Oil & Gas

Accounting, Financial Reporting, and Tax Update

January 2015

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Drastic changes have occurred in the oil and gas (O&G) sector over the past year. While oil prices were approaching $90 a barrel in January 2014 and slightly over $100 a barrel in July 2014, prices have significantly and steadily declined since then. For instance, West Texas and Brent crude prices are below $50 a barrel through the first two weeks in January 2015. The trend with natural gas prices is similar. For example, Henry Hub spot prices dropped from $4.32 per MMBtu on January 2, 2014, to below $3.00 per MMBtu in early January 2015. O&G entities will need to reevaluate their operations in this current era of lower oil and natural gas prices.

O&G entities also may need to consider the impact of certain activities, including their cost-effectiveness and environmental implications. Such activities may include using hydraulic fracturing techniques in mineral-rich shale formations across the country and the marked increase in deep water-drilling activities in the Gulf of Mexico. Further, the United States, for the first time in its history, will be a "net exporter" of liquefied natural gas (LNG) upon the construction of liquefaction terminals that are due to go online in 2015.

The O&G sector will also be affected by various regulations and laws. For instance, President Obama's Clean Power Plan will limit power generation by coal-fired plants, thereby increasing the need for natural gas; the Department of Transportation's proposed railcar rules may directly affect how oil and natural gas is transported in the continental United States; and the controversial Keystone XL Pipeline extension law, if passed, may affect the volumes of oil that are available in the United States.

Be on the lookout for Deloitte's forthcoming *Oil & Gas Spotlight* for a discussion of navigating the changing business environment in the O&G sector.

About This Document

We are pleased to present our 2nd annual Accounting, Financial Reporting, and Tax Update for the O&G sector. This publication discusses accounting, tax, and regulatory matters that O&G entities will need to consider, including updates to SEC, FASB, IFRS, and tax guidance, and focuses on specialized industry accounting topics that frequently affect O&G entities. New to this year's publication are sections on accounting and reporting considerations related to (1) the FASB's and IASB's new revenue standard and (2) carve-out financial statements.

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

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

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Section 1
Accounting Standards Codification Update

Reporting of Discontinued Operations

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

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

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

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

Thinking It Through

Whether an O&G 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, an O&G entity that applies the successful-efforts method of accounting will need to use judgment in determining whether a strategic shift has occurred. Further, although O&G entities that use the full-cost method of accounting may not be affected by ASU 2014-08's recognition and measurement provisions, they may be required to provide additional disclosures.

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.

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.

The new guidance is likely to have the greatest impact on O&G entities that enter into routine capital market and disposal transactions.

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

Effective Date and Transition

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

Going Concern

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

Under U.S. GAAP, an entity's financial reports reflect its assumption that it will continue as a going concern until liquidation is imminent.[1] 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[2] 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.

1 In accordance with ASC 205-30, an entity must apply the liquidation basis of accounting once liquidation is deemed imminent.
2 PCAOB AU Section 341, *The Auditor's Consideration of an Entity's Ability to Continue as a Going Concern.*

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

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

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

Effective Date

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

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

Development-Stage Entities

On June 10, 2014, the FASB issued ASU 2014-10, which eliminates the concept of a development-stage entity[3] (DSE) from U.S. GAAP.[4] Specifically, the ASU removes:

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

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

Thinking It Through

ASU 2014-10 could affect O&G entities with investees that are currently determined to be DSEs in accordance with ASC 915. Such entities that are, for example, involved in the beginning stages of constructing a midstream asset may have been presenting financial statements as DSEs. O&G investors will have to assess their consolidation of such entities if they have an interest in a DSE.

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

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

[4] The ASU notes that users of DSE financial statements do not find "the [DSE] distinction, the inception-to-date information, and certain other disclosures [that DSEs are currently required to provide] decision useful."

Service Concession Arrangements

On January 23, 2014, the FASB issued ASU 2014-05 in response to the final consensus on Issue 12-H[5] reached by the EITF at its November 2013 meeting. The ASU prohibits an operating entity from accounting for certain service concession contracts as a lease under ASC 840 and from recognizing a grantor's infrastructure (e.g., transmission or distribution assets of a municipality) as property, plant, or equipment in its statement of financial position. Entities should consult other ASC topics for guidance on accounting for various components of a service concession contract (e.g., the guidance in ASC 605 on recognizing revenue resulting from the operating entity's performance under a service concession contract).

Scope

ASU 2014-05 affects operating entities that enter into service concession arrangements[6] with a public-sector entity grantor to provide a public service by operating the grantor's infrastructure. For example, a government or regulatory agency may enter into a service concession arrangement (e.g., an operating license or a similar arrangement) with an O&G entity in which the government or agency monetizes or outsources the O&G supply to meet consumer demands. To qualify as a service concession arrangement, an arrangement must meet both of the following criteria:

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

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

Transition and Effective Date

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

Pushdown Accounting

On November 18, 2014, the FASB issued ASU 2014-17 in response to the final consensus on Issue 12-F reached by the EITF at its September 2014 meeting. Under the ASU, an acquired entity[7] has the option of applying pushdown accounting (i.e., establishing a new accounting and reporting basis) in its stand-alone financial statements upon a change-in-control event. Specifically, an acquired entity that elects pushdown accounting would apply the measurement principles in ASC 805 to push down the measurement basis of its acquirer to its stand-alone financial statements. In addition, the acquired entity would be required to provide disclosures that enable financial statement users "to evaluate the nature and effect of the pushdown accounting."[8]

[5] See Deloitte's November 2013 *EITF Snapshot* for additional information about EITF Issue 12-H.

[6] Service concession arrangements within the scope of ASC 980 are outside the scope of ASU 2014-05 and should continue to be accounted for under ASC 980.

[7] The ASU's scope includes both public and nonpublic acquired entities, regardless of whether such an entity is a business or a nonprofit activity.

[8] Entities would achieve that disclosure objective by providing the relevant disclosures required by ASC 805.

Under ASU 2014-17, when an acquired entity elects to apply pushdown accounting, it would be:

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

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

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

The ASU's amendments became effective upon issuance.

Thinking It Through

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

Consolidation

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

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

Limited Partnerships (and Similar Entities)

Determining Whether a Limited Partnership Is a VIE

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

Consolidation of a Limited Partnership

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

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

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

Thinking It Through

Like entities in other industries, O&G entities will need to assess their existing organizational structures (e.g., transactions involving investors in master limited partnership midstream developments) to determine the impact of this guidance.

O&G entities will also need to review the partnership agreements of limited partnerships and similar entities that are currently considered VIEs (i.e., ensure that the conditions in ASC 810-10-15-14 have been satisfied) to determine whether they contain substantive majority kick-out or participating rights.

Identifying the Primary Beneficiary of a VIE

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

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

- "[I]f a decision maker owns a 40 percent interest in a related party and that related party owns a 60 percent interest in the entity being evaluated, the decision maker's interest would be considered equivalent to a 24 percent direct interest in the entity for the purposes of evaluating its decision-making capacity (assuming it has no other relationships with the entity)."
- "[I]f an employee of the decision maker is a related party and owns an interest in the entity being evaluated and that employee's interest has been financed by the decision maker, the decision maker shall include its indirect interest in the evaluation."

However, the Board also decided that if the reporting entity and its related party are under common control, the related party's entire economic interest should be included in the reporting entity's analysis of whether it (1) has a variable interest in the entity and (2) is the primary beneficiary of the VIE.

Effects of Related Parties

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

The FASB tentatively decided that in a manner consistent with these requirements, each party in a related-party group must first determine whether it individually has the characteristics of a controlling financial interest in the VIE. The FASB also decided to retain the current guidance under which parties in a related-party group (including de facto agents) cannot conclude that they do not individually have these characteristics because they consider power to be shared among them. Accordingly, when power is considered "shared," the related parties would be required to perform the related-party tiebreaker test to identify the party in the group that is most closely associated with the VIE. O&G entities that enter into joint venture arrangements that are considered VIEs therefore may need to perform the related-party tiebreaker test if the other venturer is considered a related party (e.g., a de facto agent) of the reporting entity.

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

The FASB also tentatively decided that if neither the decision maker nor a related party under common control is required to consolidate a VIE but the related-party group (including de facto agents) possesses the characteristics of a controlling

[9] The term "related parties" encompasses parties identified as related parties in ASC 850 and certain other parties described in ASC 810-10-25-43 that are considered de facto agents of the reporting entity.

financial interest and substantially all of the VIE's activities are conducted on behalf of a single entity in the related-party group, that entity would be the primary beneficiary of the VIE.

Effective Date and Transition

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

Thinking It Through

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

Leases

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

Thinking It Through

The boards have spent a significant amount of time trying to define a lease arrangement to help entities determine whether an arrangement contains a lease or represents an agreement to provide a service. The boards' revised leases ED, released by the FASB as a proposed ASU in May 2013, defines a lease as "a contract that conveys the right to use an asset (the underlying asset) for a period of time in exchange for consideration." The revised ED focuses on whether (1) the contract is based on an identified asset and (2) the lessee obtains the right to control the use of the asset for a particular period. The definition in the revised ED represented a significant departure from the current guidance in ASC 840, under which a customer's control of the outputs of an identified asset is considered sufficiently representative of a lease of that asset (e.g., a power purchase agreement, in which the off-taker purchases substantially all of the outputs of a generating facility).

The boards' final definition of a lease will have a significant impact on whether an arrangement is within the scope of the new guidance. This determination may be particularly difficult for O&G entities, which may enter into farmout agreements or drilling contracts that contain a lease arrangement.

Lessee Accounting

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

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

Thinking It Through

Unlike the current criteria in ASC 840, the lease classification criteria in IAS 17 are not "bright lines." Therefore, it is possible that operating leases that currently meet the bright-line criteria in ASC 840 could be considered Type A leases under the FASB's proposed dual-model approach. O&G entities would need to carefully reassess the classifications of their leases, including classifications for leases of oilfield equipment and other assets, and consider whether their patterns of expense recognition would be affected by the proposed guidance.

Lessor Accounting

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

Next Steps

The FASB and IASB are expected to complete their redeliberations of the proposed lease guidance in early 2015 and, although they have not indicated a release date, are likely to issue final guidance during the second half of 2015. Likewise, although the boards have not indicated when the final guidance would be effective, a date as early as January 1, 2018, is possible. See Deloitte's March 27, 2014, *Heads Up* for additional information about the boards' tentative decisions regarding the proposed lessee and lessor accounting models. In addition, this spring we are planning to issue an *Oil & Gas Spotlight* detailing the impact of the proposed leases model on O&G entities.

Thinking It Through

Lease accounting changes could have a significant impact on O&G entities, including their:

- *Systems* — For instance, an O&G entity may need to implement an IT system to maintain lease activity or update its legacy systems in light of the new standard.
- *Business decisions* — Examples of business decision changes include (1) evaluation of an existing debt covenant to ensure that no new liabilities are in violation of the covenant and (2) more careful scrutiny of "lease vs. buy" decisions.
- *Financial reporting* — New model will result in increased disclosures and greater need to to use judgment in determining whether an arrangement contains a lease and how Type A and Type B leases should be classified.

Financial Instruments — Classification and Measurement

Recent Redeliberations

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

Classification and Measurement of Equity Investments

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

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

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

a. A significant deterioration in the earnings performance, credit rating, asset quality, or business prospects of the investee

b. A significant adverse change in the regulatory, economic, or technological environment of the investee

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

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

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

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

Thinking It Through

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

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

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

Under the FASB's tentative approach, an entity would measure the portion of the change in fair value attributable to instrument-specific credit risk as the excess of the total change in fair value over the change in fair value "resulting from a change in a base market risk, such as a risk-free interest rate." However, "an entity may use [an alternative] method that it considers to more faithfully represent the portion of the total change in fair value resulting from a change in instrument-specific credit risk." In either case, the entity would be required to disclose the method it "used to determine the gains and losses attributable to instrument-specific credit risk and [to] apply the method consistently from period to period."[10]

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

Next Steps

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

Financial Instruments — Hedging

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

- Hedge effectiveness requirements.
- Whether the shortcut and critical-terms-match methods should be eliminated.
- Voluntary dedesignations of hedging relationships.
- Recognition of ineffectiveness for cash flow underhedges.
- Hedging components of nonfinancial items (e.g., a gas midstream entity may hedge its exposure to changes in the price of gas at a liquid trading hub, such as the NYMEX Henry Hub, even though its forecasted sales obligation is for delivery at a location in Louisiana not accessed through a more liquidly traded delivery hub).

[10] Quoted text is from a handout for the April 23, 2014, FASB meeting.

- Benchmark interest rates.
- Simplification of hedge documentation requirements.
- Presentation and disclosure matters.

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

Financial Instruments — Impairment

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

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

CECL Model

Scope

The CECL model[12] would apply to most[13] debt instruments (other than those measured at FVTNI), such as lease receivables, reinsurance receivables that result from insurance transactions, financial guarantee contracts, and loan commitments. However, AFS debt securities would be outside the model's scope and would continue to be assessed for impairment under ASC 320.

Recognition of Expected Credit Losses

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

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

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

[13] The CECL model would not apply to the following debt instruments:

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

Thinking It Through

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

Measurement of Expected Credit Losses

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

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

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

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

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

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

Available-for-Sale Debt Securities

In August 2014, the FASB tentatively decided that AFS debt securities would be outside the scope of the CECL model and would continue to be accounted for under ASC 320. However, the FASB tentatively decided to revise ASC 320 by:

- Requiring an entity to use an allowance approach (as opposed to permanently writing down the security's cost basis).

- Removing the requirement for an entity to 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 for an entity to consider recoveries in fair value after the balance sheet date when assessing whether a credit loss exists.

Disclosures

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

- Credit quality.[14]
- Allowance for expected credit losses.
- Policy for determining write-offs.
- Past-due status.
- Purchased credit-impaired assets.
- Collateralized financial assets.
- Collateral-dependent financial assets.
- Policies for accounting for nonaccrual financial assets.

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

Next Steps

The Board expects to discuss additional matters related to disclosures, transition, and effective date at a future meeting. Be on the lookout for Deloitte's forthcoming *Oil & Gas Spotlight* for a discussion of certain developments in the O&G sector, including impairment considerations.

Effects on Earnings per Unit of Master Limited Partnership Dropdown Transactions

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

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

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

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

Thinking It Through

MLPs are common structures used in the O&G industry, typically for pipeline and upstream businesses, which earn stable income from the transport of oil, gasoline, or natural gas, and businesses involved in storage, terminals, and processing plants. This proposal may have a direct impact on such entities.

ASC 260 does not address how a dropdown transaction that occurs after the MLP's initial formation and that is accounted for as a reorganization of entities under common control would affect the MLP's presentation of historical EPU. As a result, two common approaches have developed in practice:

- Restate historical EPU "by allocating the net income (loss) of the transferred business prior to the date of the dropdown transaction to the GP, LPs, and [other participating interest] holders as if their rights to that income (loss) were consistent with their contractual rights after the dropdown transaction has occurred."
- Allocate "the net income (loss) of the transferred business prior to the date of the dropdown transaction entirely to the GP." Under this alternative, there is no retrospective adjustment to previously reported EPU for LP units.

Under the proposed ASU, the first approach would no longer be allowed.

FASB's Disclosure Framework

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. See Deloitte's July 17, 2012, *Heads Up* for additional information.

The FASB subsequently decided to distinguish between the "FASB's decision process" and "entity's decision process" for evaluating disclosure requirements.

FASB's Decision Process

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

Summary of Comment-Letter Feedback

Comments on the proposed concepts statement were due by July 14, 2014. The FASB received over 50 comment letters from various respondents, including preparers, professional and trade organizations, and accounting firms. Respondents generally expressed support for the development of a conceptual framework for use in evaluating disclosure requirements that would apply to existing and future standards.

However, many respondents were concerned that the ED's "intentionally broad" proposed decision questions may result in excessive disclosures. Such respondents therefore suggested that the FASB use a filtering mechanism (e.g., based on cost and decision-usefulness) to further narrow disclosure requirements.

Respondents also suggested that the FASB clarify the difference between relevance and materiality and align the definition of materiality in the FASB's concepts statement with that established by the Supreme Court.[15] Accordingly, the FASB has tentatively decided that the concepts statement will state that materiality is a jurisdiction-based legal determination and will refer to the Supreme Court's decision as an example.

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

Next Steps

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

Entity's Decision Process

Topic-Specific Disclosure Reviews

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

ASC Topic	Status
820 (fair value measurement)	Testing in progress. Results discussed with the Board.
330 (inventory)	Not started.
715 (defined benefit plans)	Testing in progress. Results discussed with the Board.
740 (income taxes)	Testing in progress. Partial results discussed with the Board.

A proposed ASU could be issued as a result of this process.

Interim Reporting

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

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

FASB's Simplification Initiative

Simplifying Income Statement Presentation by Eliminating the Concept of Extraordinary Items

On January 9, 2015, the FASB issued ASU 2015-01, which eliminates the concept of an extraordinary item from U.S. GAAP. To be considered an extraordinary item under existing U.S. GAAP, an event or transaction must be unusual in nature and must occur infrequently. Under the ASU, an entity will no longer (1) segregate an extraordinary item from the results of

[15] Paragraph QC11 in the third chapter of FASB Concepts Statement 8 states that "[i]nformation is material if omitting it or misstating it could influence decisions that users make on the basis of the financial information of a specific reporting entity." Further, PCAOB Auditing Standard 11 explains that "[i]n interpreting the federal securities laws, the Supreme Court of the United Stated has held that a fact is material if there is 'a substantial likelihood that the . . . fact would have been viewed by the reasonable investor as having significantly altered the 'total mix' of information made available. As the Supreme Court has noted, determinations of materiality require 'delicate assessments' of the inferences a 'reasonable shareholder' would draw from a given set of facts and the significance of those inferences to him" (footnotes omitted).

[16] *TSC Industries v. Northway, Inc.*, 426 U.S. 438, 449 (1976). See also *Basic, Inc., v. Levinson*, 485 U.S. 224 (1988).

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.

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.

For more information, see Deloitte's January 12, 2015, *Heads Up*.

Debt Issuance Costs

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

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

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

Liabilities and Equity — Short-Term Improvements

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

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

Private-Company Standard Setting

Definition of a Public Business Entity

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

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

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

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

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

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

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

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

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

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

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

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

Thinking It Through

An O&G entity may need to carefully examine the circumstances related to both its financial statement requirements and any restrictions on the transfer of its securities in determining whether it satisfies any of the PBE criteria. Many O&G entities will meet the definition of a PBE.

Accounting Alternatives for Private Companies

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

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

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

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

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

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

Thinking It Through

Regardless of their eligibility under U.S. GAAP to elect private-company alternatives, entities may receive input from their regulators about whether electing such alternatives is acceptable.

Section 2
Introducing a New Revenue Model

Background

On May 28, 2014, the FASB and IASB issued their final standard on revenue from contracts with customers. The standard, issued as ASU 2014-09 by the FASB and as IFRS 15 by the IASB, outlines a single comprehensive model for entities to use in accounting for revenue arising from contracts with customers and supersedes most current revenue recognition guidance,[1] including industry-specific guidance such as that for O&G entities in ASC 932-605.

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

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

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

Key Accounting Issues

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

Thinking It Through

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

[1] The SEC has indicated that it plans to review and update the revenue recognition guidance in SAB Topic 13, "Revenue Recognition," in light of the ASU. The extent to which the ASU's guidance will affect a public entity will depend on whether the SEC removes or amends the guidance in SAB Topic 13 to be consistent with the new revenue standard.

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

Commodity Exchange Arrangements

Scope Considerations

Commodity exchange arrangements are common in the O&G 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 liquids (NGLs) are exchanged at different storage hubs). Entities usually enter into commodity exchange arrangements to meet the operational needs of the business without incurring any ancillary costs (e.g., transportation costs).

Generally, the purpose of exchange arrangements is to allow the parties to meet the needs of the market; therefore, the parties 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 and would be accounted for in accordance with ASC 845. Therefore, the new revenue model is not expected to have a significant impact on commodity exchange arrangements if they are currently accounted for as like-kind exchanges.

Thinking It Through

In certain arrangements, a marketer may agree to sell crude oil or gas to a refiner or gas processor and simultaneously buy back separate, refined products such as condensates or NGLs. O&G entities should be aware that although such agreements may be structured similarly to the commodity exchange arrangements discussed above, the applicability of the ASU to the two types of arrangements may differ. For example, O&G entities may need to assess whether the refining or processing counterparty meets the definition of a customer or whether the arrangement should be accounted for under other GAAP. Further, under certain contracts related to the processing of NGLs, the performance obligation may be met upon the completion of the processing activity rather than when the processor ultimately sells the NGLs.

Production Imbalances

Production imbalances in a well arise when working interest owners in a production-sharing arrangement sell more ("overlift") commodity production in a given period than they are entitled to sell according to their working interest ownership percentages. The overlift party thus has an obligation to settle the imbalance with the underlift party financially or in kind by the end of the property's life.

Current guidance in ASC 932-10-S99-5 generally permits owners to record revenue related to a production-sharing arrangement by using either the entitlements method or the sales method. Under the entitlements method, an owner generally records revenue equivalent to its share of production and a payable (overlift) or receivable (underlift) for the difference between volumes it actually sold to third parties and its working interest. Under the sales method, an owner generally records revenue for the actual amount of the production sold to third parties and adjusts reserves for any shortfall.

Identifying the Contract With the Customer

If the sales contract with the third party is considered a contract with a customer,[3] revenue on those sales would be recognized in accordance with the new model. Further, while the SEC staff's accounting guidance on the sales and entitlements methods (ASC 932-10-S99-5) remains in effect, it does not preclude the underlift party from accounting for the production imbalance under the new revenue model if the overlift party meets the definition of a customer in the ASU.

O&G entities should consider whether an underlift party's production imbalance with an overlift party constitutes a contract with a customer that should be accounted for under ASU 2014-09 or whether the SEC industry guidance in ASC 932-10-S99-5 would be more applicable. If an O&G entity determines that a production imbalance should be accounted for under

[3] ASU 2014-09 defines a customer as "a party that has contracted with an entity to provide goods or services that are an output of an entity's ordinary activities in exchange for consideration."

the ASU, it should consider the potential applicability of the considerations discussed below, including volumetric optionality (see Volumetric Optionality below).

Thinking It Through

The ASU does not amend the SEC's guidance in ASC 932-10-S99-5, which states that both the sales and entitlements methods of accounting for production imbalances are acceptable. However, because the SEC has indicated its intention to review the revenue recognition guidance in SAB topics, O&G entities should continue to monitor this guidance for any potential changes.

Blend-and-Extend Contract Modifications

Contract Modifications

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

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

Blend-and-Extend Contract Modifications

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

Potential Impact of New Revenue Model

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

Distinct Performance Obligations

Identifying the Performance Obligations in the Contract

The ASU provides guidance on evaluating the promised "goods or services"[4] 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."

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 crude oil for which delivery of the same product is required over time would be treated as a single performance obligation satisfied continuously throughout the contract if it meets the above criteria. In this case, the entity would determine an appropriate method for measuring progress toward complete satisfaction of the single performance obligation (i.e., the transfer of control of the promised goods over time) and would recognize the transaction price as revenue as progress is made.

Variable Pricing

Determining the Transaction Price

The ASU requires that variable consideration be included in the transaction price under certain circumstances. An estimate of variable consideration is only included in the transaction price to the extent that it is probable[5] that subsequent changes in the estimate would not result in a "significant reversal" of revenue. This concept is commonly referred to as the "constraint." The ASU requires entities to perform a qualitative assessment that takes into account the likelihood and magnitude of a potential revenue reversal and provides factors that could indicate that an estimate of variable consideration is subject to significant reversal (e.g., susceptibility to factors outside the entity's influence, long period before uncertainty is resolved, limited experience with similar types of contracts, practices of providing concessions, or a broad range of possible consideration amounts). This estimate would be updated in each reporting period to reflect changes in facts and circumstances.

The use of variable consideration (e.g., index or formula-based pricing), as well as uncertainty regarding delivery quantity, may present challenges related to estimating and allocating the transaction price and applying the ASU's constraint guidance. 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 will be entitled. In addition, the constraint does not apply to sales- or usage-based royalties derived from the licensing of intellectual property; rather, consideration from such royalties is only recognized as revenue at the later of when the performance obligation is satisfied or when the uncertainty is resolved (e.g., when subsequent sales or usage occurs).

[4] 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.

[5] "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." This is also consistent with the term "probable" in step 1 regarding the collectibility threshold. See Deloitte's May 28, 2014, *Heads Up* for more information on collectibility.

Thinking It Through

Under current U.S. GAAP, the amount of revenue recognized is generally limited to the amount that is not contingent on a future event (i.e., the price is fixed or determinable). Under the ASU, an entity must include some or all of an estimate of variable (or contingent) consideration in the transaction price (which is the amount to be allocated to each unit of account and recognized as revenue) when the entity concludes that it is probable that changes in its estimate of such consideration will not result in significant reversals of revenue in subsequent periods. The guidance in the ASU, which is generally less restrictive, is likely to result in earlier revenue recognition than the guidance in current U.S. GAAP. To comply with the ASU's requirements for estimating the transaction price and determining what amount, if any, is subject to potential reversal (and should be excluded from the transaction price), management may need to use significant judgment, particularly since the transaction price must be updated in each reporting period.

Significant Financing Component

Determining the Transaction Price

Adjustments for the time value of money are required if the contract includes a "significant financing component" (as defined in the ASU). Generally, no adjustment is necessary if payment is expected to be received within one year of the transfer of goods or services to the customer. However, if an entity concludes, on the basis of the payment terms, that there is a significant financing component, it should adjust the sales price when recording revenue to present the amount that would have been attained had the buyer paid cash for the goods or services on the date of sale.

Thinking It Through

Payment terms in the O&G industry often include up-front fees or extended payment terms (e.g., long-term volumetric production payments). Under current guidance, arrangements that offer extended payment terms often result in the deferral of revenue recognition since the fees are typically not considered fixed or determinable unless the entity has a history of collecting fees under such payment terms without providing any concessions. In the absence of such a history, revenue is recognized when payments become due or when cash is received from the customer, whichever is earlier. Typically, under current accounting requirements, there would be no adjustment for advanced payments.

Under the ASU, if the financing term extends beyond one year and a significant financing component is identified, the entity would need to initially estimate the transaction price by incorporating the impact of any potential price concessions (see discussion above in Variable Pricing) and then adjust this amount to account for the time value of money. That amount, adjusted for any concessions and the time value of money, would then be recognized as revenue when the entity transfers control of the good or service to the customer. When the entity is providing financing, interest income would be recognized as the discount on the receivable unwinds over the payment period. However, when the entity receives an up-front fee, the entity is deemed to be receiving financing from the customer and interest expense is recognized, with a corresponding increase to revenue recognized. This recognition pattern may differ significantly from the pattern under current U.S. GAAP, as described above.

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. Natural gas and other commodity off-take contracts are commonly structured as take-or-pay. Service arrangements, such as those for natural gas storage or transportation, can also be structured as take-or-pay.

Identifying the Performance Obligations in the Contract

Under the ASU, a supplier in a take-or-pay arrangement would generally conclude that it has entered into a contract with a customer to deliver a series of distinct, but substantially the same, goods consecutively over time (see discussion above in Distinct Performance Obligations). Therefore, the supplier should account for that series of distinct goods as a single performance obligation — and as a single unit of account — when both of the following two criteria are met:

- The customer simultaneously receives and consumes the benefits of each distinct delivery of natural gas or other commodity (i.e., the delivery of natural gas 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 natural gas or other commodity (e.g., a time- or 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 involving monthly deliveries of natural gas in which the customer pays irrespective of whether it takes delivery and cannot make up deliveries not taken. In this case, it may be appropriate for the supplier to use an output measure of progress based on time to recognize revenue because the performance obligation is satisfied as each month passes.
- In a take-or-pay arrangement involving monthly deliveries of natural gas in which the customer can make up deliveries not taken later in the contract tenor, an output measure of progress based on units delivered may be appropriate. In this case, the supplier should recognize revenue for volumes of natural gas actually delivered to the customer each month and recognize a contract liability for volumes not taken, since the supplier's performance obligation related to those volumes is unsatisfied despite receipt of customer payment. That is, the supplier would need to provide more gas in the future months to complete its promise to the customer.

Thinking It Through

Although ASU 2014-09 will supersede the industry guidance in ASC 932-605-25-2 on take-or-pay arrangements, we expect that the accounting for such arrangements will largely remain the same in practice.

Volumetric Optionality

Material Options

The ASU contains implementation guidance on recognizing revenue related to options for additional goods or services (i.e., written volumetric optionality). Upstream and marketing companies should carefully consider any additional quantities that the customer has rights to in take-or-pay or other off-take arrangements and whether such volumetric optionality represents a separate performance obligation in the contract. If a right to additional quantities results in a material right that the customer would not otherwise receive had it not entered into that contract, the option is considered a separate performance obligation. For example, a material right may be identified for additional quantities at prices that are significantly in-the-money (as determined at contract inception).

The consideration in a contract that includes options for additional goods or services may include an up-front payment. For example, that payment may reflect the present value of the difference between a fixed price for optional quantities and consideration determined by using the supplier's forward commodity price curve. When that is the case, the up-front payment is included in the overall transaction price, which would be allocated by applying the ASU's allocation method to the performance obligations identified (which may include a separate performance obligation for a material right). In addition, the entity should evaluate whether a significant financing component is present (see Significant Financing Component above).

Drilling Contracts

Whether for developing properties offshore or on land, drilling contracts are often complex, involving significant amounts of consideration and including specialized assets and service offerings in various forms (e.g., day-rate, turnkey). Drilling contractors will need to carefully evaluate whether their contracts are — or contain — leases within the scope of ASC 840.[6] If a contract (or part of a contract) is within the scope of ASC 606, the contractor should perform the steps discussed below under the new revenue model.

Identifying the Performance Obligations in the Contract

Drilling contracts often contain "mobilization" or "localization" terms under which the drilling contractor is to move an agreed-upon drilling rig and equipment from a current location to the drilling site (or sites). For example, in offshore, day-rate drilling contracts, there is often an explicit day rate for mobilization work and periods. This day rate is generally lower than the day rate for the actual drilling period and corresponding activities.

Contractors should carefully examine whether an activity in a drilling contract is a promise to transfer a good or service to a customer (i.e., a performance obligation). ASC 606-10-25-17 states the following regarding identifying a performance obligation in a contract:

> Performance obligations do not include activities that an entity must undertake to fulfill a contract unless those activities transfer a good or service to a customer. For example, a services provider may need to perform various administrative tasks to set up a contract. The performance of those tasks does not transfer a service to the customer as the tasks are performed. Therefore, those setup activities are not a performance obligation.

That is, a drilling contractor must first consider whether an activity such as mobilization is necessary to fulfill the larger drilling contract (i.e., a set-up activity) and is not a promise to deliver a service. A drilling contractor may conclude that such an activity does not constitute delivery of a service to the well operator (i.e., the customer). In this instance, the costs incurred to set up the drilling service (i.e., the mobilization activities) may be capitalized as an asset in accordance with the new contract cost provisions in ASC 340-40 if the criteria are met and the drilling contractor would not begin fulfillment of the contract with the well operator until the drilling activity commences. Also, any payments received during the mobilization activity would be recognized as a contract liability (deferred revenue) and only recognized when the contractor satisfies its obligations (i.e., performs the drilling service) for its customer (the well operator).

However, if an activity such as mobilization is a promise to deliver a service to the operator, a contractor must consider whether it is distinct and meets **both** criteria in ASC 606-10-25-19 for separate revenue recognition:

- The "service is capable of being distinct" (i.e., the operator can benefit from the service on its own or together with other resources that are readily available).
- The "service is distinct within the context of the contract" (i.e., the promise to deliver the service "is separately identifiable from other promises in the contract").

[6] Drilling contractors may also need to reevaluate their contracts upon the issuance of new lease guidance by the FASB and IASB, since such guidance could affect the determination of whether these contracts are or contain a lease.

Thinking It Through

A drilling contractor should carefully consider whether the efforts involved in the mobilization represent an activity (i.e., a set-up activity) or a service that provides a benefit to the customer. If the mobilization efforts satisfy a promise to the customer by delivering a service, the drilling contractor must determine whether that mobilization service is separable from the drilling service. In many cases, the drilling contractor will conclude that mobilization of a drilling rig does not result in a separate benefit for well operators and that the activity is thus incapable of being distinct. However, in situations in which that conclusion is inappropriate, contractors will need to determine whether mobilization is (1) both separately identifiable in the contract and distinct in the context of the contract, and thus a distinct performance obligation, or (2) a single service delivery in combination with the drilling operations.

Recognize Revenue When (or as) Performance Obligations Are Satisfied

Under the ASU, a drilling contractor is likely to conclude that its performance obligation for drilling services in a day-rate or other drilling contract is satisfied over time because the contractor's performance creates or enhances an asset (e.g., the oil well) that the customer controls as the asset is created or enhanced. That is, such a performance obligation would meet one of the criteria in ASC 606-10-25-27 to be satisfied over time. Therefore, in such cases, a drilling contractor would recognize revenue by measuring progress toward satisfying the performance obligation in a manner that best depicts the transfer of goods or services to the customer.

Certain types of fixed pricing provisions in a drilling contract may warrant a careful examination of the measure of progress to be used. Consider a two-year offshore drilling contract whose initial day rate of $500,000 increases by a fixed increment of $50,000 in each semiannual period. In contemplating the appropriate measure of progress that best depicts the transfer of its service, the contractor in this example may consider the following:

- *Output measure of progress (e.g., time, days drilled)* — As it performs, the contractor could potentially recognize an amount of revenue equivalent to the total transaction price (determined under step 3 of the new revenue model) divided by the total number of days over which services are expected to be delivered. Days during which mobilization and other activities are to be performed may be included in that calculation depending on the conclusions the contractor reaches when identifying the contract's performance obligations. A fixed day rate that increases twice per year by a fixed amount of $50,000 could be factored into the calculation of the total transaction price and recognized on a straight-line basis[7] over the tenor of the contract (i.e., at an equal amount for each day of contract delivery).

- *Input measure of progress (e.g., costs incurred)* — The contractor may recognize as revenue a percentage of the total transaction price, calculated as a ratio of the costs of drilling for the period (e.g., labor and fuel costs) to the total costs to be incurred to deliver the contract. Again, fixed pricing that increases semiannually by a fixed day rate of $50,000 could be factored into the calculation of the total transaction price. Revenue could be recognized, for example, in increasing amounts over the tenor of the contract if costs are expected to rise as the contract is delivered. This method would be affected by whether the contractor concludes that the mobilization efforts represent an activity or a performance obligation. If the efforts represent an activity, the costs would be considered set-up costs and, if they meet certain criteria, would be capitalized as an asset and then systematically amortized during the drilling service. If the mobilization efforts represent a service (a performance obligation), then the costs incurred would be included within the cost-to-cost measure of progress.

Royalty Payments

O&G entities often enter into royalty arrangements with the owners of mineral rights, which can be either private or governmental entities. Under current practice, an O&G entity extracts the commodity and remits a royalty payment to the mineral rights owner upon (1) the completion of the extraction activities or (2) the sale of the oil or gas. The nature and

[7] O&G entities should consider whether straight-line recognition related to uneven pricing provisions indicates that the customer is financing the purchase of more expensive services later in the contract. See discussion above in Significant Financing Component.

extent of the mineral owners' involvement, as well as the contractual structure of these types of arrangements, may vary. For instance, some arrangements may result in the mineral rights owner's active involvement in the production process, which may serve as a catalyst to both the lifting arrangement with the O&G entity and the sales arrangement with a third party; however, other arrangements may leave the uplifting and subsequent sales arrangements to the O&G entity. In addition, some arrangements may be based on a specified volume of oil or gas extracted at a predetermined rate, while other arrangements may require the entity to sell all of the extracted commodity to a third party and pay the mineral rights owner a proportion of aggregate transaction proceeds less certain lifting costs.[8]

Under the ASU, an O&G entity should first consider whether the contract with royalty payments is within the scope of ASC 606 (i.e., whether the counterparty is a customer rather than a collaborator and is therefore within the scope of ASC 606). If so, the entity would determine the amount of consideration it expects to be entitled to, which would exclude amounts collected on behalf of third parties. Therefore, if the entity is solely collecting amounts on a third party's behalf (e.g., the government), such amounts would not be included in the transaction price since they are effectively passed through the entity to the government. In addition, the entity should consider the ASU's implementation guidance on principal-versus-agent considerations (see Principal-Versus-Agent Considerations below) to determine whether its promise in the contract is to provide the extraction service (gross presentation) or to arrange for another party (acting as an agent) to transfer goods or services (net revenue recognition).

Collaborative Arrangements

O&G entities should assess their royalty arrangements with mineral rights owners to determine whether the arrangements are contracts with a customer or whether they are sharing in the risks and benefits under a collaborative arrangement. The ASU broadly applies to contracts with customers and defines a customer as "a party that has contracted with an entity to obtain goods or services that are an output of the entity's ordinary activities in exchange for consideration." The ASU notes:

> A counterparty to the contract would not be a customer if, for example, the counterparty has contracted with the entity to participate in an activity or process in which the parties to the contract share in the risks and benefits that result from the activity or process (such as developing an asset in a collaboration arrangement) rather than to obtain the output of the entity's ordinary activities.

In an arrangement that results in the mineral rights owner's active involvement in the production process (i.e., its input in the lifting process or involvement in executing the sales arrangement with a third party), the O&G entity might conclude that it is more of a collaborative arrangement and therefore outside the ASU's scope.

Principal-Versus-Agent Considerations

Other parties may be involved in providing goods or services to an entity's customers. In such cases, the entity must determine whether "the nature of its promise is a performance obligation to provide the specified goods or services itself (that is, the entity is a principal) or to arrange for the other party to provide those goods or services (that is, the entity is an agent)." An entity is a principal when it controls a promised good or service before the entity transfers the good or service to the customer. The ASU provides indicators and other implementation guidance to help an entity determine whether the entity is acting as a principal (revenue is recognized on a gross basis) or as an agent (revenue is recognized on a net basis).

In a principal-versus-agent determination, an O&G entity must assess the nature and terms of the arrangement. For example, it would need to determine whether its involvement in the lifting activities and subsequent delivery to a third party constitutes the fulfillment of the entity's own performance obligation to deliver goods to the customer (i.e., the entity is serving as a principal) or whether the goods are being delivered on behalf of the mineral owner (i.e., the entity is acting as an agent). This conclusion will directly affect whether revenue should be recorded gross or net (i.e., whether solely the royalty payment should be recognized as revenue).

[8] Lifting costs are generally costs associated with O&G production after drilling is complete. Lifting costs include, but are not limited to, (1) transportation costs, (2) labor costs, (3) certain supplies, and (4) cost of operating the wells.

Sales of Mineral Interests and Production Payments

ASU 2014-09 governs the amount, timing, and recognition of gains and losses from the sale of fixed assets and real property. (See Deloitte's July 2, 2014, *Heads Up* for additional considerations related to the accounting for real estate sales under the new revenue standard.) However, conveyances of mineral interests and O&G properties are outside the ASU's scope. Therefore, the industry guidance in ASC 932-360 remains in effect and, for example, an O&G entity's sale and retention of its operating and nonoperating interests in a well, respectively, would continue to be accounted for under ASC 932. However, that same entity's sale of its drilling equipment on the property would be accounted for in accordance with the ASU.

The ASU is also not expected to have a significant impact on production payments. Under ASC 932, a production payment repayable in cash plus interest out of proceeds from a specific mineral interest is considered to be a financing and not a sale of that mineral interest. However, a volumetric production payment (VPP) that is repaid in a specified amount of commodity lifted from a specific mineral interest and delivered free and clear of all expense associated with that interest's operation reflects a sale of that mineral interest. Currently, ASC 932-360 requires the seller in a VPP to record deferred revenue that is recognized as the commodity is delivered. This guidance is also outside the ASU's scope. Therefore, the accounting for VPPs is not expected to change as a result of the new revenue model.

Disclosures

The ASU requires entities to disclose both 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, which are significantly more comprehensive than those in existing revenue standards, include the following (with certain exceptions for nonpublic entities):

- 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 (1) contract assets and liabilities (including changes in those balances), (2) the amount of revenue recognized in the current period that was previously recognized as a contract liability, and (3) 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 annual 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) the transaction price allocated to the remaining performance obligations. Nonpublic entities can use certain practical expedients under the ASU to avoid providing some of the disclosures required of public entities. For additional information about the practical expedients that are available to nonpublic entities, see Deloitte's October 2014 *Oil & Gas Spotlight*.

Effective Date and Transition

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

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

- The same effective date as that for public entities (annual reporting periods beginning after December 15, 2016, including interim periods).
- Annual periods beginning after December 15, 2016 (excluding interim reporting periods).
- Annual periods beginning after December 15, 2017 (including interim reporting periods).

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

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

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

  The SEC staff in the Division of Corporation Finance (the "Division") has indicated that it would not object if the basis that a registrant uses to reflect its adoption of the new revenue standard in selected financial data (as required by Regulation S-K, Item 301) is the same as the basis that it uses to adopt the new revenue standard in its financial statements. If a registrant presents less than five years on the basis of the new revenue standard, it would need to disclose the method it used and that the prior years in the selected financial data disclosure are not comparable. See Deloitte's September 12, 2014, journal entry for more information.[9]

- *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

[9] At the 2014 AICPA Conference on Current SEC and PCAOB Developments, the Division staff noted that it will accept less than five years of revenues presented on the basis of the new revenue standard in selected financial data (i.e., it would not require a registrant to retrospectively adjust the last two years) to encourage registrants to use the full retrospective method of adoption because that method would yield information that is more useful to financial statement users. See Deloitte's December 15, 2014, *Heads Up* for more information.

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 transition 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:

January 1, 2017	2017	2016	2015
Initial Application Year	**Current Year**	**Prior Year 1**	**Prior Year 2**
New contracts	New ASU		
Existing contracts	New ASU + cumulative catch-up	Legacy GAAP	Legacy GAAP
Completed contracts		Legacy GAAP	Legacy GAAP

Thinking It Through

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

See Deloitte's October 2014 *O&G Industry Spotlight* for additional information on potential implementation challenges for O&G entities and certain other considerations for nonpublic entities.

Section 3
SEC Update

Disclosure Effectiveness

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

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

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

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

Activities Related to Requirements of the Dodd-Frank Act

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

Navigating the Conflict Minerals Rule

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

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

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

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

Security-Based Swaps

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

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

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

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

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

SEC Adopts Money Market Fund Reforms

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

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

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

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

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

The Jumpstart Our Business Startups Act

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

Small-Company Capital Formation

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

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

- Tier 1 would consist of offerings that satisfy Regulation A's current requirements.
- Tier 2 would consist of securities offered of up to $50 million in a 12-month period with no more than $15 million offered by an issuer's security holders.

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

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

Incorporating IFRSs Into U.S. Financial Reporting System

At the AICPA Conference on Current SEC and PCAOB Developments in December 2014, SEC Chief Accountant James Schnurr discussed a possible fourth alternative[3] for incorporating IFRSs into the U.S. financial reporting system. Under this potential alternative, U.S. companies would have the option of voluntarily providing IFRS-prepared financial information as a supplement to their U.S. GAAP financial statements. The information from this fourth alternative could range from selected IFRS financial information to full IFRS financial statements. Mr. Schnurr further noted that "[u]nder this line of thinking,

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

[2] In April 2012, the JOBS Act was signed into law to increase American job creation and economic growth by improving access to the public capital markets for emerging growth companies (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.

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

issuers that do not believe IFRS-based information would be beneficial to investors would not be forced to undertake what we understand to be, in some cases, significant implementation costs." The SEC is expected to solicit feedback on this approach in 2015. See Deloitte's December 15, 2014, *Heads Up* for additional information about the potential alternative.

Other SEC Matters

Financial Reporting Manual Updates

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

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

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

CAQ SEC Regulations Committee Meeting Highlights

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

PCAOB Auditing Standard 18 on Related Parties

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

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

PCAOB's Rules on Auditing Supplemental Information

On February 12, 2014, the SEC released an order approving PCAOB Auditing Standard 17 (issued in October 2013), which prescribes the auditor's responsibilities related to supplemental information accompanying a registrant's financial statements. Auditing Standard 17 is effective "for audit procedures and reports on supplemental information that accompanies financial statements for fiscal years ending on or after June 1, 2014."

Oil and Gas Company Observations

At the AICPA Conference on Current SEC and PCAOB Developments in December 2014, the staff in the SEC's Division of Corporation Finance reminded registrants in the O&G industry to consider the recent declines in O&G prices and the related potential impact on exploration and development activities.

Specifically, the staff highlighted that such changes may:

- Represent a known trend or uncertainty that should be discussed in a registrant's MD&A.
- Represent a risk that should be discussed in a registrant's risk factor disclosures.
- Affect the determination of estimated proved reserves.

The Division staff referred registrants to Regulation S-X, Rule 4-10(a), and Question 131.04 of the SEC's C&DI on the definition of proved undeveloped oil and gas reserves and the interaction of that definition with a registrant's development plan. The staff noted that the mere intent to develop reserves does not constitute adoption of a development plan, which would require a final investment decision. A registrant's scheduled drilling activity should reconcile to its investment plans that have been approved by management. See Deloitte's December 15, 2014, *Heads Up* for additional information. In addition, watch for Deloitte's upcoming *Oil & Gas Spotlight* for a discussion of the effects of declining oil and natural gas prices on entities operating in the O&G sector.

Cybersecurity

Cybersecurity Roundtable

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

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

Risk Alert

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

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

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

Communications to XBRL Filers

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

- *Sample Letter Sent to Public Companies Regarding XBRL Requirement to Include Calculation Relationships* — Reminds registrants that the XBRL rules "require that [registrants] include calculation relationships for certain contributing line item elements for [the] financial statements and related footnotes." Registrants are advised to "take the necessary steps to ensure that [they] are including all required calculation relationships" in their XBRL files.
- *Staff Observations of Custom Tag Rates* — Observations resulting from the staff's assessment of the quality of a sample of XBRL exhibits submitted from 2009 through October 2013. Although the staff noted a decline in large filers' use of custom XBRL tags during the review period, it did not observe a similar decline in usage by smaller filers.

See Deloitte's July 8, 2014, journal entry for more information.

SEC Staff Comments

Background

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

The SEC staff's comments to registrants in the O&G industry continue to focus on (1) master limited partnerships (MLPs); (2) oil and gas reserves; (3) disclosures about drilling activities, wells and acreage data, and delivery commitments; and (4) non-GAAP financial measures.

Master Limited Partnerships

Distributable Cash Flow

Examples of SEC Comments

- [You state] that Distributable Cash Flow provides investors with an approximation of Available Cash, as defined in your partnership agreement, prior to the establishment of any cash reserves. Please provide us with a comparison of the calculations of Available Cash and Distributable Cash Flow (e.g., tell us how capital expenditures are determined in calculating Available Cash). With your response, please tell us about the extent to which Distributable Cash Flow is considered by management and the board of directors in determining actual cash distributions. . . . As part of your response, explain how you evaluate, and how you believe investors should consider any excess or shortfall of Distributable Cash Flow over actual cash distributions for any given period.
- We note that a significant component of your distributable cash flow calculation is maintenance capital expenditures, which reduce the cash flow available for distribution to your unit holders. Since we understand that the definition of this term may vary within the industry, please tell us your definition of maintenance capital expenditures. Specifically, please clarify what you are maintaining: a specific level of net assets, throughput, capacity, profitability, etc. Since we understand that the definition of this term may vary, please also tell us how you considered clarifying this matter to your investors.

The partnership agreements of MLPs typically define distributable cash flow and often call for a distinction between capital expenditures associated with maintenance and those associated with growth. In turn, MLPs frequently disclose distributable cash flow and capital expenditure amounts. Consequently, because distributable cash flow is not determined on the basis of SEC rules or U.S. GAAP, SEC staff comments to industry registrants may focus on:

- Clarifying how distributable cash flow is calculated.
- Providing greater clarity about how distributable cash flow is calculated.
- How maintenance capital expenditures is defined and how it affects distributable cash flow.
- Describing the relationship between the calculated amount of distributable cash flow and actual distributions.
- Understanding liquidity ramifications related to requirements to distribute cash.
- Compliance with Regulation S-K, Item 10(e), with respect to non-GAAP financial measures, including (1) how distributable cash flow is used by management and (2) the registrant's reconciliation of the non-GAAP measure to the appropriate GAAP measure (e.g., why distributable cash flow as a cash measure is reconciled to a profit measure, such as net income, instead of to operating cash flows).

EPU Considerations

MLPs are common structures used in the energy and real estate industries. Frequently, MLPs have differing classes of ownership units, such as general partner (GP) units, limited partner (LP) units, and incentive distribution rights, that participate in earnings on the basis of the contractual rights stipulated in the partnership agreement; therefore, in such cases, MLPs must apply the two-class method in ASC 260 to determine EPU. MLPs also commonly engage in dropdown transactions, in which the GP of the MLP transfers assets to the MLP in exchange for a greater partnership interest in the MLP or cash (or both).

ASC 260 does not address how the MLP's presentation of historical EPU would be affected by a dropdown transaction that (1) occurs after the MLP's initial formation and (2) is accounted for as a reorganization of entities under common control. As a result, two common approaches have developed, as noted in a memorandum prepared for the EITF's deliberations on this issue at its September 2014 meeting:

- Restate historical EPU "by allocating the net income (loss) of the transferred business prior to the date of the dropdown transaction to the GP, LPs, and [other participating interest] holders."
- Allocate "the net income (loss) of the transferred business prior to the date of the dropdown transaction entirely to the GP." The memorandum indicates that "[u]nder this alternative, there is no retrospective adjustment to previously reported EPU."

Consequently, the SEC staff has asked registrants about the basis for their EPU calculations in dropdown transactions. To address the diversity in practice, the FASB issued a proposed ASU in October 2014 under which an MLP would perform the allocation by using the second approach described above. As a result, there would be no adjustment to historical EPU reported for LP units.

Oil and Gas Reserves

Proved Undeveloped Reserves

Example of an SEC Comment

You disclose that a significant percentage of your net undeveloped acreage will expire over the next three years. Please tell us the extent to which you have assigned any proved undeveloped reserves as of December 31, 2012 to locations which are currently scheduled to be drilled after lease expiration. If your undeveloped reserves include any such locations, please refer to Rule 4-10(a)(26) of Regulation S-X and tell us the steps you will take regarding an extension of your legal right to these leases; otherwise, please remove these undeveloped reserves as proved reserves in your next filing.

Under Regulation S-X, Rule 4-10(a)(22), a registrant should be reasonably certain when estimating proved reserves that the reserves can be recovered in future years under existing economic conditions. In accordance with Rule 4-10(a)(31)(ii), "[u]ndrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time."

The SEC staff may ask registrants to justify recorded proved undeveloped (PUD) reserves that will remain undeveloped for more than five years because a registrant's decision not to develop PUD reserves for such a long period may indicate uncertainty regarding development and ultimate recoverability. In accordance with Regulation S-K, Item 1203(d), a registrant may be asked to explain why the reserves have not been or will not be developed, why it believes that the reserves are still appropriate, and how it plans to develop the reserves within five years given the registrant's historical conversion rate. The SEC staff may also ask registrants to support engineering assumptions, such as terminal decline rates, used in proved reserve estimates, as well as assumptions used in future cash flow analyses (e.g., estimated future well costs).

Separate Disclosure of Natural Gas Liquids

Example of an SEC Comment

We note you disclose proved reserves of crude oil, condensate and natural gas liquids (NGLs) as a single aggregated quantity in the table. . . . The staff considers NGLs to be a separate product type under Item 1202(a)(4) of Regulation S-K; therefore, NGL reserves, if material, should be presented as separate quantities for disclosure under Item 1202(a)(2) of Regulation S-K. Please revise your disclosures to separately present, on a disaggregated basis, your NGL reserve quantities.

Although NGLs are not separately identified as a product type in Regulation S-K, Item 1202(a), they are discussed in ASC 932-235-50-4. Accordingly, the SEC staff may ask registrants to disclose NGLs separately if they aggregate significant NGLs with other product types in their disclosures of proved reserves.

Significant Changes in Reserves and Standardized Measures

Examples of SEC Comments

- Please revise your disclosure of proved reserve quantities to include an explanation of significant changes that occurred during the periods presented. Refer to FASB ASC 932-235-50-5.
- Please expand your disclosure of the changes in net quantities of proved reserves to include appropriate explanations of significant changes relating to extensions and discoveries, other additions and revisions of previous estimates, for each of the reporting periods shown, to comply with FASB ASC Topic 932-235-50-5.

The SEC staff has commented on registrants' disclosures about (1) changes in proved reserves and standardized measures and (2) their compliance with ASC 932-235-50. Accordingly, the SEC staff may ask registrants to (1) describe the technical factors (e.g., the activities, findings, and circumstances) that led to significant changes in proved reserves, (2) address negatively revised estimates attributable to performance separately from those attributable to price reductions, (3) explain significant changes in extensions and discoveries, and (4) disclose prices used in the calculation of standardized measures. Further, the SEC staff may (1) ask industry registrants whether abandoned assets have been included in the standardized measure and, if so, to provide information about them and (2) refer registrants to guidance in a sample letter provided by the Division of Corporation Finance.

Reserve Reports

Example of an SEC Comment

Please file a third party report that complies with the requirements of Item 1202(a)(8) of Regulation S-K: (i) The purpose for which the report was prepared and for whom it was prepared; (ii) The date on which the report was completed; (iv) The data and procedures used, including the percentage of the registrant's total reserves reviewed in connection with the preparation of the report, and; (x) The signature of the third party. Include the third party's responsible person's technical qualifications as required by Item 1202(a)(7) of Regulation S-K.

Under Regulation S-K, Item 1202(a)(8), a registrant must file a third-party report as an exhibit to its periodic report or registration statement when it "represents that a third party prepared, or conducted a reserves audit of, the registrant's reserves estimates, or any estimated valuation thereof, or conducted a process review." Accordingly, certain disclosures are required under Item 1202(a)(8). The SEC staff issues comments when these required disclosures are omitted. Often, the staff's comments are related to the requirement in Regulation S-K, Item 1202(a)(8)(iv), to disclose the "assumptions, data, methods, and procedures used, including the percentage of the registrant's total reserves reviewed in connection with the preparation of the report, and a statement that such assumptions, data, methods, and procedures are appropriate for the purpose served by the report."

Drilling Activities, Wells, Acreage, and Delivery Commitments

Examples of SEC Comments

- Please revise or otherwise expand your disclosure to present the total gross and net productive wells expressed separately for oil and gas as of a reasonable current date or as of the end of the current fiscal year pursuant to the disclosure requirements under Item 1208(a) of Regulation S-K.
- Please expand the disclosure of your present activities, such as the number of wells in the process of being drilled, completed or shut in awaiting infrastructure, to provide this information as of March 31, 2014. Please refer to the disclosure requirements in Item 1206 of Regulation S-K.

The SEC staff has continued to focus on registrants' disclosures about production information, drilling activities, wells and acreage data, and delivery commitments under Regulation S-K, Items 1204, 1205, 1206, 1207, and 1208. Additional disclosures that may be requested include (but are not limited to) the following:

- Production by geographic area and for each country and field that contains 15 percent or more of the registrant's total proved reserves.
- Drilling activities for each of the last three years by geographic area.
- Steps to be taken to meet significant delivery commitments.
- The number of wells that the registrant operates, including the total gross and net productive wells, expressed separately for oil and gas by geographic area.
- Information related to undeveloped acreage regarding minimum remaining terms of leases and concessions for material acreage concentrations, including significant undeveloped acreage that will be expiring over the next three years.

Non-GAAP Financial Measures

Registrants in the O&G industry commonly use derivative instruments to hedge their exposure to commodity price risk. However, registrants may elect not to apply hedge accounting to such derivative transactions. Accordingly, any mark-to-market adjustments would be recorded in registrants' earnings (i.e., unrealized gains and losses would be recorded in profit and loss in registrants' income statements). In addition, some registrants may present non-GAAP financial measures, such as adjusted EBITDA, as well as adjustments (in the required reconciliation to the most directly comparable GAAP measure) for the effects of such derivative transactions (e.g., excluding net unrealized gains/losses), which the SEC has indicated may not be in accordance with U.S. GAAP. As a result, the SEC staff has asked registrants to present two separate reconciling items within the non-GAAP reconciliation for (1) total net gains or losses in accordance with U.S. GAAP (i.e., total net realized and unrealized gains/losses) and (2) net cash receipts or payments for derivatives settled during the period (i.e., net realized gains/losses).

See Deloitte's *SEC Comment Letters — Including Industry Insights: A Recap of Recent Trends* for a more detailed discussion of trends identified in the SEC staff's comment letters, which includes those that apply to O&G registrants.

Section 4
Carve-Out Financial Statements

In response to various market factors, O&G entities may seek to dispose of a portion of their operations. Increasingly, such companies have sought to divest undervalued or strategically misaligned operations to unlock their value.

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

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

Internal Control Considerations

Internal control over financial reporting (ICFR) is one important item for O&G entities to consider when carving out a portion of their operations into a new entity. Key questions for entities to ask about ICFR include:

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

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

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

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

Judgments and Allocations

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

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

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

Tax Considerations

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

Reporting Considerations

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

Section 2065.11 of the FRM details the financial statement requirements for an "acquisition of an interest in a producing oil or natural gas property." The FRM notes that "[i]f the property acquired represents less than substantially all of the selling entity's key operating assets, the registrant should provide the carve-out financial statements." Section 2065.11 also highlights that the SEC staff will accept abbreviated financial statements (e.g., statements of revenues and direct expenses) in lieu of the full financial statements required under Regulation S-X, Rule 3-05, in certain specified circumstances. Registrants are no longer required to preclear their submission of abbreviated financial statements with the Office of the Chief Accountant in the Division of Corporation Finance.

Discontinued Operations

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

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

Business Segment Disclosure

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

Transactions Between Entities Under Common Control

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

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

SEC Reporting

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

Other Resources

For additional guidance on carve-out financial statements, see Deloitte's *A Roadmap to Accounting and Financial Reporting for Carve-Out Transactions*.

Section 5
Income Taxes

This section summarizes FASB 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.

Tax Extenders Bill Becomes Law

On December 19, 2014, President Obama signed into law the Tax Increase Prevention Act of 2014, which retroactively extends for one year the bulk of the temporary tax deductions, credits, and incentives that expired at the end of 2013. The act was approved on a bipartisan basis in the House of Representatives on December 3, 2014, and the Senate on December 16, 2014. Its passage and enactment mark the last significant action in the tax policy arena in the 113th Congress, which has now officially adjourned. (The 114th Congress convened on January 6, 2015.)

The tax relief in the extenders package is short-lived, since the retroactive renewal of more than 50 temporary provisions sunsets at year-end. For taxpayers who rely on these provisions for planning purposes, this means a return to uncertainty. For lawmakers, it means the debate over the future of these provisions begins anew in the 114th Congress.

In addition to addressing extenders, the new law includes permanent provisions that authorize the creation of tax-preferred savings accounts for use by certain individuals with disabilities and their caregivers to pay for certain qualified disability expenses.

Highlights of Extended Provisions

Among the dozens of expired provisions that were renewed through the end of 2014 under the extenders legislation are:

- The research and experimentation (R&E) credit.
- Bonus depreciation and the election to accelerate alternative minimum tax credits in lieu of additional first-year depreciation.
- Increased expensing limits ($500,000/$2 million) for Section 179 property and the expanded definition of such property.
- The Subpart F exception for active financing income.
- Look-through treatment of payments between related controlled foreign corporations under the foreign personal holding company rules.
- Fifteen-year straight-line cost recovery for qualified leasehold improvements, qualified restaurant buildings and improvements, and qualified retail improvements.
- The production tax credit for wind and other alternative forms of energy.
- The credit for alternative fuel vehicle refueling property.
- The deduction for energy-efficiency improvements to commercial buildings.
- The credit for construction of energy-efficient new homes.
- The deduction for energy-efficiency improvements to existing homes.
- The New Markets Tax Credit.
- The Work Opportunity Tax Credit.
- The reduced recognition period for S corporation built-in gains tax.
- The basis adjustment to stock of S corporations making charitable contributions of property.

- The deduction for charitable contributions of food inventory.
- Tax-free distributions from individual retirement plans by individuals aged 70½ and older for charitable purposes.
- Special rules for contributions of capital-gain real property made for conservation purposes.
- The deduction for state and local sales taxes.
- The income exclusion for employer-provided mass transit and parking benefits.

Under the approved legislation, none of the extenders provisions are modified from prior law.

Provisions Not Renewed

The bill would not renew a handful of provisions related to, among other things, expensing of certain refinery property, manufacturing of energy-efficient appliances, and health insurance tax credits for certain unemployed individuals.

Other Provisions Extended

In addition to addressing most of the expired 2013 extenders, the Tax Increase Prevention Act extends through 2015 two current-law provisions that were scheduled to sunset at the end of 2014 that (1) permit multiemployer defined benefit pension plans to take an additional five years to amortize funding shortfalls and (2) provide special rules allowing severely underfunded multiemployer plans to start or stop using the shortfall funding method without obtaining approval from the U.S. Department of the Treasury. (These provisions were originally enacted under the Pension Protection Act of 2006.)

Final Regulations on Dispositions of Depreciable Property and General Asset Accounts

On August 14, 2014, the U.S. Department of the Treasury and the IRS issued final regulations (T.D. 9689) addressing dispositions of property subject to depreciation under IRC Section 168 and amending the regulations for general asset accounts (GAA) and the accounting for Modified Accelerated Cost Recovery System property. The final regulations generally retain the provisions of the 2013 proposed regulations (REG-110732-13), with insignificant clarifications.

The final regulations are generally effective for taxable years beginning on or after January 1, 2014. For taxable years beginning on or after January 1, 2012, and before January 1, 2014, taxpayers may apply the final regulations, the 2013 proposed regulations, or the 2011 temporary regulations (T.D. 9564) or, alternatively, taxpayers may wait to comply with the final regulations until their first tax year beginning on or after January 1, 2014. The IRS's Rev. Proc. 2014-54 provides taxpayers with guidance on how to obtain automatic consent for method changes to comply with the final regulations.

Rev. Proc. 2014-54 modifies the procedures in Rev. Proc. 2014-17 regarding certain changes in the method of accounting for dispositions of tangible depreciable property and allows for a one-year extension of late partial disposition elections under IRC Section 168. Rev. Proc. 2014-54 also revises Rev. Proc. 2014-17 to indicate that IRC Section 280B does not apply to the demolition of a building in a GAA unless the taxpayer elects to terminate the GAA upon the disposition of all or the last asset in the GAA or makes a qualifying disposition election. Thus, a taxpayer may continue to depreciate the demolished building in a GAA rather than to capitalize the undepreciated cost of the building at demolition as additional basis in land as required by IRC Section 280B.

Research and Experimentation Expenditures

During 2014, the IRS issued final regulations (T.D. 9680) to amend the definition of R&E expenditures under IRC Section 174. The final regulations provide guidance on the treatment of amounts incurred in connection with the development of tangible property, particularly costs incurred to design and construct prototypes and pilot models that ultimately are placed in service by the taxpayer or sold to customers. The final regulations are similar to the proposed regulations issued in September 2013, providing much-needed clarity regarding the expenditures that are within the scope of IRC Section 174 and that (in some situations) may also qualify for the research credit allowed under IRC Section 41.

Notably, the final regulations expressly state (as did the proposed regulations) that "[t]he ultimate success, failure, sale, or use of the product is not relevant to a determination of eligibility under IRC Section 174." Along with this provision, the final regulations clarify that "pilot models" eligible for IRC Section 174 treatment include any representation or model of a product — even a "fully-functional" unit of property produced by the taxpayer or on its behalf — that is produced to evaluate and resolve uncertainty concerning the product during the product's development or improvement (meaning that production may have begun but design uncertainty has not yet been eliminated). The final regulations clarify that this concept may include multiple pilot models produced to test the appropriate design of a product in one or more different environments but does not require that each pilot model be tested for a purpose different from that of other pilot models. The final regulations contain 11 examples illustrating the various expenditures that may be deducted under IRC Section 174 when incurred to develop a new product for sale or use by the taxpayer (including a "variant product" with dimensions different from those of an existing commercial product) or to integrate a new or improved component into an existing product for which there otherwise is no design uncertainty regarding the product as a whole.

The final regulations are generally effective for taxable years ending on or after July 21, 2014. However, Treas. Reg. Section 1.174-2(d) indicates that taxpayers may apply the provisions of the final regulations to taxable years for which the limitations for assessment of tax have not expired. Consequently, the pro-taxpayer clarifications may be used to address issues currently raised by IRS examiners, as well as to take positions on taxable year 2013 returns, amend prior open-year returns, and possibly modify carryforward schedules to reflect increased net operating losses (NOLs) or credit amounts from closed taxable years.

Federal Update on Safe Harbor Election for Success-Based Fees Paid to Professionals Other Than Investment Bankers

Rev. Proc. 2011-29 allows taxpayers to make a safe harbor election for years ending after April 8, 2011, to treat 70 percent of success-based fees paid in connection with a covered transaction, as defined in Treas. Reg. Section 1.263(a)-5(e), as "an amount that does not facilitate the transaction" for purposes of capitalization under Section 263(a). In 2013, the Large Business and International (LB&I) Division issued a directive (LB&I-04-0413-002) stating that LB&I auditors would not challenge a taxpayer's safe harbor treatment of its milestone payments for investment banking services made in the course of certain acquisitions that are creditable against a success-based fee. The LB&I Division issued a revised directive (LB&I-04-0114-001) on January 27, 2014.[1] The revised directive amends the definition of a "milestone" with respect to application of the safe harbor provision in Rev. Proc. 2011-29 to nonrefundable payments contingent on the achievement of a milestone ("milestone payments"). Under the revised directive, the term "milestone" has been significantly broadened and now includes an event, such as the passage of time, occurring in the course of a covered transaction — regardless of whether the transaction is ultimately completed. As previously noted in Chief Counsel Advice (CCA) 201234027, the National Office of the IRS, does not agree with the indication in the directives that nonrefundable milestone payments qualify as success-based fees.

On May 29, 2014, the Special Counsel to the Office of Associate Chief Counsel (Income Tax and Accounting) at the IRS clarified at a Federal Bar Association insurance tax seminar that taxpayers may include success-based fees paid to professionals other than investment bankers when making a safe harbor election under Rev. Proc. 2011-29 for allocating such fees when they are paid in business acquisitions or reorganizations. The clarification was made in response to confusion, created as a result of the above directives, regarding whether the safe harbor applied to service providers other than investment bankers.

[1] The directives are not an official pronouncement of law and cannot be used, cited, or relied on as such.

New Mexico Net Operating Losses

On March 10, 2014, New Mexico Governor Susana Martínez signed into law Senate Bill 106, which allows corporate taxpayers that generate NOLs for tax years beginning on or after January 1, 2013, to carry the loss forward twenty years. The carryforward period for losses generated before January 1, 2013, will continue to be five years.

Texas Court Ruling That Net Losses Are Included in Apportionment Factor Denominator

On November 13, 2014, the court of appeals for the 13th District of Texas upheld an assessment against a taxpayer, holding that gains were required to be offset against losses from the sale of investments and capital assets in the determination of the franchise tax apportionment factor denominator.[2] The case involved the application of Texas Tax Code Section 171.105(b), which states the following regarding the determination of the denominator of the franchise tax apportionment factor: "If a taxable entity sells an investment or capital asset, the taxable entity's gross receipts from its entire business for taxable margin *include only the net gain from the sale*" (emphasis added). The taxpayer argued that the proper interpretation of this statute was that gains only are included and that losses are therefore disregarded. The court of appeals disagreed, siding with the Texas Comptroller and concluding that gains are to be offset by losses from the sale of investments and capital assets.

Texas Court Ruling on Deductions Related to Cost of Goods Sold

On December 31, 2013, The Texas Third Court of Appeals held that, in calculating the Texas Franchise Tax, a taxpayer may deduct as costs of goods sold (COGS) certain costs related to real property services. Further, on January 16, 2014, the Texas Comptroller filed a motion for rehearing in the court of appeals, stating that it "accepts the Court's opinion and reasoning, but moves for rehearing to request . . . [clarification of] two areas of the opinion." Taxpayers that have excluded costs otherwise eligible for the COGS deduction on the basis that the costs were incurred by an affiliate that only provided services may wish to reconsider such treatment and whether a refund claim may be appropriate. The statute of limitations for refunds involving franchise tax reports filed in 2010 may expire as early as May 15, 2014. For additional details on the Texas Court of Appeals case, see Deloitte's *Texas Multistate Tax Alert*.

Presenting an Unrecognized Tax Benefit When Tax Carryforwards Exist

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

[2] *Hallmark Mktg. Co. v. Combs*, No. 13-14-00093-CV. For the procedural status of the case, see http://www.search.txcourts.gov/Case.aspx?cn=13-14-00093-CV&coa=coa13.

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

- An NOL carryforward, a similar tax loss, or a tax credit carryforward is not available as of the reporting date under the governing tax law to settle taxes that would result from the disallowance of the tax position.
- The entity does not intend to use the DTA for this purpose (provided that the tax law permits a choice).

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

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

Appendixes

Appendix A — Abbreviations

Abbreviation	Description
AFS	available for sale
AICPA	American Institute of Certified Public Accountants
AOCI	accumulated other comprehensive income
ASC	FASB Accounting Standards Codification
B&E	blend and extend
C&DI	SEC Compliance and Disclosure Interpretation
CECL	current expected credit loss
CMR	conflict materials report
COGS	cost of goods sold
DRC	Democratic Republic of the Congo
DSE	development-stage entity
DTA	deferred tax asset
ED	exposure draft
EITF	Emerging Issues Task Force
EPU	earnings per unit
FASB	Financial Accounting Standards Board
FRM	SEC's Division of Corporation Finance Financial Reporting Manual
FVTNI	fair value through net income
FVTOCI	fair value through other comprehensive income
GAA	general asset accounts
GAAP	generally accepted accounting principles
GP	general partner
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	international private-sector audit
IRC	Internal Revenue Code
IRS	Internal Revenue Service
LB&I	IRS Large Business and International Division
LP	limited partner
MD&A	Management's Discussion and Analysis
MLP	master limited partnership
MMBtu	million Btu
MMF	money market fund

Abbreviation	Description
NAV	net asset value
NGL	natural gas liquid
NOL	net operating loss
NYMEX	New York Mercantile Exchange
O&G	oil and gas
OCI	other comprehensive income
PBE	public business entity
PCAOB	Public Company Accounting Oversight Board
PCC	FASB's Private Company Council
PUD	proved undeveloped
R&E	research and experimentation
Rev. Proc.	IRS Revenue Procedure
ROU	right of use
SAB	SEC Staff Accounting Bulletin
SEC	Securities and Exchange Commission
TRG	transition resource group
UTB	unrecognized tax benefit
VIE	variable interest entity
VPP	volumetric production payment
XBRL	eXtensible Business Reporting Language

The following is a list of short references for the Acts mentioned in this publication:

Abbreviation	Act
Dodd-Frank Act	Dodd-Frank Wall Street Reform and Consumer Protection Act
Exchange Act	Securities Exchange Act of 1934
JOBS Act	Jumpstart Our Business Startups Act
Securities Act	Securities Act of 1933
Tax Increase Prevention Act	Tax Increase Prevention Act of 2014
Trust Indenture Act	Trust Indenture Act of 1939

Appendix B — Titles of Standards and Other Literature

The titles of the standards and other literature referred to in this publication are available from the sources below.

FASB Literature

For titles of *FASB Accounting Standards Codification* references, see Deloitte's "Titles of Topics and Subtopics in the *FASB Accounting Standards Codification*."

See the FASB's Web site for titles of:

- Accounting Standards Updates.
- Exposure documents open for comment.
- Exposure documents issued for public comment (archive).
- Pre-Codification literature (Statements, Staff Positions, EITF Issues, and Topics).
- Concepts Statements.

International Standards

See Deloitte's IAS*Plus* Web site for titles of:

- International Financial Reporting Standards (IFRSs).
- International Accounting Standards (IASs).

PCAOB Literature

- Auditing Standard 11, *Consideration of Materiality in Planning and Performing an Audit*
- Auditing Standard 17, *Auditing Supplemental Information Accompanying Audited Financial Statements*
- Auditing Standard 18, *Related Parties, Amendments to Certain PCAOB Auditing Standards Regarding Significant Unusual Transactions, and Other Amendments to PCAOB Auditing*
- AU Section 341, *The Auditor's Consideration of an Entity's Ability to Continue as a Going Concern*

SEC Literature

- Final Rules, Interim Final Rules, Proposed Rules, and Interpretive Releases:
    - Final Rule No. 33-9616, *Money Market Fund Reform; Amendments to Form PF*
    - Final Rule No. 33-9638, *Asset-Backed Securities Disclosure and Registration*
    - Final Rule No. 34-67716, *Conflict Minerals*
    - Final Rule No. 34-72472, *Interpretation, Application of "Security-Based Swap Dealer" and "Major Security-Based Swap Participant" Definitions to Cross-Border Security-Based Swap Activities*
    - Interim Final Rule No. 33-9545, *Extension, Extension of Exemptions for Security-Based Swaps*
    - Proposed Rule, No. 33-9497, *Proposed Rule Amendments for Small and Additional Issues Exemptions Under Section 3(b) of the Securities Act*

- Proposed Rule No. 34-71958, *Recordkeeping and Reporting Requirements for Security-Based Swap Dealers, Major Security-Based Swap Participants, and Broker-Dealers; Capital Rule for Certain Security-Based Swap Dealers*

- Forms:
  - Form 8-K, "Current Reports": Item 4.01, "Changes in Registrant's Certifying Accountant"
  - Form 10-K, "General Form of Annual Report"
  - Form 10-Q, "Quarterly Report Pursuant to Sections 13 or 15(d)" of the Exchange Act
  - Form SD, "Specialized Disclosure Report"
- Regulation A, "Conditional Small Issues Exemption"
- Regulation G, "General Rules Regarding Disclosure of Non-GAAP Financial Measures"
- Regulation S-K:
  - Item 10(e), "General: Use of Non-GAAP Financial Measures in Commission Filings"
  - Item 301, "Selected Financial Data
  - Item 1100, "Asset-Backed Securities (Regulation AB)"
  - Subpart 1200, "Disclosure by Registrants Engaged in Oil and Gas Producing Activities"
    - Item 1202, "Disclosure of Reserves"
    - Item 1203, "Proved undeveloped reserves"
    - Item 1204, "Oil and Gas Production, Production Prices and Production Costs"
    - Item 1205, "Drilling and Other Exploratory and Development Activities"
    - Item 1206, "Present Activities"
    - Item 1207, "Delivery Commitments"
    - Item 1208, "Oil and Gas Properties, Wells, Operations, and Acreage"
- Regulation S-X:
  - Rule 3-05, "Financial Statements of Businesses Acquired or to Be Acquired"
  - Rule 3-14, "Special Instructions for Real Estate Operations to Be Acquired"
  - Rule 4-10(a), "Financial Accounting and Reporting for Oil and Gas Producing Activities Pursuant to the Federal Securities Laws and the Energy Policy and Conservation Act of 1975: Definitions"
- SEC Staff Accounting Bulletins:
  - Topic 1.M (SAB 99), "Materiality"
  - Topic 5.J, "New Basis of Accounting Required in Certain Circumstances" (Removed by SAB 115)
  - Topic 13, "Revenue Recognition"

- Division of Corporation Finance, Financial Reporting Manual:
  - Topic 2, "Other Financial Statements Required"
  - Topic 9, "Management's Discussion and Analysis of Financial Position and Results of Operations (MD&A)"
- Securities Exchange Act of 1934 Rules:
  - Rule 12a-11, "Exemption of Security-Based Swaps Sold in Reliance on Securities Act of 1933 Rule 240 (§ 230.240) From Section 12(A) of the Act"
  - Rule 12h-1, "Exemptions From Registration Under Section 12(g) of the Act"
- Trust Indenture Act of 1939 Rules:
  - Rule 4d-12, "Exemption for Security-Based Swaps Offered and Sold in Reliance on Securities Act of 1933 Rule 240"

Appendix C — Deloitte Specialists, Acknowledgments, and Publications

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Deloitte Publications

For additional information about developments of interest to O&G companies, see the following issues of Deloitte publications:

- October 2014 *Oil & Gas Spotlight*, *"Fueling Discussion About the FASB's New Revenue Recognition Standard."*
- January 2014 *Oil & Gas Spotlight*, *"Impairment and Valuation Considerations Related to Oil and Gas Assets."*

Appendix D — Other Resources and Upcoming Events

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Events

WCEE Woman of the Year Gala — Washington, DC
March 3, 2015
For more information, please contact: Soylee1@deloitte.com.

Infocast Solar Summit — San Diego, CA
March 23–25, 2015
For more information, please contact: Mikcarlton@deloitte.com.

Mergermarket Energy M&A Forum — Houston, TX
April 14, 2015
For more information, please contact: Bridobrien@deloitte.com.

National Publicly Traded Partnership Conference
Summer/Fall 2015
For more information, please contact: amersinger@deloitte.com.

Alternative Energy Seminar — Dallas, TX
Fall 2015
For more information, please contact: AlternativeEnergy@deloitte.com.

Deloitte Oil & Gas Conference
Fall 2015
For more information, please contact: OilandGasConference@deloitte.com.

Deloitte Energy Accounting, Financial Reporting and Tax Update — Chicago, IL
December 2015
For more information, please contact: USEnergyFallSeminars@deloitte.com.

Deloitte Energy Transacting Accounting — Chicago, IL
December 2014
For more information, please contact: USEnergyFallSeminars@deloitte.com.

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