.
- **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.
- **Merger Goodwill** — Utilities have included goodwill in the equity component of the capital structure, absent Commission approval. It is the Commission’s long-standing policy that goodwill should be excluded from rates.
- **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 without the appropriate policies and controls being utilized to ensure that those project costs are classified as distribution plant and the related depreciation is appropriately classified.
- **Unused Inventory and Equipment** — Utilities have included the cost of materials, supplies, and equipment purchased for construction projects without removing the cost of items unused in whole or in part from the cost of a project.
- **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 their formula rates.”

Example Finding

The findings involved improper accounting and rate treatment for income tax overpayments, improper recovery of merger-related internal labor costs, accounting misclassifications in administrative and general expense accounts, improper AFUDC accruals, improper inclusion of asset retirement obligation amounts in formula rates, failure to use Commission-approved depreciation rates for transmission and general utility plant included in formula rates, improper accounting for the underfunded status of [the company’s] pension fund, and improper record retention practices.

“Natural Gas Accounting and Tariff Matters. DAA continues to evaluate natural gas pipelines’ compliance with the Commission’s accounting, the FERC Form No. 2, and tariff requirements to ensure transparency and accuracy of data reported to the Commission. In recent comprehensive natural gas audits, DAA has observed patterns of noncompliance in the following areas:

- **Tariff Issues** — Natural gas pipelines have failed to comply with the FERC gas tariff valuation method for system gas activities, Operational Balancing Agreement stipulations to manage and monitor imbalance activity, and North American Energy Standards Board requirements related to reporting Operational Available Capacity data.
- **Pipeline Integrity Management Costs** — DAA has discovered that some natural gas pipelines have misclassified integrity management costs that should have been recorded as maintenance expenses. The Commission’s 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.
- **Erroneous Accounting and Reporting** — Natural gas pipelines have failed to comply with the Commission’s accounting requirements for 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, gains from the sale of cushion gas, and penalties assessed by the U.S. Department of Transportation. DAA discovered misclassification issues among the categories of costs representing operational transmission expenses, other gas supply expenses, and underground storage expenses.”

Example Finding

[The company] improperly had recorded more than \$75 million in pipeline integrity management program costs as operating expenses instead of maintenance expenses from 2012–2014.

“Consolidation. Commission accounting regulations require the equity method of accounting for all investments in subsidiaries. Recent audit activity has found jurisdictional companies incorrectly using the consolidation method for accounting for subsidiaries instead of the equity method as required by the Commission. 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.”

Example Finding

[The company] improperly accounted for its investment in a subsidiary under the consolidation method of accounting instead of using the equity method of accounting.

“Nuclear Decommissioning Trust Funds. The Commission’s regulations concerning nuclear decommissioning trust funds require 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, and accurately report the amount of Commission-jurisdictional money in the trusts.”

Example Finding

[The company did not clearly separate] wholesale from retail monies in its trust fund and [failed] to file annual financial reports for its trust fund activities with the Commission.

“Price Index Reporting and FERC Form No. 552 Reporting. DAA’s recent energy-reporting audits have revealed common deficiencies that have led to transactions that are not reported 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 nonreportable transactions. These reporting errors on the FERC Form No. 552 hinder the usefulness and transparency of the form's contents."

Example Finding

[The company failed] to report all reportable transactions to price index publishers and [failed] to disclose all affiliate companies on its FERC Form No. 552 filings.

"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."

Example Finding

The audit found that [the company] had overstated interest expense recorded in Account 427, Interest on Long-term Debt, and had inappropriately subtracted the balance of Account 181, Unamortized Debt Expense, from the long-term debt balance in computing AFUDC rates. [The company] also had included ineligible costs, such as contract retention, unpaid use tax accruals, and expenditures from a canceled project in its construction cost component and had over-accrued AFUDC.

"Capacity Transparency and Allocation. Interstate natural gas pipelines are required to post available pipeline capacity on their websites. These postings promote transparency of available pipeline capacity and enable greater competitive and efficient use of such capacity; however, recent audits have identified common deficiencies in reported available pipeline capacity where quantities were either omitted or incorrectly reported. The result is that some shippers may not have been able to avail themselves of available pipeline capacity."

"Open Access Transmission Tariffs (OATT). An essential goal of open access is to support efficient and competitive markets, and DAA recently has noted instances in which company actions did not support this goal. Specifically, the companies billed customers using incorrect rates, posted inaccurate available transfer capacity data, failed to release transmission capacity in accordance with Commission-approved tariffs, and failed to follow scheduling protocols to ensure appropriate transmission reservations over constrained interfaces."

"Untimely Filing of Commission Reports. DAA identified instances where companies have failed to timely file various reports with the Commission. These instances included reports such as decommissioning trust fund reports and required filings and reports related to mergers. Failure to timely file these reports limits the Commission and industry's ability to use this data. It also undermines the transparency of information and creates doubt regarding the effectiveness of these companies' compliance programs."

"Record Retention. DAA has identified instances where records are not retained in accordance with Commission regulations. In some cases, DAA determined that records associated with assets acquired through acquisitions had not been obtained from the original owner. 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."

"Capacity Markets. DAA audits have pointed out that jurisdictional companies need to strengthen controls over the reporting of capacity additions to bid into and otherwise participate in capacity markets."

Market Oversight

The Division of Energy Market Oversight (“Market Oversight”) is charged with monitoring the wholesale natural gas and electric power markets in the United States. The 2015 Report states that “[t]o carry out this responsibility, Market Oversight continuously examines the structure and operation of the markets to identify anomalies, flawed market rules, tariff and rule violations, and other unusual market behavior as well as significant market events and trends.” In addition, Market Oversight “collaborates with other Commission offices to develop regulatory strategies, focusing on the competitiveness, fairness, and efficiency of wholesale energy markets.”

In March 2015, Market Oversight issued its annual “[State of the Markets](#)” report, in which it provided an assessment of significant events in the energy markets for 2014. The key observations from the report focused on natural gas, the extreme weather in the early winter months of 2014, and the resulting impact to natural gas infrastructure and the electric power markets. There was also discussion of the relative stability of prices overall throughout 2014, continued increases in natural gas production, and the plunge in oil prices. Further, there was some focus on the significant changes occurring within the organized wholesale electricity markets.



In addition to the annual report, Market Oversight issues seasonal assessments and holds “snapshot calls” and domestic and foreign delegation briefings. These are all designed to provide the P&U industry with interactive information related to the markets.

Further, Market Oversight issued an updated version of its [Energy Primer](#) in 2015. As noted in the OE’s 2015 Report, this resource manual on energy market basics provides “a broad overview of the physical wholesale markets for natural gas and electricity and energy-related financial markets.”

The 2015 Report also highlights the continued support provided by Market Oversight to the other FERC enforcement divisions as well as Market Oversight’s focus on monitoring the FERC forms and filings. In particular, the 2015 Report notes that Market Oversight reviews Electric Quarterly Reports filed with the Commission and plays a key role in FERC’s “eForms Refresh Project” on transitioning to a new electronic submission format.

Analytics and Surveillance

In an effort to restore and enhance the analytic capability of the OE, FERC created the DAS in February 2012. The 2015 Report notes that the DAS’s topics of focus are “(1) natural gas surveillance, (2) electric surveillance, and (3) analytics for reviewing market participant behavior.”

One of the DAS’s more notable activities in fiscal year 2015 was its involvement in the development of FERC’s NOPR on the collection of connected entity data, which was issued on September 17, 2015. The NOPR (commonly referred to as the “Connected Entities Data NOPR”) is seeking to require most energy market participants to report (through a requirement imposed on RTOs and ISOs) detailed information about the market participants’ “connected entities,” a term that is defined very broadly to include entities that have ownership, debt, contractual, and even some employment relationships with the participants. FERC stated that the NOPR’s objective is to provide greater transparency into the marketplace to better detect and deter market manipulation. The initial industry response was one of concern, enough to request both an extension for the filing of comments (which were originally due by November 30, 2015) and a FERC technical conference to discuss the implications and burdens of the proposal. Comments are now due by January 22, 2016.

Throughout fiscal year 2015, the DAS continued to (1) enhance its surveillance capabilities, processes, and tools; (2) expand its view across markets and the RTOs/ISOs; and (3) support the other FERC enforcement divisions.

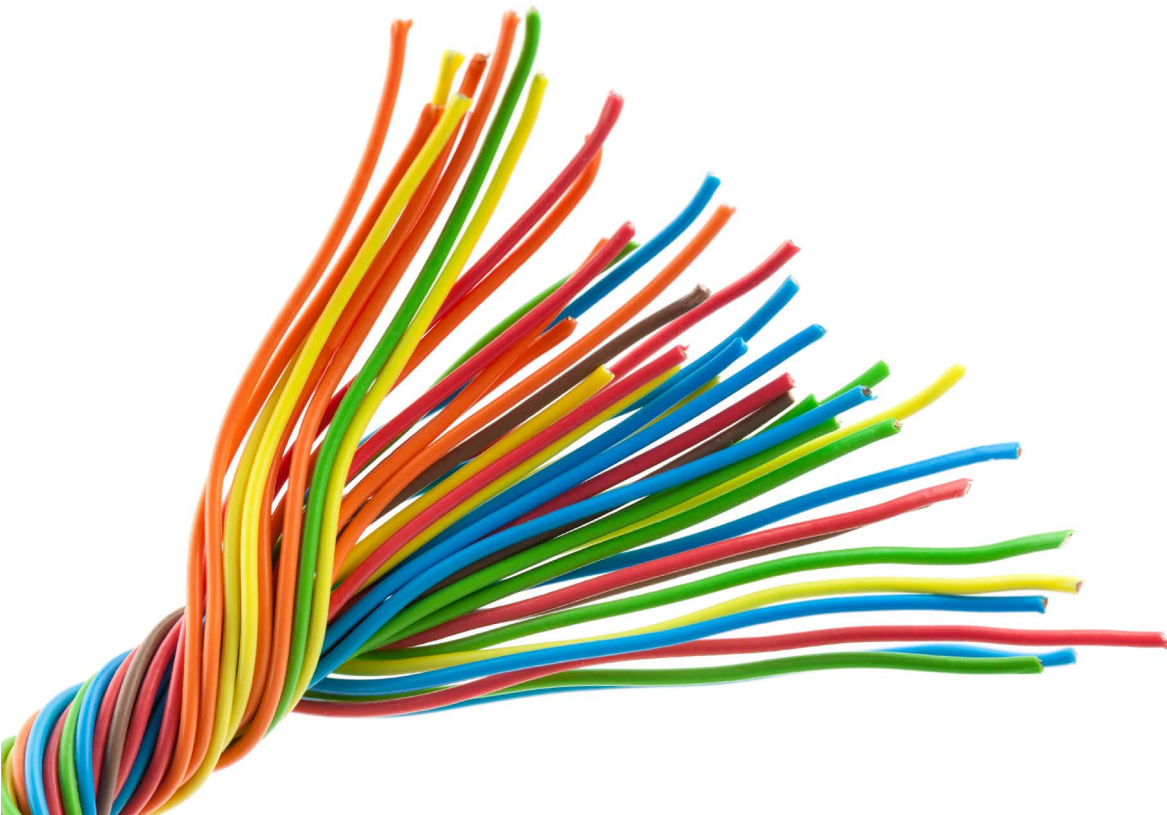
Other Developments

Department of Energy Audit of FERC Enforcement

In September 2015, the DOE issued a [report](#) on its audit of FERC enforcement processes. The audit looked at 7 closed investigations, 20 closed hotline cases, and 10 closed self-report cases. The review also assessed concerns raised and submitted by U.S. senators, including allegations of improper “quid pro quo” activity associated with an approved merger. Ultimately, the DOE inspector general found “nothing . . . to indicate that OE was not performing enforcement activities in accordance with relevant policies and procedures.” The DOE therefore closed the audit without making recommendations.

FERC Composition

In April 2015, FERC Commissioner Norman Bay assumed the role of FERC chairman; previously, he had served as director of the OE from 2009 until his appointment as a FERC commissioner in 2014. Commissioner Cheryl LaFleur served as acting chairman from 2014 until April 2015, when she resumed her role as a commissioner. Collette Honorable was confirmed as a commissioner in December 2014. Commissioner Phil Moeller announced his departure from FERC and subsequently left his position in October 2015 after serving on the Commission since July 2006, leaving a vacancy that remains as of the issuance date of this publication.



Section 9 Income Tax Update

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 10](#).

Normalization — Deferred Tax Assets for Net Operating Loss and Minimum Tax Credit Carryforwards

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

- Whether the DTA for the portion of an NOL 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 private letter rulings addressing the application of the deferred tax normalization requirements when an NOL carryforward exists. Those rulings are summarized as follows:

- The taxpayer in [PLR 201418024](#) incurred taxable losses in excess of taxable income over a multiyear period and as of its test year had an NOL carryforward and an MTC carryforward (because utilization of alternative minimum tax NOL carryforwards is limited to 90 percent of alternative minimum taxable income). The amount of accelerated depreciation claimed in the two loss years exceeded the amount of NOLs incurred in those years. The utility filed a general rate case with plant-based DTL balances reduced by the amounts of tax not deferred as a result of the NOL and MTC carryforwards. The commission issued an order in which the rates were based on DTL balances unreduced by the effects of the carryforwards.

In its analysis, the IRS stated that “[t]here is little guidance on exactly how an [NOL or MTC carryforward] must be taken into account in calculating” DTLs in accordance with the normalization requirements but that “it is clear that both must be taken into account” for ratemaking purposes. The ruling indicates that the commission “has stated that in setting rates it includes a provision for deferred taxes based on the entire difference between accelerated tax and regulatory depreciation, including situations in which a utility has” an NOL or MTC carryforward. This approach “allows a utility to collect amounts from ratepayers equal to income taxes that would have been due” in the absence of the NOL and MTC carryforwards. Although the IRS accepted these commission assertions as true for purposes of the ruling, it did not conclude that the commission had actually set rates in accordance with the assertions and indicated that the assertions “are subject to verification on audit.” Further, the IRS held that because the commission had already taken the NOL and MTC carryforwards into account in setting rates, the reduction of rate base by the full amount of the DTL account without regard to the balances of the carryforward accounts was consistent with the normalization requirements.

- The taxpayer and its consolidated group in [PLR 201436037](#) and [PLR 201436038](#) incurred or expected to incur NOLs resulting in NOL carryforwards. The taxpayer computed the depreciation-related portion of its DTA by using a with-or-without method in which the NOL carryforward was considered “attributable to accelerated depreciation to the extent of the lesser of” the amount of accelerated depreciation or the NOL carryforward. Other rate-case participants proposed different approaches. For example, in [PLR 201436037](#), a participant proposed an approach in which regulatory tax expense would be reduced by the amount of the DTA determined to be attributable to accelerated depreciation.

In both rulings, the IRS stated that regulations clearly indicate that an entity must take into account the effects of an NOL carryforward attributable to accelerated depreciation in determining the rate base reduction for DTLs for normalization purposes but that the regulations provide “no specific mandate on methods.” The IRS further

stated that the with-or-without method ensures that “the portion of the [NOL carryforward] attributable to accelerated depreciation is correctly taken into account by maximizing the amount of the [carryforward] attributable to accelerated depreciation.” Further, the method “prevents the possibility of ‘flow through’ of the benefits of accelerated depreciation to ratepayers.” The IRS ruled that reducing rate base by the full amount of the DTL account balances offset by a portion of the DTA for the NOL carryforward “that is less than the amount attributable to accelerated depreciation” calculated on a with-or-without basis would be inconsistent with the normalization requirements. Moreover, in [PLR 201436037](#), the IRS noted that any reduction to tax expense included in cost of service to reflect the tax benefit of an NOL carryforward would be inconsistent with the normalization requirements because such a reduction “would, in effect, flow through the tax benefits of accelerated depreciation deductions through to ratepayers even though the [t]axpayer has not yet realized such benefits.”

- The utility subsidiaries in [PLR 201438003](#) and [PLR 201519021](#) forecasted that they would incur NOLs resulting in NOL carryforwards in their test periods. In each rate proceeding, the DTL used to reduce rate base was reduced by the amount of the DTA for the NOL carryforward. The utilities’ commission issued orders in which the commission held 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 utilities to seek rate adjustments if the utilities obtain private letter rulings affirming the utilities’ 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 its private letter rulings, the IRS stated that regulations clearly indicate that an entity must take into account the effects of an NOL carryforward attributable to accelerated depreciation in determining the rate base reduction for DTLs for normalization purposes but that the regulations provide “no specific mandate on methods.” The IRS further stated that the with-or-without method ensures that “the portion of the [NOL carryforward] attributable to accelerated depreciation is correctly taken into account by maximizing the amount of the [carryforward] attributable to accelerated depreciation.” Further, the method “prevents the possibility of ‘flow through’ of the benefits of accelerated depreciation to ratepayers.” In both rulings, 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.

- 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 its private letter ruling, the IRS stated that regulations clearly indicate that an entity must take into account the effects of an NOL carryforward attributable to accelerated depreciation in determining the rate base reduction for DTLs for normalization purposes but that the regulations provide “no specific mandate on methods.” The IRS 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.

- 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 its private letter ruling, the IRS stated that regulations clearly indicate that an entity must take into account the effects of an NOL carryforward attributable to accelerated depreciation in determining the rate base reduction for DTLs for normalization purposes but that the regulations provide “no specific mandate on methods.” The

IRS further stated that the “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 through to rate payers 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.

Normalization — 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 private letter rulings 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 private letter rulings — [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 the 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 by using 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 of time.

The IRS also held in the five private letter rulings that the computations of accumulated deferred income taxes for 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 computations 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. However, the IRS also indicated in PLR 201541010 that when the true-up is calculated, (1) the proration formula applies to the original projection but (2) the actual amount added to the accumulated deferred income taxes 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.

Normalization — 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](#) 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 an 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 agency is a United States governmental agency and 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.

Accounting for Investments in Qualified Affordable Housing Projects

In January 2014, the FASB issued [ASU 2014-01](#) (in response to the EITF consensus on Issue 13-B), which modifies ASC 323-740’s measurement and presentation alternative for certain investments in affordable housing projects that qualify for the low-income housing tax credit (LIHTC) 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 LIHTC investments if the following conditions are met:

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

In addition, other transactions between the investor and the limited liability entity would not preclude an investor from using the proportional amortization method to account for LIHTC investments 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 an LIHTC investment accounted for under the alternative method for impairment when it is more likely than not that the investment will not be realized, and measure an impairment loss as the amount by which the investment’s carrying amount exceeds its fair value.
- Disclose 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 LIHTC investments 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.”

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. The elimination of the current classification of certain DTAs and DTLs is consistent with the balance sheet presentation of deferred taxes under IFRSs and for FERC reporting purposes under AI93-5-000, *Accounting for Income Taxes*. Therefore, upon adoption of the ASU, a common reporting difference between FERC and U.S. GAAP will be eliminated. 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*.



Section 10 Renewable Energy

Production Tax Credits, Investment Tax Credits, and Treasury Grants

Introduction

Entities calculate PTCs by using stated rates (e.g., 2015 wind production at 2.3 cents) multiplied by kWh generated during each of the first 10 years of operation. 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 and ITC eligibility. Under tax law enacted as of the end of 2015, for most types of facilities eligible for PTC, construction of the plant must begin before January 1, 2017, for the plant to be eligible for PTC. 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, 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 tax law enacted as of the end of 2015, for most types of facilities eligible for ITC, construction of the plant must begin before January 1, 2017, for the plant to be eligible for ITC. 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 PTC or ITC 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 sequester, 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, 2015, and on or before September 30, 2016, will be reduced by 6.8 percent, irrespective of when the application was received by the Treasury. The sequestration rates for the fiscal years ending September 30, 2015, and September 30, 2014, were 7.3 percent and 7.4 percent, respectively.

PTC and ITC in Lieu of PTC

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

Further, in August 2014, the IRS issued [Notice 2014-46](#), which clarifies the application of the physical work test, the effect of certain transfers, and the application of the safe harbor for facilities that have "incurred less than five percent, but at least three percent, of the total cost of the facility before January 1, 2014." Regarding the physical work test, Notice 2014-46 indicates that the Notice 2013-29's list of activities that constitute physical work is not all-inclusive and that any one of the activities in 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 Notice 2013-29 was to demonstrate the "single project" concept, not to provide a "work or monetary or percentage threshold" that would meet the physical work criterion.

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

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

2014, by the unrelated transferor developer may be taken into account for purposes of determining whether the facility satisfies the Physical Work Test or Safe Harbor.

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

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

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

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 2015-32](#), issued in May 2015, published “the inflation adjustment factor and reference prices for calendar year 2015 for the renewable electricity production credit and the refined coal production credit under section 45 of the Internal Revenue Code.” The notice specified that the inflation adjustment factor for qualified energy resources and refined coal was 1.5336 and that the reference price for facilities producing electricity from wind was 4.50 cents per kWh. Further, the notice stated that the PTC rate for 2015 generation was 2.3 cents per kWh for wind, closed-loop biomass, and geothermal energy facilities and 1.2 cents per kWh for open-loop biomass, landfill gas, trash, hydropower, and marine and hydrokinetic renewable 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, ITC 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 it would account for the cash grants by analogy to ASC 450 and, more specifically, to its guidance on gain contingencies. In this specific case, the power plant that qualified for the Section 1603 grant was part of the company's rate-regulated operations. Because the regulator would require that the benefits from the Section 1603 grant reduce customer rates, the Section 1603 grant qualifies under the gain contingency recognition rules of ASC 450 and the benefit would be recorded as a regulatory liability rather than as an income statement gain.

Accounting for PTCs

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

Structuring Project Arrangements and the Resulting Accounting and Tax Implications

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

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

Motivation for Structures

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

The early years of a renewable energy project that is owned and operated directly or indirectly by a renewable energy entity often do not generate enough taxable income for an entity to take advantage of the tax benefits 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 a few years ago, these investors have evolved from the typical investment banks and insurance companies to foreign investors — who have become more active in renewable energy structures in the United States by using these investments to enter the U.S. market — and other commercial entities that are interested in investing in renewable energy. Such investors have available cash for investing opportunities and 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 [IRS Revenue Procedure \("Rev. Proc."\) 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 apply 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.



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

The accounting and reporting considerations discussed above apply to renewable energy entities. An investor would need to determine whether a structure constitutes equity or a debt security. If the investor concludes that a structure constitutes equity with no readily determinable fair value, it would need to determine whether it exercises significant influence over the investee in accordance with ASC 323-10, in which case it would apply equity method accounting. If, however, an investor concludes that a structure constitutes a debt security, it would classify and account for the structure in accordance with ASC 320-10.

Both renewable energy entities and investors need to evaluate structures under ASC 810 to determine whether the partnership or the renewable energy project is a variable interest entity and, ultimately, which party is required to consolidate the partnership that is contained in such structures.

Variations on Traditional Structures

The terms and form of structures have continued to evolve as a result of such factors as current market conditions, the availability and types of investors, fast-approaching deadlines to qualify for renewable energy tax benefits, and pending legislation 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 might wish to consider the guidance in ASC 480. In addition, renewable energy entities should apply ASC 815-15 to determine whether a put option (or withdrawal right) represents an embedded derivative in the partnership agreement that must be bifurcated.

Tax Considerations

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

Other Variations

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

- Preset cash distribution ratios among the renewable energy entity and investors from the inception of the arrangement or upon the occurrence of an event specified in the partnership agreement.
- Predetermined date (as opposed to the achievement of a target internal rate of return on the investment in the partnership) that triggers the change in the allocation of tax benefits and cash distributions among the renewable energy entity and investors.
- Fixed ownership percentages among the members over the life of the partnership.
- A requirement for the partnership to distribute a fixed percentage of available cash (as defined in the partnership agreement) as preferred cash distribution to the investors before available cash is distributed to members of the partnership.

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

Other Accounting Considerations

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

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

When an investor receives allocations of income/loss that are disproportionate to its equity interest in the investee (such as that found in structures), it may not be appropriate to record equity method income/loss on the basis of the percentage of equity interest owned. Under ASC 323-10 and ASC 970-323-35-17, such arrangements should be "analyzed to determine how an increase or decrease in net assets of the venture (determined in conformity with 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 HBLV 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 HBLV 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 HBLV method to allocate U.S. GAAP equity and income/loss in structures often incorporates tax concepts. Further, the underlying mechanics of the HBLV 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 HBLV calculation to properly reflect the facts and circumstances of each structure.

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

Deferred Tax Considerations

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

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

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

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

Accounting for Traditional Structures Under IFRSs

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

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

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

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

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

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

Renewable Energy

Start-Up Versus Development Costs and Timing of Capitalization

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

Various costs are incurred during each development stage. The primary accounting consideration related to these costs is whether to record them as expense or capital items and, if capital items, when capitalization of such costs should commence and cease. In making this determination, entities should look to the guidance in ASC 720-15, 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 completed, the asset is shut down and certified and control is transferred from the manufacturer to the owner/operator upon the latter's signature of acceptance. All revenues produced before the owner/operator's acceptance of the project assets are considered test revenue. Test revenue is treated as a reduction of construction work-in-process in accordance with ASC 970-10-20, which states that "[r]evenue-producing activities

engaged in during the holding or development period . . . reduce the cost of developing the property for its intended use, as distinguished from activities designed to generate a profit or a return from the use of the property."



Example

Upon the near-completion of a wind turbine project, the turbines must be commissioned before being placed into commercial operation. As part of standard tests that are performed during the commissioning process, each wind turbine will produce some amount of electricity. Once the testing is complete, the turbine is shut down, a turbine completion certificate (TCC) is issued by the manufacturer, and the manufacturer relinquishes control of the turbine and transfers it to the owner/operator upon the latter's signature of acceptance. All revenues produced by a particular wind turbine before the owner's official acceptance of the TCC are considered test revenue and accounted for as a reduction of construction work-in-process in accordance with ASC 970-10-20.

Further, entities should develop a capitalization policy in accordance with ASC 360, ASC 720, and ASC 835 and apply this policy consistently to all of their projects. A best practice for capitalization policies is to incorporate entity-specific considerations, including factors affecting management's judgment about properly accounting for start-up and development costs. At a minimum, entities should consider incorporating the following into their capitalization policy:

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



Appendixes

Appendix A — Abbreviations

Abbreviation	Description
ABS	asset-backed security
AD	assistant director
AFS	available for sale
AFUDC	allowance for funds used during construction
AICPA	American Institute of Certified Public Accountants
APIC	additional paid-in capital
ARO	asset retirement obligation
ARPA-E	Advanced Research Project Agency — Energy
ASC	FASB Accounting Standards Codification
ASU	FASB Accounting Standards Update
B&E	blend and extend
Bcf/d	billion cubic feet per day
BPS	bulk-power system
Btu	British thermal unit
C&DI	SEC Compliance and Disclosure Interpretation
CAES	compressed-air energy storage
CAIR	Clean Air Interstate Rule
CAISO	California Independent System Operator
CAQ	Center for Audit Quality
CCED	centrally cleared energy dispatch
CCR	coal combustion residual
CECL	current expected credit loss
CEO	chief executive officer
CFTC	U.S. Commodity Futures Trading Commission
CIAC	contribution in aid of construction
CIP	Critical Infrastructure Protection
CMR	conflict minerals report
CO₂	carbon dioxide
COFECE	Mexico's Comisión Federal de Competencia Económica
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

Abbreviation	Description
DAS	FERC's Office of Enforcement Division of Analytics and Surveillance
DCPSC	District of Columbia Public Service Commission
DER	distributed energy resource
DERP	distributed energy resource provider
DHS	Department of Homeland Security
DOE	U.S. Department of Energy
DOI	FERC's Office of Enforcement Division of Investigations
DPT	delivered price test
DRC	Democratic Republic of the Congo
DSPP	distributed system platform provider
DTA	deferred tax asset
DTL	deferred tax liability
e21	Minnesota 21st Century Energy System
EBITDA	earnings before interest, taxes, depreciation, and amortization
ED	exposure draft
EDGAR	SEC's Electronic Data Gathering, Analysis, and Retrieval system
EEl	Edison Electric Institute
EERS	energy efficiency resource standard
EGC	emerging growth company
EGU	electric generating unit
EIA	U.S. Energy Information Administration
EIM	Western U.S. Energy Imbalance Market
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
ERO	Electric Reliability Organization
FAQs	frequently asked questions
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FIFO	first-in, first out

Abbreviation	Description
FinREC	AICPA's Financial Reporting Executive Committee
FVTNI	fair value through net income
GAAP	generally accepted accounting principles
GAO	Government Accountability Office
GDP	gross domestic product
GP	general partner
GW	gigawatt
HLBV	hypothetical liquidation at book value
HPUC	Hawaii Public Utilities Commission
HTM	held to maturity
IAS	International Accounting Standard
IASB	International Accounting Standards Board
ICFR	internal control over financial reporting
IFRS	International Financial Reporting Standard
IPO	initial public offering
IPSA	independent private-sector audit
IRC	Internal Revenue Code
IRS	Internal Revenue Service
ISO	Independent System Operator
ISO-NE	ISO New England Inc.
ITC	investment tax credit
kWh	kilowatt hour
LCM	lower of cost or market
LGD	loss given default
LIFO	last-in, first-out
LIHTC	low-income housing tax credit
LLC	limited liability company
LMP	locational marginal pricing
LNG	liquefied natural gas
LNBM	locational net benefits methodology
LP	limited partner
LPG	liquid petroleum gas
M&A	mergers and acquisitions
MACRS	modified accelerated cost recovery system
MATS	Mercury and Air Toxics Standards
MD&A	Management's Discussion and Analysis
MISO	Midcontinent ISO
MLP	master limited partnership

Abbreviation	Description
MMBtu	million Btu
MMBtu/h	million Btu per hour
MoU	Memorandum of Understanding
MPSC	Mississippi Public Service Commission
MTC	minimum tax credit
MW	megawatt
MWh	megawatt hour
NAAQS	National Ambient Air Quality Standards
NAV	Notice of Alleged Violation
NEI	Nuclear Energy Institute
NEM	net energy metering
NERC	North American Electric Reliability Corporation
NETO	New England Transmission Owners
NIST	National Institute of Standards and Technology
NOL	net operating loss
NOPR	FERC Notice of Proposed Rulemaking
NO_x	nitrogen oxides
NPNS	normal purchase normal sale
NRC	Nuclear Regulatory Commission
NRV	net realizable value
NWPP	Northwest Power Pool
NYISO	New York ISO
NYPSC	New York Public Service Commission
NY REV	New York Reforming the Energy Vision initiative
O&M	operations and maintenance
OCI	other comprehensive income
OCIE	SEC's Office of Compliance Inspections and Examinations
OE	FERC Office of Enforcement
OMB	Office of Management and Budget
OSC	Order to Show Cause
P&U	power and utilities
PBE	public business entity
PCAOB	Public Company Accounting Oversight Board
PCC	FASB's Private Company Council
PCI	purchased credit-impaired
PD	probability of default

Abbreviation	Description
PEMEX	Petróleos Mexicanos
PEO	principal executive officer
PG&E	Pacific Gas and Electric Company
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
PTC	production tax credit
PTO	participating transmission owner
PUCT	Public Utility Commission of Texas
PV	photovoltaic
QPE	qualified progress expenditure
QRM	qualified residential mortgage
RA	resource adequacy
RCC	readily convertible to cash
REC	renewable energy certificate
REIT	real estate investment trust
Rev. Proc.	IRS Revenue Procedure
RFC	request for comment
RIM	retail inventory method
ROE	return on equity
ROU	right of use

Abbreviation	Description
RPS	renewable portfolio standard
RRWG	revenue recognition working group
RSV	reliability safety valve
RTO	Regional Transmission Organization
SAB	SEC Staff Accounting Bulletin
SAC	subjective acceleration clause
SEC	Securities and Exchange Commission
SIFMA	Securities Industry and Financial Markets Association
SIL	simultaneous transmission import limit
SNL	SNL Energy
SO₂	sulfur dioxide
SPP	Southwest Power Pool Inc.
SPR	strategic petroleum reserve
TCC	turbine completion certificate
TRG	transition resource group
TSR	total shareholder return
TVA	Tennessee Valley Authority
VIE	variable interest entity
WPSC	Wisconsin Public Service Commission
XBRL	eXtensible Business Reporting Language
XML	eXtensible Markup Language

The following is a list of short references for the Acts mentioned in this publication:

Abbreviation	Act
CISA	Cybersecurity Information Sharing Act of 2015
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
NEPA	National Environmental Policy Act
PATH Act	Protecting Americans From Tax Hikes Act of 2015
PURPA	Public Utility Regulatory Policies Act of 1978
Recovery Act	American Recovery and Reinvestment Act of 2009
SB 350	California Senate Bill 350, Clean Energy and Pollution Reduction Act of 2015
Securities Act	Securities Act of 1933

Appendix B — Titles of Standards and Other Literature

The titles of the standards and other literature referred to in this publication are available from the sources below.

AICPA

AT Section 101, “Attest Engagements”

AT Section 201, “Agreed-Upon Procedures Engagements”

FASB ASC References

For titles of *FASB Accounting Standards Codification* references, see Deloitte’s “Titles of Topics and Subtopics in the *FASB Accounting Standards Codification*.”

FASB Accounting Standards Updates and Other FASB Literature

See the FASB’s Web site for the titles of:

- [Accounting Standards Updates](#).
- [Proposed Accounting Standards Updates](#) (exposure drafts and public comment documents).
- [Pre-Codification literature](#) (Statements, Staff Positions, EITF Issues, and Topics).
- [Concepts Statements](#).

SEC C&DI Topics

FAST Act

Regulation A

SEC Concept Release

33-9862, *Possible Revisions to Audit Committee Disclosures*

SEC Final Rules

34-73407, *Credit Risk Retention*

34-67716, *Conflict Minerals*

33-9877, *Pay Ratio Disclosure*

33-9849, *Adoption of Updated EDGAR Filer Manual*

33-9741, *Amendments for Small and Additional Issues Exemptions Under the Securities Act (Regulation A)*

SEC Interim Final Rule

33-10003, *Simplification of Disclosure Requirements for Emerging Growth Companies and Forward Incorporation by Reference on Form S-1 for Smaller Reporting Companies*

SEC and CFTC Interpretive Release

34-74936, *Forward Contracts With Embedded Volumetric Optionality*

SEC Proposed Rules

34-74835, *Pay Versus Performance*

34-74834, *Application of Certain Title VII Requirements to Security-Based Swap Transactions Connected With a Non-U.S. Person's Dealing Activity That Are Arranged, Negotiated, or Executed by Personnel Located in a U.S. Branch or Office or in a U.S. Branch or Office of an Agent*

33-9861, *Listing Standards for Recovery of Erroneously Awarded Compensation*

33-9723, *Disclosure of Hedging by Employees, Officers and Directors*

33-9693, *Changes to Exchange Act Registration Requirements to Implement Title V and Title VI of the JOBS Act*

SEC Division of Corporation Finance Financial Reporting Manual

Topic 1, "Registrant's Financial Statements," paragraphs 1320.3 and 1320.4

Topic 2, "Other Financial Statements Required," paragraph 2030.4

SEC Forms

Form 8-K, "Current Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934": Item 2.01, "Completion of Acquisition or Disposition of Assets"

Form 10-K, "General Form of Annual Report"

Form F-1, "Registration Statement for Securities of Certain Foreign Private Issuers"

Form S-1, "Registration Statement Under the Securities Act of 1933"

Form S-11, "Registration of Securities of Certain Real Estate Companies"

Form SD, "Specialized Disclosure Report"

SEC Guidance

Amendments to Regulation A: A Small Entity Compliance Guide

SEC Office of Compliance Inspections and Examinations

Examination Priorities for 2015

Risk Alert, Vol. IV, Issue 4, *Cybersecurity Examination Sweep Summary*

SEC Regulations

Regulation A, "Conditional Small Issues Exemption"

Regulation D, "Rules Governing the Limited Offer and Sale of Securities Without Registration Under the Securities Act of 1933"

Regulation D, Rule 501(a), "Definitions and Terms Used in Regulation D: Accredited Investor"

Regulation G, "General Rules Regarding Disclosure of Non-GAAP Financial Measures"

Regulation S-K:

- Item 301, “Selected Financial Data”
- Item 303, “Management’s Discussion and Analysis of Financial Condition and Results of Operations”
- Item 402, “Executive Compensation”

Regulation S-X:

- Rule 3-05, “Financial Statements of Businesses Acquired or to Be Acquired”
- Rule 3-09, “Separate Financial Statements of Subsidiaries Not Consolidated and 50 Percent or Less Owned Persons”
- Rule 3-10, “Financial Statements of Guarantors and Issuers of Guaranteed Securities Registered or Being Registered”
- Rule 3-16, “Financial Statements of Affiliates Whose Securities Collateralize an Issue Registered or Being Registered”
- Rule 4-08(e), “General Notes to Financial Statements: Restrictions Which Limit the Payment of Dividends by the Registrant”
- Rule 5-02(13), “Commercial and Industrial Companies: Balance Sheets: Assets and Other Debits: Property, Plant and Equipment”
- Rule 5-03(b)(1), “Commercial and Industrial Companies: Income Statements: Net Sales and Gross Revenues”
- Rule 5-03(b)(2), “Commercial and Industrial Companies: Income Statements: Costs and Expenses Applicable to Sales and Revenues”
- Rule 5-04, “Commercial and Industrial Companies: What Schedules Are to Be Filed”
- Rule 12-04, “Condensed Financial Information of Registrant”

SEC Staff Accounting Bulletins

Topic 5.J, “New Basis of Accounting Required in Certain Circumstances” (Removed by SAB 115)

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”

Topic 13, “Revenue Recognition”

SEC Securities Exchange Act of 1934 Rules

Rule 12g-1, “Exemption From Section 12(g)”

Rule 12g-2, “Securities Deemed to Be Registered Pursuant to Section 12(g)(1) Upon Termination of Exemption Pursuant to Section 12(g)(2) (A) or (B)”

Rule 12g-3, “Registration of Securities of Successor Issuers Under Section 12(b) or 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)”

SEC, U.S. Department of the Treasury, Federal Reserve, the Federal Reserve Bank of New York, and the U.S. Commodity Futures Trading Commission

Joint Staff Report, "The U.S. Treasury Market on October 15, 2014"

Other

17 CFR Chapter I, Commodity Futures Trading Commission, Part 144, "Procedures Regarding the Disclosure of Information and the Testimony of Present or Former Officers and Employees in Response to Subpoenas or Other Demands of a Court"

International Standards

See Deloitte Touche Tohmatsu Limited's [IAS Plus Web site](#) for the titles of:

- International Financial Reporting Standards.
- International Accounting Standards.
- [Exposure documents](#).

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Events

Utility Industry Book/Tax Differences

Washington, D.C. | March 30, 2016

For more information, please contact: USEnergyTaxSeminars@deloitte.com.

Financial Reporting for Income Taxes: Rate-Regulated Utilities

Washington, D.C. | March 31, 2016

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

Deloitte Energy Conference

Washington, D.C. | June 21–22, 2016

For more information, please contact: EnergyConference@deloitte.com.

Deloitte Oil and Gas Conference

Houston, Texas | September 21, 2016

For more information, please contact: OilandGasConference@deloitte.com.

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