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Utilities and power companies

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About the Utilities and power companies guide

PwC is pleased to offer this *Utilities and power companies* guide. This guide was fully updated in March 2016. Since then, certain sections have been updated to reflect new guidance or interpretations. See Appendix D, *Summary of significant changes*, for more information.

We have organized this guide by topical area into 20 chapters. The chapters address a variety of accounting issues relevant for utilities and power companies and should be used as a supplement to US GAAP and to the general accounting guidance provided by other PwC guides. The chapters include accounting and financial reporting considerations in the following areas:

- Commodity contract accounting, including leasing and derivatives. Chapters relating to natural gas, emission allowances, and renewable energy credits are also included.
- Accounting for power-related investments including business combinations, investments in power plant entities, and consolidation of variable interest entities.
- Accounting for nonfinancial assets and liabilities including inventory, property, plant, and equipment, asset retirement obligations, and nuclear power plants. The accounting for government grants is also included.
- Accounting for regulated operations, including considerations relating to utility plant, income taxes, and business combinations.

Each chapter discusses the relevant accounting literature and includes specific questions and examples to illustrate application.

Locating guidance on particular topics

Guidance on particular topics can be located as follows:

- Table of contents—The table of contents provides a detailed listing of the various sections in each chapter. The titles of each section are intentionally descriptive to enable users to easily find a particular topic.
- Table of questions—The table of questions includes a listing of questions and PwC responses in numerical order, by chapter.
- Table of examples—The table of examples includes a listing of examples in numerical order, by chapter.

The guide also includes a detailed index of key topics.

References to US GAAP and International Financial Reporting Standards

Definitions, full paragraphs, and excerpts from the Financial Accounting Standards Board's *Accounting Standards Codification* and standards issued by the International Accounting Standards Board are clearly designated, either within quotes in the regular text or enclosed within a shaded box. In some instances, guidance was cited with minor editorial modification to flow in the context of the PwC Guide. The remaining text is PwC's original content.

References to other chapters and sections in this guide

Where relevant, the discussion includes general and specific references to other chapters of the guide that provide additional information. References to another chapter or particular section within a chapter are indicated by the abbreviation "UP" followed by the specific section number (e.g., UP 2.3.2 refers to section 2.3.2 in chapter 2 of this guide).

References to other PwC guidance

This guide focuses on the accounting and financial reporting considerations for utilities and power companies. It supplements information provided by the authoritative accounting literature and other PwC guidance. This guide provides general and specific references to chapters in other PwC guides to assist users in finding other relevant information. References to other guides are indicated by the applicable guide abbreviation followed by the specific section number. The other PwC guides referred to in this guide, including their abbreviations, are:

- *Business combinations and noncontrolling interests (BCG)*
- *Consolidation and equity method of accounting (CG)*
- *Derivative instruments and hedging activities (DH)*
- *Fair value measurements (FV)*
- *Financial statement presentation (FSP)*
- *Financing transactions: debt, equity and the instruments in between (FG)*
- *Foreign currency (FG)*
- *Leases (LG)*
- *Income taxes (TX)*
- *Revenue from contracts with customers (RR)*
- *Stock-based compensation (SC)*
- *Transfers and servicing of financial assets (TS)*

In addition, PwC's *Accounting and reporting manual* (the ARM) provides information about various accounting matters in US GAAP.

PwC guides may be obtained through CFOdirect (www.cfodirect.com), PwC's comprehensive online resource for financial executives, a subscription to Inform (www.pwcinform.com), PwC's online accounting and financial reporting reference tool, or by contacting a PwC representative.

Guidance date

This guide considers existing guidance as of March 31, 2016. Since then, section 20.4 has been updated to reflect new interpretations. See Appendix D, *Summary of significant changes*, for more information. Additional updates may be made to keep pace with significant developments. Users should ensure they are using the most recent edition available on CFOdirect (www.cfodirect.com) or Inform (www.pwcinform.com).

Other information

The appendices to this guide include a listing of technical references and abbreviations and a summary of significant changes from the previous edition.

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This guide has been prepared to support you as you consider the accounting for transactions and address the accounting, financial reporting, and related regulatory relevant to the industry. It should be used in combination with a thorough analysis of the relevant facts and circumstances, review of the authoritative accounting literature, and appropriate professional and technical advice.

We hope you find the information and insights in this guide useful.

Paul Kepple
US Chief Accountant

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***Chapter 1:
Commodity contract
accounting framework***

1.1 Chapter overview

The execution of commodity contracts is an integral business function for utilities and power companies as they seek to optimize revenue, manage costs, and procure supply necessary for the production or delivery of power and natural gas. Common commodity contracts include:

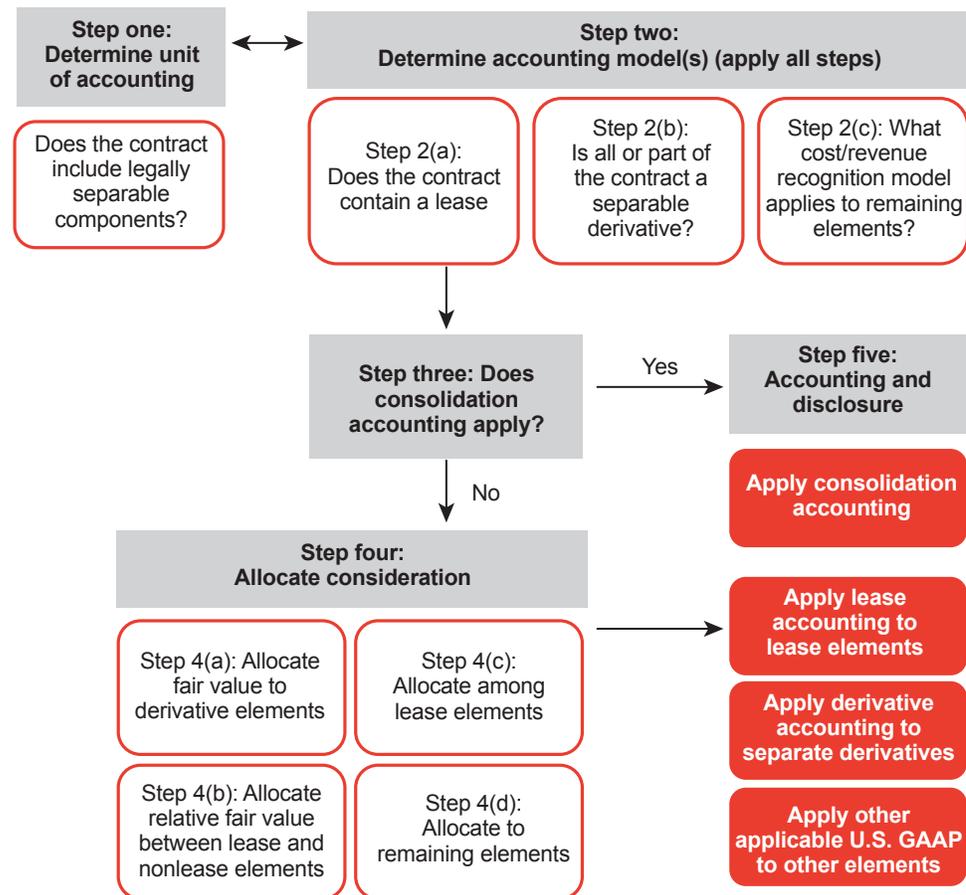
- Power purchase agreements
- Tolling arrangements
- Natural gas or other fuel supply agreements
- Contracts for the purchase or sale of emission allowances
- Contracts for the purchase or sale of renewable energy credits

The markets for energy and energy-related products continue to evolve, resulting in new products and contracts containing multiple elements (referred to interchangeably herein as elements, deliverables, or components) that sometimes complicate the accounting. This chapter provides a framework for evaluating the accounting for commodity contracts.

1.2 Contract framework

The accounting for commodity contracts brings together a breadth of accounting standards—leases, derivatives, revenue recognition, and consolidation—which are individually among the most complicated areas of accounting. Add their interaction, and it is understandable that commodity contract accounting is one of the most difficult areas of accounting for utilities and power companies. Figure 1-1 outlines a recommended framework for evaluating commodity contracts:

Figure 1-1
Recommended framework for accounting for commodity contracts



This general framework for the evaluation of commodity contracts provides an overall approach to performing the analysis. Reporting entities should apply the framework and consider all applicable guidance, even though the accounting for a particular contract may appear to be straightforward. For example, even a short-term power purchase agreement may include components that require application of different accounting models if (1) more than one product is being delivered under the contract, (2) the contract includes unique pricing elements, and/or (3) the contract meets the definition of a lease. Further, because of the complex interaction of the relevant guidance, the order of the analysis is a central component of accounting for commodity contracts.

1.2.1 **Step one: Determine the unit of accounting**

The first step in evaluating the appropriate accounting for a commodity contract is to determine the unit of accounting. The unit of accounting will depend on the nature of the agreements and may be impacted by the accounting model applied to elements of the contract, as established in Step two of the commodity contract framework.

The guidance generally applicable to commodity contracts includes lease and derivative accounting, as well as specialized industry guidance¹ and general guidance for executory contracts. When a contract contains multiple deliverables, these accounting models require consideration of whether there are any legally separable components (i.e., freestanding elements) that should be evaluated as separate units of accounting. In addition, in some cases, multiple agreements executed at the same time and in contemplation of each other may need to be accounted for as one contract (one unit of accounting) with multiple deliverables. Considerations in evaluating the unit of accounting include:

□ *Freestanding elements*

Features that are written in the same contract, but that may be legally detached and separately exercised would be considered freestanding instruments that should be accounted for separately — not subject to analysis in the context of the other deliverables under the contract. In such cases, once that element is separated, the remaining elements and deliverables would be evaluated in the context of the whole contract. For information on evaluating whether an element is freestanding or embedded, see UP 3.4, DH 3.1.1.1, and FG 7.3.

□ *Multiple agreements entered into at the same time—when lease model is applicable*

ASC 840, *Leases*, provides specific guidance for multiple agreements executed at the same time. ASC 840-10-15-16 indicates that the determination of whether a contract contains a lease should be based on the totality of the arrangement with the third party.

Excerpt from ASC 840-10-15-16

... separate contracts with the same entity or [its] related parties that are entered into at or near the same time . . . [should] be evaluated as a single arrangement in considering whether there are one or more units of accounting, including a lease.

□ *Multiple agreements in contemplation of one another—when derivative model is applicable*

ASC 815, *Derivatives and Hedging* (ASC 815), also discusses the accounting for multiple contracts executed at the same time. In general, ASC 815 does not require the combination of two freestanding derivatives to be viewed as one unit of accounting, unless the derivative instruments are jointly designated in a hedging relationship.

However, ASC 815-10-25-6 requires reporting entities to apply judgment to determine if separate derivatives have been executed in lieu of a structured

¹ Guidance originally issued as Emerging Issues Task Force (EITF) Issue No. 91-6, *Revenue Recognition of Long-Term Power Sales Contracts*, and EITF Issue No. 96-17, *Revenue Recognition under Long-Term Power Sales Contracts That Contain both Fixed and Variable Pricing Terms*, has been primarily codified as ASC 980-605-25-5 through 25-15 and ASC 980-605-25-17 and 25-18, respectively.

transaction. The characteristics to consider in making this assessment are: (1) the transactions are entered into contemporaneously and in contemplation of one another; (2) they are entered into with the same counterparty; (3) they relate to the same risk; and (4) there is no substantive business purpose for structuring the transactions separately. If it is determined these characteristics are not present, the freestanding derivative instruments would be viewed as separate units of accounting.

Once the unit of accounting is determined, the reporting entity should apply the evaluation hierarchy applicable under U.S. GAAP, as further discussed in Step two. For purposes of this discussion, we have referred to the unit of accounting as the contract; however, as noted, the unit of accounting could be part of a contract or multiple contracts combined.

1.2.2 Step two: Determine the accounting model(s) for the contract elements

The U.S. GAAP hierarchy establishes when and in what order reporting entities should apply the accounting guidance in evaluating a commodity contract. In particular, the order of applying the hierarchy of guidance may significantly alter the accounting conclusions reached when evaluating a contract that includes more than one deliverable. The FASB has specifically addressed the scope of the guidance and clarified the order of application for multiple deliverable contracts within ASC 605, *Revenue Recognition*.

ASC 605-25 addresses the interaction of the revenue recognition guidance and the application of the multiple-elements approach when a contract includes leases or elements that are in the scope of other ASC topics. In accordance with ASC 605-25-15-3A(a), deliverables in a multiple-element arrangement that are within the scope of another area of U.S. GAAP should follow the other separation and allocation guidance, as applicable.

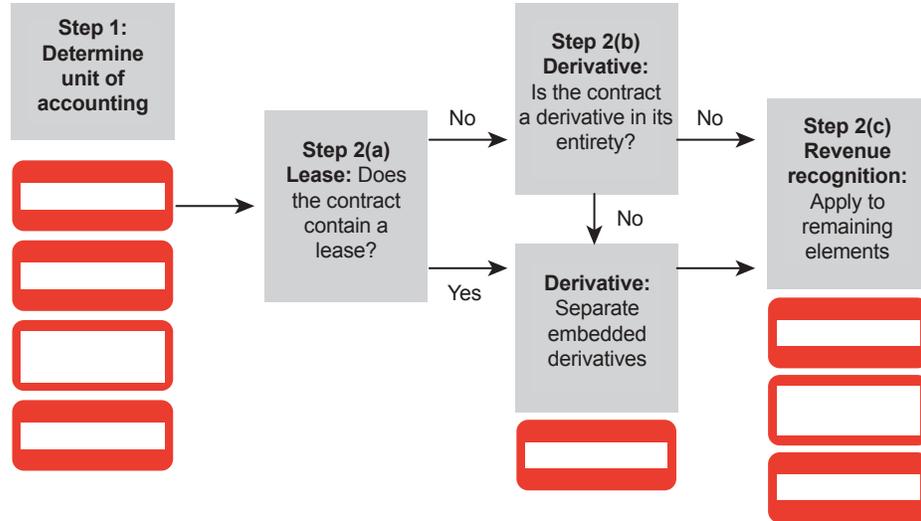
When evaluating a multiple deliverable contract, the reporting entity should initially evaluate each element separately to determine the applicability of the lease and derivative accounting models. In applying the contract hierarchy, it would account for any lease or derivative elements as separate units of accounting if they meet the hybrid bifurcation criteria (in the case of derivatives). See UP 3.4 for further information on evaluating embedded derivatives.

New guidance

ASC 606, *Revenue from Contracts with Customers*, includes new guidance on revenue recognition that is effective for public companies filing U.S. GAAP financial statements in the first interim period within annual reporting periods beginning on or after December 15, 2016. Preparers and other users of this publication should consider whether the new guidance will change any conclusions reached under current U.S. GAAP.

Figure 1-2 depicts the evaluation hierarchy.

Figure 1-2
Hierarchy for application of U.S. GAAP to a sample compound commodity contract



For purposes of illustrating the hierarchy, this example assumes that the contract does not contain a lease, and is not a derivative in its entirety. It assumes that derivative accounting is applicable to the energy component, but not to the capacity, ancillary services, and renewable energy credits (RECs) within the agreement. In addition, unless the contract is a derivative in its entirety, it should be evaluated for any embedded derivatives potentially requiring separation from the host contract. The illustration is intended to depict application of the U.S. GAAP hierarchy to an example contract.

As illustrated in Figure 1-2, in accounting for a contract with multiple deliverables, a reporting entity should first determine whether the contract contains a lease. If the contract does not contain a lease, the reporting entity should next assess whether it is a derivative in its entirety. Unless the contract is a derivative in its entirety, a reporting entity should then consider whether the contract contains any embedded derivatives requiring separation from the host contract. Both parties to the contract would then apply an executory contract accounting model to any remaining elements. The evaluation hierarchy is further discussed in the following sections.

1.2.2.1 Step 2(a): Determine whether the contract is or contains a lease

In determining the unit of accounting, a commodity contract should be evaluated to determine whether the contract contains a lease. It should perform the lease assessment prior to the application of any other potentially applicable U.S. GAAP. Lease accounting under ASC 840 would apply if the contract explicitly or implicitly identifies specified property, plant, or equipment.

See UP 2 for further information on determining whether a contract contains a lease.

Question 1-1

Why is lease accounting considered first when determining the accounting model(s) to apply to a commodity contract?

PwC response

The lease assessment is performed before evaluating application of the derivative guidance in accordance with ASC 815-10-15-79, which provides a scope exception for leases.

ASC 815-10-15-79

Leases that are within the scope of Topic 840 are not derivative instruments subject to this Subtopic, although a derivative instrument embedded in a lease may be subject to the requirements of paragraph 815-15-25-1.

There are some contracts that contain a lease under ASC 840 that include a derivative or embedded derivative and would be subjected to derivative accounting if it was considered first. Therefore, the order of application of the guidance may have a significant impact on accounting and disclosure.

1.2.2.2 Step 2(b): Determine whether the contract is or contains a derivative

If the contract does not contain a lease, the reporting entity should next assess whether it is a derivative in its entirety or whether it contains any embedded derivatives requiring separation from the host contract.

A compound contract may potentially include more than one element that would be a derivative on a stand-alone basis (e.g., both energy and natural gas) along with nonderivatives (e.g., renewable energy credits). ASC 815 provides guidance on the evaluation of compound contracts. Specifically, ASC 815-15-25-7 and 25-8 address compound embedded derivatives in a hybrid contract and require that they be bundled together as a single, compound embedded derivative to be accounted for separately from the host contract, instead of being separated as components representing separate risks. The evaluation of hybrid instruments and the determination of whether embedded derivatives should be separated from the host contract will be an ongoing area of focus as contracts and markets continue to evolve. See UP 3 for information on evaluating derivatives and embedded derivatives in commodity contracts.

1.2.2.3 Step 2(c): Determine whether executory contract accounting applies

Once a reporting entity has identified any lease or derivative components that require separate accounting, it should apply executory contract accounting for any remaining contract elements. ASC 980, *Regulated Operations* (ASC 980), provides guidance for accounting for regulated entities and specialized literature for all entities to consider in accounting for power purchase agreements that are not leases or derivatives (ASC 980-605-25). In addition, reporting entities may need to consider revenue recognition

guidance for contractual elements such as renewable energy credits (see UP 7). Accrual accounting should be applied to any remaining elements of the contract.

1.2.3 Step three: Determine whether consolidation accounting applies

If one of the parties to a commodity contract is a variable interest entity (VIE), ASC 810, *Consolidation*, may apply, regardless of the accounting model(s) applied to the contract or its components. In addition, the accounting model(s) applied to the commodity contract may impact the evaluation and conclusions reached under VIE accounting. For example, there are different considerations in assessing the design of a VIE, depending on whether the power purchase agreement contains a lease, a derivative, or is accounted for as an executory contract. As a result, the determination of the appropriate accounting model(s) for the contract is performed prior to applying the consolidation guidance.

New guidance

In February 2015, the FASB issued ASU 2015-02, *Consolidation—Amendments to the Consolidation Analysis*. The standard is effective for public reporting entities in fiscal periods beginning after December 15, 2015, and fiscal periods beginning after December 15, 2016 for nonpublic business entities. Early adoption is permitted. See UP 10 for information on evaluating whether a single power plant entity should be consolidated under both the current and amended guidance.

1.2.4 Step four: Determine allocation of consideration

The way that contract consideration is allocated over the term of the contract may be complex due to the interaction of the lease, derivative, and revenue recognition guidance. Similar to other aspects of the commodity contract framework, the determination may be straightforward for a simple contract with only one deliverable, but may be more complex if the contract contains more than one element.

A reporting entity should allocate contract consideration after it determines the accounting model applied to each component or element of the contract. The hierarchy for allocating consideration differs from that used to determine the appropriate accounting model. Consideration should be allocated first to any derivative elements (in contrast, lease accounting is assessed first in the determination of the appropriate accounting model).

Figure 1-3 summarizes key guidance to consider in determining the appropriate allocation of revenue and costs among contract components once the unit of accounting has been established.

Figure 1-3
Allocation of contract consideration

Element	Allocation considerations
4(a) Allocate fair value to derivative elements	<ul style="list-style-type: none"> □ Contract is a derivative in its entirety—A contract that is a derivative in its entirety should be recorded at fair value (unless the normal purchases and normal sales scope exception is applied, in which case the contract follows an executory contract model). □ Contract includes an embedded derivative—ASC 815-15-30-2 requires reporting entities to record an embedded derivative separated from its host contract at fair value at inception (i.e., generally at zero on day one for non-option based derivatives and at fair value for options, resulting in no “day one” gain or loss); the remaining value is assigned to the host contract. □ Contract contains multiple embedded derivatives—If the contract contains multiple embedded derivatives, they should be accounted for as one element (i.e., a compound derivative). See UP 3.4 for further information.
4(b) Allocate relative fair value between lease and nonlease elements (excluding derivatives)	<ul style="list-style-type: none"> □ Overall allocation—In accordance with ASC 840-10-15-19, total consideration should be allocated between lease elements (lease of property and related executory costs) and nonlease elements (other products and services, excluding any derivatives), based on relative fair value in accordance with ASC 605-25-15-13A(b). □ Methods of allocation—There are three acceptable methods of allocating between lease and nonlease elements: (1) variable expected volume method; (2) fixed expected volume method; and (3) minimum volume method. See ARM 4650.161 for information. □ Nonlease elements—The allocation of consideration among the nonlease elements should follow the guidance for derivatives or multiple-element arrangements as applicable.
4(c) Allocate among lease elements	<ul style="list-style-type: none"> □ Lease payments should first be allocated to executory costs, including profit thereon. □ The amount remaining is assigned to lease payments, assuming there are no contingent rentals.
4(d) Allocate to remaining elements	<ul style="list-style-type: none"> □ Guidance for multiple-element arrangements (ASC 605-25) should be applied by both buyers and sellers to allocate contract consideration to any nonderivative, nonlease elements.

1.2.5 Step five: Accounting and disclosure

Individual topics associated with application of the commodity contract framework are further addressed in specific chapters within this Guide. Refer to the relevant chapters for further information.

Chapter 2:

Leases

2.1 Chapter overview

Utilities and power companies enter into a variety of arrangements that may be in the form of or contain a lease (e.g., power purchase agreements, third-party contracts to construct generation facilities, right-of-way agreements). In determining the appropriate accounting for a contractual arrangement to purchase or supply goods or services, reporting entities should first consider whether the arrangement contains a lease. See UP 1 for further information on the overall contract evaluation framework.

The analysis as to whether an arrangement contains a lease and, if so, the determination of the appropriate lease classification, may require considerable judgment. This chapter provides guidance on evaluating power purchase agreements to determine whether they contain a lease. It also addresses other leasing issues applicable to leases of power plants, including the allocation of contract consideration, lease classification, and presentation and disclosure. Similar consideration with regard to the existence of a lease would also apply to other arrangements common in the utility and power industry, such as transmission agreements, natural gas storage contracts, and transportation agreements. This chapter focuses on power purchase agreements due to their prevalence in the industry.

Utilities and power companies that transact with a governmental body, or an entity to which the responsibility for the public service has been delegated, should consider the guidance in ASC 853, *Service Concession Arrangements* to determine whether an arrangement involving infrastructure is within the scope of lease accounting.

This chapter supplements PwC's *Accounting and Reporting Manual 4650* and does not address all aspects of the authoritative lease guidance contained in ASC 840. Rather, it focuses on leasing issues unique to utilities and power companies. See UP 18.9 for information on lease accounting issues specific to regulated utilities.

Note about ongoing standard setting

The FASB issued ASC 842, *Leases*, in February 2016, which amends the guidance discussed in this chapter. The amended guidance will be effective for public companies for annual reporting periods beginning after December 15, 2018. Non-public companies have an additional year.

2.2 Determining whether a power purchase agreement contains a lease

A lease provides the right to use land or other property, plant, or equipment that is the subject of the lease or other arrangement.

Definition from ASC 840-10-20

Lease: An agreement conveying the right to use property, plant, or equipment (land and/or depreciable assets) usually for a stated period of time.

Consistent with this definition, power purchase agreements that are dependent on an identified power plant may contain a lease. In contrast, arrangements for which a power facility is not identified (e.g., market-based purchases and sales) are outside the scope of the lease guidance. When evaluating whether an arrangement contains a lease of a power plant, reporting entities should determine whether it meets the following two criteria:

- Depends on an identified power plant (the plant can be explicitly or implicitly specified)
- Conveys to the purchaser the right to control the use of the power plant

This analysis should be performed at the inception of the arrangement (see UP 2.5.1.1 for information on lease inception). This section discusses key concepts in evaluating whether a power purchase agreement meets these criteria.

Question 2-1

Can arrangements that convey the right to a natural resource or assets other than property, plant, or equipment contain a lease?

PwC response

No. As discussed in ASC 840-10-15-15, arrangements that convey the right to a natural resource, such as natural gas, are outside the scope of the lease guidance. In addition, arrangements that transfer the right to use assets other than property, plant, or equipment do not qualify for lease accounting under ASC 840-10-15-15 and should be accounted for under other applicable U.S. GAAP.

Question 2-2

Does the lease guidance apply to contracts for nuclear fuel?

PwC response

Yes. Although lease accounting does not apply to natural resources, including certain fuels such as natural gas or oil, it does apply to nuclear fuel.

Excerpt from ASC 840-10-55-7

A nuclear fuel lease meets the definition of a lease because a nuclear fuel installation constitutes a depreciable asset. Thus, a nuclear fuel lease conveys the right to use a depreciable asset whereas contracts to supply coal or oil do not.

Therefore, reporting entities should evaluate contractual arrangements involving nuclear fuel to determine whether they contain a lease. See UP 14.3 for further information on accounting for nuclear fuel.

Question 2-3

Can a lease involve a portion of a larger asset?

PwC response

Yes. A portion of property, plant, or equipment that is physically distinguishable from the larger asset can be the subject of a lease. For example, an entity may enter into an agreement for the output from one unit of a multiple-unit power facility. “Right-of-way” agreements that grant the right to install, operate, and maintain transmission facilities and distribution assets on land owned by a third party for a specified period are also common in the utility and power industry. These types of arrangements generally meet the definition of a lease on the basis that the transaction involves an explicit portion of a larger, specified asset.

However, arrangements that provide for the use of physical assets are not always leases. Utilities often obtain or grant the right to attach aerial cables, wires, and associated appurtenances to utility poles. These agreements typically do not explicitly identify the exact location of the attachment on the poles, and the attachments can be moved relatively freely. Unless the arrangement specifies a location on the pole, it generally would not meet the definition of a lease.

Question 2-4

Can an undivided interest in a plant be the subject of a lease?

PwC response

Yes. An owner of an undivided interest in a plant (a joint plant arrangement) may enter into a power purchase arrangement to sell the output from its undivided interest, or may otherwise enter into a legal-form lease of its undivided interest. Such arrangements may be for all, or a portion, of the undivided interest. As discussed in UP 15.2, practice in the utility and power industry is to account for undivided interests in a joint plant using proportionate consolidation. Using the proportionate consolidation method, a reporting entity accounts for an undivided interest as if it were a separate unit of property (e.g., the reporting entity’s financial statements include plant and related depreciation expense representing its undivided interest in the plant). Lease accounting applies to separate units of property, plant, or equipment. Therefore, because a joint plant arrangement is accounted for as a separable portion of property, we believe an undivided interest may be the subject of a lease. As such, reporting entities should account for arrangements pertaining to an undivided interest as a lease if the ASC 840 criteria are met. See UP 15.4.2 for further information.

2.2.1 Evaluating other arrangements

Question 2-5

Can pipeline capacity be the subject of a lease?

PwC response

Yes. A pipeline is an identifiable asset that can be used to transport a resource from one location to another. An entity that contracts for the use of all of the capacity of a pipeline has explicitly identified an asset to be used.

If the entity contracts for less than 100 percent of the total capacity, the answer may change. While there is a pipeline identified in the arrangement, the portion of the asset to be utilized under the arrangement cannot be explicitly identified. The portion of the capacity subject to the arrangement is not identifiable or distinguishable from the remaining portion subject to use by other parties. However, should the parties assert that no third party will contract for the remaining capacity of the pipeline over the lease term (e.g., due to regulation, location, or economics), then in substance, one party may be contracting for the full use of the specified asset. This analysis is similar to evaluating which party controls the output of an asset. Refer to UP 2.2.3 for other factors to consider when making this judgment.

2.2.2 Evaluating whether the arrangement is dependent on an identified plant

A lease can exist for accounting purposes only if land or a physical, depreciable asset is identified for the fulfillment of an arrangement. Therefore, in order for a power purchase agreement to be subject to lease accounting, it must be dependent on an identified power plant. Figure 2-1 highlights some key indicators to consider when performing this evaluation.

Figure 2-1

Evaluating whether an agreement involves an identified power plant

Terms	Considerations
Plant is explicitly identified	<ul style="list-style-type: none"> □ Generally, agreements that specify a facility or facilities are dependent on the identified plant. This type of agreement should be evaluated to determine whether it conveys the right to control the use of the identified asset(s). □ Contract terms that allow the seller to supply power from other sources (e.g., from other power plants or from the market) may affect the evaluation of whether the arrangement contains a lease. □ Contract terms that permit replacement power due to scheduled maintenance or unplanned outages would not necessarily preclude a conclusion that the arrangement contains a lease.

Terms	Considerations
Agreement does not specify a source of supply	<ul style="list-style-type: none"> □ Fulfillment of the arrangement may not be dependent on identified plant; further evaluation is required. □ The supplier's ownership of only one power plant or contractual language stipulating the type of power (e.g., natural gas, coal, renewable), location, or non-market-standard terms suggest that a plant is implicitly specified.

The determination of whether a contract involves identified property, plant, or equipment may be straightforward when the agreement specifically identifies a power plant from which the seller will fulfill its obligation. However, the analysis can be more complex when there are contractual, operational, or economic factors that could result in substitution of the specified property by another asset. These considerations are further discussed in the following sections.

2.2.2.1 Plant is explicitly identified

Long-term power purchase agreements often explicitly identify the source of supply. In such cases, the fulfillment of the agreement generally is dependent on the explicitly identified plant. However, prior to concluding that property is identified, the reporting entity should evaluate any contract provisions that permit substitution from an alternative source. For example, due to the nature of a power plant's operations, most power purchase agreements specify the seller's performance requirements during scheduled and unplanned outages. In many cases, the supplier will be permitted to provide replacement power from one of its other power plants or from the market during the periods when the plant is shut down for maintenance or repairs. In other cases, the supplier may have an option to supply the energy from another source, either with permission from the purchaser or at its discretion. Even though a source of supply is explicitly identified, these types of provisions raise questions about whether the arrangement is dependent on an identified facility.

ASC 840-10-15-13 specifically addresses the impact of replacement property on the lease evaluation.

ASC 840-10-15-13

The owner-seller's right and ability to provide goods or services using other property, plant, or equipment does not always mean that the arrangement does not contain a lease. For example, a warranty obligation that permits or requires the substitution of the same or similar property, plant, or equipment if the specified property, plant, or equipment is not operating properly does not preclude lease treatment.

Consistent with this guidance, if a plant is explicitly identified in the arrangement and the ability to provide replacement power from other sources (e.g., a different plant or market purchases) is limited to outage periods, the agreement contains an identified asset. In addition, if replacement power is allowed for reasons other than outages, but it is subject to the consent of the off-taker, or if there are penalties involved in providing replacement power, we would generally conclude that the arrangement

contains identified property. Once the reporting entity determines identified property is involved, it should perform further analysis to determine whether the arrangement conveys the right to control the use of the identified property (see UP 2.2.3).

In contrast, in accordance with ASC 840-10-15-11, the arrangement does not depend on specified property if the supplier can substitute other property at its discretion.

ASC 840-10-15-11

For example, if the owner-seller is obligated to deliver a specified quantity of goods or services and has the right and ability to provide those goods or services using other property, plant, or equipment not specified in the arrangement, then fulfillment of the arrangement is not dependent on the specified property, plant, or equipment and the arrangement does not contain a lease. Most arrangements that call for delivery of an asset that has quoted market prices available in an active market will generally not be dependent on specific property, plant, or equipment to fulfill the arrangement.

If a power purchase agreement allows the seller to substitute power at its discretion with no permission required from the buyer, and there are alternative sources of supply available (e.g., from a different plant or from the market), the arrangement would not contain a lease. However, in accordance with ASC 840-10-15-14, if an arrangement allows for substitution only on or after a specified date, the permitted substitution does not preclude accounting for the arrangement as a lease before the date on which the substitution occurs.

Application examples—identified property

The following examples illustrate the application of the guidance on identified property.

EXAMPLE 2-1

A plant is identified but replacement power is permitted in the event of outages

Ivy Power Producers (IPP) owns and operates the Maple Generating Station, a 500 megawatt (MW) natural gas-fired facility. IPP enters into a 20-year tolling agreement with Rosemary Electric & Gas Company (REG), a regulated utility. Under the terms of the agreement, IPP agrees to sell to REG all of the capacity, electric energy, and ancillary services either available from or produced by the Maple Generating Station. The agreement also provides that IPP may satisfy its obligations from another source only during a forced outage or scheduled maintenance. The agreement includes availability criteria and IPP is required to operate the facility in accordance with prudent utility practice. Failure to meet the contract terms results in market-based penalties for nonperformance.

Is the contract dependent on identified property?

Analysis

The agreement provides REG with the use of the Maple Generating Station for a 20-year period. Although IPP is permitted to provide replacement power in the event of an outage, performance under the agreement is otherwise dependent on the identified property. IPP does not have the ability to control the facility for its own use or for the purpose of satisfying other contractual arrangements. The ability to use replacement property during plant outages is contemplated in ASC 840-10-15-13; therefore, the parties conclude that the agreement is dependent on specified property.

In addition, the conclusion that identified property is involved does not change if the supplier was required (not just permitted) to provide replacement power in the event of an outage.

EXAMPLE 2-2

A plant is identified but replacement power is permitted in the event of outages or with the permission of the off-taker

Assume the same facts as in Example 2-1, except that Ivy Power Producers can supply replacement power at any time with the consent of Rosemary Electric & Gas Company. In addition, it continues to be able to supply replacement power in the event of an outage at the Maple Generating Station.

Is the contract dependent on identified property?

Analysis

This contract is also dependent on identified property, plant, or equipment. As noted in Example 2-1, the ability to provide replacement power in the event of an outage does not affect the conclusion that the agreement is dependent on an identified facility. Furthermore, the ability to provide replacement power with consent still gives the off-taker the ability to control the property, plant, or equipment. IPP cannot use the facility for another purpose at its own discretion and REG has control over whether the facility is used. As such, the parties could conclude that the arrangement involves identified property, plant, or equipment.

EXAMPLE 2-3

A plant is identified but the supplier can substitute an alternative source without permission from the off-taker

Assume the same facts as in Example 2-1, except that Ivy Power Producers can substitute power from other sources at its discretion. There are certain contractual requirements regarding the quality and type of substitute power to ensure compliance with requirements of the applicable regional transmission organization, but there are no other contractual limitations that would prevent substitution.

Is the contract dependent on identified property?

Analysis

Although the arrangement identifies a facility, the supplier's ability to substitute alternative sources at its discretion will usually lead to the conclusion that the arrangement does not involve identified property, plant, or equipment. As discussed in ASC 840-10-15-11, if the supplier has the ability to use other property, plant, or equipment, then fulfillment of the arrangement is not dependent on the property identified in the arrangement. However, in reaching this conclusion, the parties should ensure that alternative sources of supply exist and can be accessed without legal, contractual, or economic penalties. For example, if the identified plant is in an isolated area and it is not economically feasible to supply from another source, the arrangement would involve identified property.

2.2.2.2 *Plant is implicitly identified*

In some cases, an arrangement may contain a lease, even if the property, plant, or equipment is not explicitly identified.

ASC 840-10-15-5

The identification of property, plant, or equipment in the arrangement need not be explicit; it may be implicit. Property, plant, or equipment has been implicitly specified if, for example, the owner-seller owns or leases only one asset with which to fulfill its obligation to the purchaser and it is not economically feasible or practicable for the owner-seller to perform its obligation through the use of alternative property, plant, or equipment.

The lack of a contractually identified facility does not necessarily result in a conclusion that the arrangement does not contain a lease; further evaluation may be required to determine whether a facility is implicitly specified. Key considerations in evaluating whether a plant is implicitly specified are whether it is physically possible to fulfill the contract from another source, and, if so, whether it would be economically feasible to do so.

Some factors that should be considered in performing this evaluation include:

- Was the agreement negotiated based on supplying power from a specific location or facility, and was a power plant built for purposes of servicing the contract?
- Can the supplier access other generating sources, and, if so, is it economically feasible to fulfill the contract from those other sources?
- Does the contract include operational or similar specifications that could be met by only one facility?

- How is the contract priced and would it be economically feasible to fulfill it from the market? For example, assume the supplier owns a coal plant and the marginal market price is based on natural gas-fired generation. If the contract is priced based on generation from a coal-fired facility, it may not be economical to supply from the market. In this case, the supplier's coal-fired facility may be implicitly specified, unless the seller has access to other coal-fired generation.
- Where are the supplier's other potential sources of supply geographically located in relation to the delivery point? Are the plants available to fulfill the contract or are they already contracted to another party? What are the incremental costs of using an alternative source?

In addition, an agreement may include exhibits that contain location maps, delivery points, or plant operating information, or there may be other side agreements that provide further evidence that a plant is implicitly specified.

2.2.3 *Right to control the use of the identified plant*

Once a reporting entity concludes that an arrangement involves identified property, it needs to evaluate whether the agreement conveys to the off-taker the right to control the use of the plant. In accordance with ASC 840-10-15-6, there are three conditions that demonstrate the right to control the use of the plant:

- The purchaser has the right to operate the plant or direct others to operate the plant while obtaining or controlling more than a minor amount of the output.
- The purchaser has the right to control physical access to the plant while obtaining or controlling more than a minor amount of the output.
- It is remote that parties other than the purchaser will take more than a minor amount of the output during the agreement and the pricing in the contract is neither fixed per unit of output, nor equal to the market price per unit of output at the time of delivery.

If the arrangement involves identified property and any of these conditions are met, the arrangement contains a lease. Factors to consider in evaluating whether an arrangement conveys the right to control identified property are further discussed in the following sections. The analysis assumes that the arrangement involves identified property (see UP 2.2.1 for further information).

2.2.3.1 *Right to operate the plant*

ASC 840-10-15-6(a) summarizes key factors to consider when evaluating whether the arrangement conveys the right to operate identified property.

Excerpt from ASC 840-10-15-6(a)

The purchaser has the ability or right to operate the property, plant, or equipment or direct others to operate the property, plant, or equipment in a manner it determines while obtaining or controlling more than a minor amount of the output or other utility of the property, plant, or equipment. The purchaser's ability to operate the property, plant, or equipment may be evidenced by (but is not limited to) the purchaser's ability to hire, fire, or replace the property's operator or the purchaser's ability to specify significant operating policies and procedures in the arrangement with the owner-seller having no ability to change such policies and procedures.

Consistent with these requirements, if the off-taker is responsible for operations and maintenance of the facility, or if it has the ability to select the operations and maintenance provider, it would have the right to operate the facility. The right to dictate significant operating policies also represents the right to operate. In evaluating whether this condition is met, the reporting entity should focus on which party is responsible for performing operations and maintenance (or for hiring and firing the operations and maintenance provider). The unilateral right to make these decisions would convey the right to operate. If a reporting entity controls the right to operate the plant while obtaining more than a minor amount of the output from the plant, the arrangement contains a lease. See UP 2.2.3.3 for information on "more than a minor amount of the output."

Question 2-6

How do operating requirements specified in an arrangement impact the evaluation of the right to operate the facility?

PwC response

Power purchase agreements often specify certain operating requirements, including the obligation to operate and maintain the identified plant following "prudent utility practice." Protective rights over operations generally would not convey the right to operate or control the plant. Examples of such provisions may include:

- Negotiated operating requirements to be executed by the owner
- A requirement to follow prudent operating practices
- A provision that allows the purchaser to monitor the seller's compliance with prudent utility practice, or other safety or environmental standards

However, monitoring rights that allow the purchaser to step in and/or replace the operator for performance issues may demonstrate that the purchaser has the right to operate the plant. See ARM 4650.16 for further information.

Question 2-7

Does the purchaser's ability to control dispatch in a tolling or other power purchase agreement convey the right to operate the plant?

PwC response

It depends. In a typical tolling agreement, the purchaser is responsible for providing fuel to the plant operator for conversion into energy. The off-taker also directs the timing of dispatch. The seller usually is not required to deliver energy unless the fuel is provided. In such cases, we believe that control of operations and maintenance is critical in the evaluation of the "right to operate." The operations and maintenance activities often are performed by the seller. Although the purchaser may have some input into maintenance scheduling and some ability to monitor that the plant follows prudent utility practice, the seller is in control of the operations. Therefore, merely controlling dispatch without rights to control operations and maintenance would not result in a conclusion that the purchaser has the right to control the use of the plant.

Question 2-8

Is the right to operate the plant conveyed to the purchaser if the parties to an agreement share responsibility for operations and maintenance?

PwC response

It depends. In some cases, responsibility for operations and maintenance may be shared by the parties to an agreement (e.g., one party may be responsible for operations and routine maintenance while the other party performs major maintenance). When the parties to the agreement share operating and maintenance responsibilities, a reporting entity should carefully evaluate the rights of each of the parties to determine whether control is conveyed to the purchaser.

In general, we believe that the off-taker would need to have overall control of the most significant operations and maintenance decisions (e.g., through its own performance of these functions, hiring, or firing rights) to be deemed to have control. Control may also be demonstrated through the ability to make the final decision in the event of a dispute between the parties. Control of a portion of the decisions inherently requires coordination and joint decision making between the parties. As a result, many contracts specify veto rights, dispute resolution provisions, or another process to resolve differences of opinion. The specific contractual provisions should be evaluated to determine if the off-taker has substantially all of the decision-making power.

Application example—right to operate

Simplified Example 2-4 illustrates the evaluation of whether the right to operate the plant is conveyed. This example is focused solely on assessing whether the arrangement conveys the right to control operations of the facility or to direct others to do so, and does not consider whether lease accounting would be applicable due to one of the other criteria within ASC 840-10-15-6.

EXAMPLE 2-4

Evaluation of whether the off-taker has the right to operate

Assume the same facts as in Example 2-1, except that the tolling agreement includes the following key terms that are pertinent to evaluating whether the right to control operations is conveyed to Rosemary Electric & Gas Company:

□ *Dispatch*

Ivy Power Producers is obligated to supply power only if fuel is delivered. REG can decide when to call electricity from the facility, subject to operational parameters. If REG does not call the power, IPP retains the right to sell any excess to other purchasers.

□ *Operations and maintenance*

IPP is contractually responsible for the day-to-day operations and maintenance of the plant in accordance with prudent utility practice. IPP will propose timing of all scheduled maintenance and will perform unscheduled maintenance as required. The plant has a management committee that has oversight of the timing of scheduled maintenance, response to system emergencies and forced outages, and other mutually agreed matters impacting operations and maintenance of the facility. Both IPP and REG may designate one or more representatives to this committee; however, each party receives only one vote and unanimous agreement is required.

The parties to the agreement have concluded that the arrangement involves identified property.

Does the agreement convey the right to control operations of the facility or to direct others to do so?

Analysis

IPP is responsible for the day-to-day operations of the facility, and unanimous agreement is required for major decisions impacting operations, including timing of scheduled maintenance and other similar matters. Although REG has the right to dispatch, it does not have the ability to direct the operations of the plant.

2.2.3.2 *Right to control physical access to the plant*

The right to control identified property, plant, or equipment may also be obtained through the ability to control physical access to the asset.

ASC 840-10-15-6(b)

The purchaser has the ability or right to control physical access to the underlying property, plant, or equipment while obtaining or controlling more than a minor amount of the output or other utility of the property, plant, or equipment.

In assessing a typical power arrangement, the right to operate typically also conveys the right to control physical access. Absent unusual conditions, if the seller is the operator of the plant, the agreement generally will not permit the purchaser to control or restrict access to the facility by others. However, if the purchaser operates and maintains the plant, it may have contractual rights that allow it to control physical access. This usually occurs in situations where the power plant is physically located on the purchaser's premises (e.g., a cogeneration facility adjacent to a manufacturing facility or rooftop solar). The purchaser may restrict access to a facility due to highly sensitive or dangerous products on the premises. Alternatively, the purchaser may not want to provide unrestricted access to its building. In certain circumstances, when the seller is the operator of the plant, the purchaser may have contractual rights to restrict physical access. In these situations, the substance of this restriction should be evaluated. Often, this restriction is perfunctory in nature and serves more as a notification requirement than a restriction. Arrangements that have a non-substantive restriction on access to the seller would not meet the condition necessary for control of physical access.

Similar to the right to operate the plant, the condition regarding the right to control physical access is not met unless the purchaser obtains or controls more than a minor amount of the output. See UP 2.2.3.3 for information on "more than a minor amount of the output."

Question 2-9

Is control of the use of the plant conveyed if the power purchase agreement requires the seller to provide the off-taker with physical access to the plant?

PwC response

Generally, no. Power purchase agreements typically allow the purchaser to have access to the plant facilities with advance notice and during business hours. For example, the purchaser may want access to the plant facilities to periodically monitor whether the plant is being run according to prudent utility practice. Although the seller may be required to provide access, that requirement does not provide the purchaser with the right to operate the plant or restrict access to others.

2.2.3.3 *Right to control output*

The right to control identified property, plant, or equipment may also be obtained through the ability to control the output of the asset, subject to certain pricing limitations as discussed in ASC 840-10-15-6(c).

ASC 840-10-15-6(c)

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

Control of the output of an identified facility is the usual trigger for lease accounting in a power purchase agreement. For an agreement to transfer control of the output, it should meet specific criteria related to the amount taken by the off-taker and the pricing of the output. Key factors to consider in assessing whether control is transferred are summarized in Figure 2-2.

Figure 2-2
Evaluating control of the output in a power purchase agreement

Area	Key considerations
Quantity taken by the purchaser	<ul style="list-style-type: none"> □ It is remote that one or more parties other than the purchaser will take more than a minor amount of the output. □ Some facilities produce more than one type of output (e.g., steam and energy) that are sold to different purchasers. In such cases additional analysis is required to determine the fair value of the output being sold to each of the parties. □ Whether renewable energy credits meet the definition of output (if the power purchase agreement involves a renewable energy project, see UP 7.3.2).
Pricing	<ul style="list-style-type: none"> □ The pricing criterion is met (i.e., a lease may exist) if pricing is neither a fixed price per unit of output nor equal to the current market price per unit of output at the time of delivery. □ The reporting entity may elect an accounting policy for how the “fixed price per unit” criterion is evaluated; there are two acceptable methods for making this determination. □ A contract with pricing that has a fixed element and a market component is neither fixed per unit of output nor equal to the current market price per unit of output at the time of delivery.

If the agreement does not meet both the quantity and pricing criteria, control of the output is not transferred. Although these criteria appear straightforward, application can be challenging, as discussed in the following sections.

Quantity of output taken by the purchaser

In evaluating whether a contract transfers control of the output, the first question is whether the purchaser controls all but a minor amount of the output.

Excerpt from ASC 840-10-15-6(c)

Facts and circumstances indicate that it is *remote* that one or more parties other than the purchaser will take *more than a minor amount* of the *output or other utility* that will be produced or generated by the property, plant, or equipment during the term of the arrangement. . . . (emphasis added)

As highlighted in the excerpt, this criterion encompasses three key concepts, each of which should be understood and evaluated in contemplation of one another, and each of which is described below. If substantially all of the output from an identified facility is sold to one party and the contract pricing is neither fixed per unit nor equal to the market price per unit of output at the time of delivery, the arrangement contains a lease. However, many facilities have contracts with more than one counterparty. This may raise questions about how to evaluate this criterion.

Further background on the meaning of the terms, questions and answers on key application issues, as well as selected application examples follow.

Remote

A reporting entity should evaluate whether it is remote, over the term of the arrangement, that one or more parties other than the purchaser will take more than a minor amount of the output. The term “remote” is defined in ASC 840.

Definition from ASC 840-10-20

Remote: The chance of the future event or events occurring is slight.

In application, the term remote is viewed in the same manner as it is used for loss contingencies in ASC 450, *Contingences* (ASC 450). Judgment will often be needed when considering whether it is remote that other parties will take more than a minor amount of the output.

More than a minor amount

ASC 840 does not define the word “minor” or otherwise specify what is meant by the term “more than a minor amount of output.” We believe that 10 percent or more of the output to be produced by a power plant over the term of the contractual arrangement would constitute more than a minor amount of the output. This assessment is performed at the inception of the arrangement or when reassessment is required. As described in ASC 840-10-15-6(c), the evaluation should be based on the amount “that will be produced or generated by the property, plant, or equipment during the term of the arrangement,” not the maximum capacity.

Therefore, if the facility is expected to run at only partial capacity, that is all the capacity that should be considered in the assessment. Any potential future increase in the physical capacity of the plant would not be considered at the inception of the

arrangement, although a future increase would cause the purchaser and seller to perform a reassessment (see UP 2.4).

Output or other utility

Power purchase agreements often comprise the sale of multiple products, which may include energy, capacity, steam, renewable energy credits, and ancillary services. It is not uncommon for an entity to sell products from a facility to more than one counterparty. In evaluating whether an arrangement conveys the right to control the use of an identified property, a reporting entity should determine whether the rights conveyed involve the “output” from the facility. Whether a product being sold under a power purchase agreement is considered output or other utility of the plant may be subject to judgment, and the conclusion can affect whether the arrangement qualifies as a lease. The following table summarizes considerations when assessing some of the potential outputs from a power plant.

Figure 2-3
Which products are output?

Product	Output?	Considerations
Ancillary services	Yes	Ancillary services (e.g., regulation market or synchronized reserve market) are provided from the dedication and operation of a specific facility. See UP 4.5 for further information about ancillary services in general.
Capacity	Yes	“Iron in the ground” is required to provide capacity; capacity represents the dedication of a specific plant to a counterparty or to a control area to meet reserve requirements and customer needs.
Energy	Yes	Electric energy is produced and delivered to customers from power plants.
Renewable energy credits	It depends	Whether renewable energy credits are output is subject to an accounting policy election. See discussion below and UP 7.3.2 for further information.
Steam	Yes	Steam is a tangible product; however, it is usually insignificant to the total economics of the facility.
Other government incentives	Generally, no	Government incentives are typically paid or awarded to the owner of a facility and are not physically produced or transferable. Examples include tax credits, grants, and other programs that incentivize green power.

As summarized in Figure 2-3, substantially all of the products sold from a power plant are considered output or other utility of the plant. However, whether RECs are considered output depends on the reporting entity's accounting policy. Some believe that RECs are output because they are an important element of the overall economics of a facility. Others believe that RECs are a government-supported incentive.

We believe that both views have merit and that there is support for each of the positions. Therefore, we believe that the determination of whether RECs are output is an accounting policy election. However, although the view that RECs are a government incentive has been broadly vetted and accepted, we understand that the SEC staff has not reached a conclusion regarding this view. See UP 7.3.2.

Other economic or environmental benefits received in connection with the operation of a power plant are generally not considered output of the plant. For example, a power plant that is compensated for utilizing industrial or agricultural waste as a fuel source to generate electricity should not consider that economic benefit when evaluating the party obtaining the plant output. Even if the plant was built for the sole purpose of disposing of the waste, the output of the plant in this circumstance is the electricity. The receipt of consideration for consuming the waste is incidental to the asset's production of output.

Question 2-10

How should a reporting entity evaluate "more than a minor amount"?

PwC response

As discussed above, we believe that more than 10 percent of the output to be produced by a facility would constitute more than a minor amount. The 10 percent calculation is simple if a facility is selling only one product; however, power plants often produce and sell at least three products: energy, capacity, and ancillary services. Because the different products have different units of physical measurement, we believe that the reporting entity should assess the fair value of each of the expected outputs in performing the output analysis.

In assessing the relative fair value of the output from the facility, the numerator and denominator used in the calculation should be expressed in units of currency (e.g., in dollars), rather than the unit of measure associated with the output (e.g., megawatt-hours or number of RECs). The calculation is based on the fair value of a reasonable expectation of sales (rather than stated capacity) over the life of the contract (as determined at the contract's inception). This would consider the maximum rate of capacity of the plant and other factors such as maintenance schedules, and the type of plant and its scheduled use. For ease of calculation, we believe it is acceptable to base the calculation on actual or projected revenue over the contract term.

Question 2-11

How should a reporting entity evaluate “more than a minor amount” of output if the users of the facility may change during the term of the arrangement?

PwC response

A power plant or similar facility may contract with one party for less than 90 percent of the output. The owner may intend to sell the remainder of the output in the market or to another off-taker. In these circumstances, it may be difficult to assess whether it is remote that another purchaser will take more than a minor amount of the output. Considerations in making this assessment include:

Economic factors

The overall economics of the arrangement are one of the key factors to consider in determining whether control has been transferred.

ASC 840-10-55-34

All evidence should be considered when making the assessment as to the possibility that other parties will take more than a minor amount of the output, including evidence provided by the arrangement’s pricing. For example, if an arrangement’s pricing provides for a fixed capacity charge designed to recover the supplier’s capital investment in the subject property, plant, or equipment, the pricing may be persuasive evidence that it is remote that parties other than the purchaser will take more than a minor amount of the output or other utility that will be produced or generated by the property, plant, or equipment.

As noted in the excerpt, if an arrangement is designed to allow the owner to recover its investment in the facility, it may be remote that another party is going to take more than a minor amount of the output. In contrast, if the off-taker is purchasing only 70 percent of the output, and the arrangement does not cover the full cost of operation, the owner may need to sell the additional capacity to others to be able to recover its costs.

Market sales

The reporting entity should consider the location of the market and, thus, its implications for the cost of transmission or transportation, and the relative cost of production of the facility compared with market prices (i.e., the cost of production from the facility relative to the market and whether and how often sales to the market would be economical). Key considerations include whether there is a liquid market that the producer can access from the facility and whether sales to the market are economically feasible in sufficient quantities that such sales would comprise more than a minor amount of the output. Historical information on market sales from the facility or other similar facilities may be helpful in performing this evaluation.

Other potential purchasers

Another consideration is whether there are other potential off-takers from the facility. A plant that is selling to the only utility in the area may have difficulty in identifying another purchaser for excess capacity. In contrast, a renewable energy facility located in a jurisdiction where the regulated utilities are mandated to purchase renewable power, and with transmission access to a liquid hub, may have multiple potential buyers.

EXAMPLE 2-5**Exposure to pricing variability of output without physical delivery**

Rosemary Electric & Gas (REG) operates in a state with annual renewable energy targets. REG contracts with Wisteria Wind Power to purchase all of the RECs generated from Wisteria's wind farm to meet its regulatory requirements. To ensure sufficient recovery of its capital costs, Wisteria requires that REG also commit to purchase all of the energy associated with the wind farm at a fixed price that escalates annually. REG follows a "fixed equals fixed" policy regarding pricing (see Figure 2-4). REG does not need any of the energy to meet its load requirements and instead directs Wisteria to sell the power into the market. REG is responsible for the market price changes from the contractually agreed pricing. Should market prices rise above the contractually fixed pricing, Wisteria will provide REG with those benefits, and if market prices fall below the contractually fixed pricing, REG will pay Wisteria the difference between market prices and the contractually fixed pricing. REG does not take physical delivery of any of the energy produced by the windfarm.

Does the arrangement contain a lease?

Analysis

The arrangement contains a lease despite the fact that REG does not take physical delivery of any of the energy generated by the asset under contract. REG is economically exposed to 100% of the windfarms output through this contract. The substance of the arrangement is that REG is purchasing 100% of the output and reselling the energy into the market.

EXAMPLE 2-6**Economic exposure to output without physical delivery**

Assume the same facts as Example 2-5, except that instead of directing Wisteria to sell the energy into the market, REG has contracted with Ivy Power Producer (IPP) to purchase all of the energy. IPP receives the energy from Wisteria and pays Wisteria directly. If IPP defaults by failing to make its payment to Wisteria, REG is responsible for making the payment to Wisteria for any shortfall.

Does the arrangement contain a lease?

Analysis

The arrangement contains a lease for REG. Similar to Example 2-5, REG is not relieved of the obligation to pay for 100% of the output from the facility despite IPP taking physical possession. Regardless of the probability of default by IPP, the economic exposure to Wisteria contractually resides with REG.

EXAMPLE 2-7*Assigning rights for output under a separate contract*

Assume the same facts as Example 2-6, except that Wisteria has released REG as the primary obligor for energy payments. IPP is the primary obligated party to the sales of energy from Wisteria. In this case, REG has no economic exposure related to the energy sales to Wisteria if IPP fails to make payments. It is presumed that the energy portion of the output is more than a minor amount of the fair value of the output.

Does the arrangement contain a lease?

Analysis

The arrangement does not contain a lease for REG. In this case, REG no longer has any economic exposure to the physical output of the facility beyond its purchase of the RECs. IPP has responsibility to take delivery and pay for all of the energy and has relieved REG of any economic benefit or detriment.

Contract pricing

If the pricing of the contract is either fixed per unit of output or market price per unit of output at the time of delivery, control of the use of the facility is not conveyed.

Excerpt from ASC 840-10-15-6(c)

The price that the purchaser (lessee) will pay for the output is neither contractually fixed per unit of output nor equal to the current market price per unit of output as of the time of delivery of the output.

One of the characteristics used to distinguish between leases and service contracts is pricing. Contracts that have fixed or market-based pricing would not necessarily cover the costs of operations and the right to control the use of the identified asset would not be transferred. Note that a combination of fixed- and market-based pricing would not qualify as either fixed per unit of output or market price per unit of output at the time of delivery. Additionally, if there are multiple contracts entered into at the same time and in contemplation of each other, the pricing associated with all lease output deliverables under all of the arrangements would need to be considered.

In evaluating whether this criterion is met, questions often arise regarding the meaning of “contractually fixed per unit of output.” At the time of adoption of EITF

01-8, “fixed per unit of output” was usually interpreted following the “fixed equals fixed methodology” (see Figure 2-4).

In recent years, there has been significant discussion about the meaning of fixed and whether a different interpretation would be acceptable. Some of the discussion was prompted by the development of a broader interpretation of the word “fixed” in applying International Accounting Standard (IAS) 32, *Financial Instruments: Presentation*. That standard distinguishes financial instruments to be accounted for as liabilities from those that are to be accounted for as equity. Many felt that the flexibility in interpreting the word “fixed” in that context should extend to interpreting the same word in the context of IFRS Interpretations Committee 4, *Determining whether an Arrangement contains a Lease* (IFRIC 4), which is the International Financial Reporting Standards (IFRS) equivalent of ASC 840-10-15. As a result of these discussions, an alternative view exists for interpreting “fixed per unit of output.”

As summarized in Figure 2-4, “fixed” may be interpreted as meaning that the amount is exactly the same throughout the contract (“fixed equals fixed”) or that it means predetermined at contract inception (“fixed equals predetermined”).

Figure 2-4
Application of “contractually fixed per unit of output” interpretation

	Fixed equals fixed	Fixed equals predetermined
Interpretation	“Fixed” is interpreted in a manner that allows for no variability whatsoever in pricing	The “fixed” criterion is met if, at the inception of the arrangement, the purchaser and seller can determine what the exact price will be for each and every unit of output sold at each point in time during the term of the arrangement
Impact	Applies only when the pricing is a flat amount per unit for the entire term of the contract (e.g., \$50/megawatt-hour (MWh) for every megawatt received under the contract)	Applies if the only variability in pricing is time (e.g., power delivered in 20X1 is \$50/MWh, power delivered in 20X2 is \$55/MWh)
Application	Would not apply if price constituted a monthly fixed payment for capacity plus separate payments for energy, but amount of energy delivered could vary	Any variability due to factors other than time, such as volume or cost, would not qualify

We believe that both views are acceptable and that the interpretation of “fixed” per unit of output is an accounting policy election. However, if payments are designed in a manner to provide for capital recovery or repayment of the seller’s debt (e.g., a front-

loaded schedule of payments), a reporting entity should consider whether it is appropriate to apply a fixed equals predetermined approach.

The accounting policy election should be applied consistently, assuming reasonably similar facts and circumstances, and should also be disclosed. Common questions about how to determine if a contract has “fixed” pricing, as well as the impact of a change in policy are included below, followed by interpretive examples.

Question 2-12

What is the impact, if any, of default penalties or provisions on the “contractually fixed per unit of output” conclusion?

PwC response

It depends. Certain power purchase agreements may have default provisions that change the predetermined pricing under the contract. For example, the supplier may be required to refund previously received payments or make other penalty payments due to a shortfall in production. Any penalty for nonperformance that could change the price per megawatt-hour over the term of the contract would result in pricing that is not fixed per unit. This would be the case even if the amount of the default penalty is not specified in the contract (i.e., the penalty is commercially determined and agreed to at the time of default).

Other contracts may include default penalties or liquidated damages in the event of termination of the agreement. If the termination amount paid or received is based only on lost or foregone future production over the remaining term of the contract, we believe such penalties would not by themselves cause a conclusion that the price per unit of output is not contractually fixed. This is because the fixed price paid for the output previously obtained from the lease prior to the termination is not impacted by the termination. However, if the penalty includes any input or factor based on past quantities or deliveries, the pricing would not be contractually fixed per unit because the penalty would modify the amounts previously paid, as opposed to being considered compensation for future output that will not be delivered.

Question 2-13

What are some of the considerations if a reporting entity is considering changing its accounting policy on how “fixed” per unit of output is interpreted?

PwC response

Adoption of a new method for evaluating “fixed” per unit of output is a change in accounting method, which would be accounted for as a change in accounting principle in accordance with ASC 250, *Accounting Changes and Error Corrections* (ASC 250). To adopt a change in method, a reporting entity would have to conclude that the new method is preferable and, if the reporting entity is an SEC registrant, it would have to obtain a preferability letter. In addition, in accordance with ASC 250, a change requires full retrospective application, unless it is not practicable to do so.

The method adopted to interpret the term “contractually fixed per unit of output” may significantly impact the accounting for certain arrangements because some contracts that would otherwise contain a lease under the “fixed equals fixed” method may not under the “fixed equals predetermined” method. For example, if an arrangement is no longer viewed as containing a lease (due to changing to a “fixed equals predetermined” accounting policy) the pattern of revenue or expense recognition for the power purchase agreement may change. Similarly, the change may impact the conclusions as to (1) who should consolidate a seller entity that is a variable interest entity and (2) whether the contract contains a derivative to be accounted for separately. All follow-on effects should be considered in determining whether a potential change in accounting method would be material to the financial statements.

In considering whether to adopt a different view, we recommend that reporting entities evaluate the potential accounting outcomes. Figure 2-5 summarizes key factors to consider.

Figure 2-5

Key considerations in evaluating a change in the “contractually fixed price per unit of output” accounting policy

Area	Impact
Scope	<ul style="list-style-type: none"> □ Applicable to all contracts; a reporting entity may not adopt selectively for certain types of contracts or activities □ Election should be consistent across a consolidated group □ Each contract that contains a lease within the scope of the guidance in ASC 840 would be reevaluated under the new policy as of the inception of the contract and each reassessment date if applicable (excludes leases grandfathered by ASC 840)
Transition	<ul style="list-style-type: none"> □ Retrospective application to all periods presented is required unless impracticable; due to the nature of these contracts (i.e., needed information is typically contained within the contracts), we would expect impracticability situations to be rare □ If a different view changes the original lease conclusion, accounting for that transaction would be revised for all impacted periods

Area	Impact
Accounting implications	<p>New nonlease classification may change recognition, even if the lease was previously accounted for as an operating lease:</p> <ul style="list-style-type: none"> <input type="checkbox"/> Lease recognition pattern would be reversed <input type="checkbox"/> Derivative accounting may be applicable <input type="checkbox"/> Long-term power purchase agreement guidance may change revenue recognition if executory contract accounting applies (ASC 980-605-25)¹ <input type="checkbox"/> Variable interest entity conclusions may need to be reconsidered if lease conclusion changes (see UP 10)

In addition, reporting entities should consider the potential impact of the changes on financial statement metrics and compliance with debt covenants.

Question 2-14

Could the normal purchases and normal sales scope exception apply to a contract that is no longer viewed as containing a lease and that is therefore subject to derivative accounting due to a change in accounting policy?

PwC response

It depends. As a result of adopting a new accounting policy relating to the “fixed” pricing criterion, certain contracts that were previously deemed to contain leases may now be subject to derivative accounting treatment. If the reporting entity concludes that the contract is now a derivative in its entirety, or contains an embedded derivative that requires separation from the host contract, the contract would be recorded at fair value as of the later of the date of retrospective application and the effective date of the contract. ASC 815-10-25-2 states:²

ASC 815-10-25-2

If a contract that did not meet the definition of a derivative instrument at acquisition by the entity meets the definition of a derivative instrument after acquisition by the entity, the contract shall be recognized immediately as either an asset or liability with the offsetting entry recorded in earnings.

Changes in fair value subsequent to the date the contract becomes a derivative will flow through the income statement. The derivative may be subsequently designated as

¹ Guidance originally issued in EITF 91-6 and EITF 96-17. This guidance has been primarily codified as ASC 980-605-25-5 through 25-15 and ASC 980-605-25-17 and 25-18, respectively.

² Guidance originally issued in Derivatives Implementation Group (DIG) Issue A18, *Definition of a Derivative: Application of Market Mechanism and Readily Convertible to Cash Subsequent to the Inception or Acquisition of a Contract*.

a hedge or a normal purchase and normal sale; however, these designations generally would not change the initial accounting for the derivative.

Some reporting entities may conditionally designate all qualifying contracts as normal purchases and normal sales in case derivative accounting ever becomes applicable. If the contract qualifies and was previously conditionally designated as a normal purchase or normal sale, then we believe that no fair value accounting would be required. Absent this prior designation, the reporting entity would record the contract at fair value as of the date of retrospective application with subsequent changes in fair value recorded in income. Because the normal purchases and normal sales scope exception is an election, the reporting entity could, upon changing its policy, document the exception and apply it to future periods (periods after the date of the designation). See the response to Question 3-19 for further information about conditionally designating a contract as a normal purchase or normal sale.

Similarly, a hedge relationship could be designated at the time of adopting the new policy. In such cases, if the hedge is effective, changes in fair value occurring after the date of designation would be recognized in other comprehensive income. However, depending on the age of the contract and its pricing, it will likely no longer be “at market” and, as a result, may create enough ineffectiveness such that the hedge would not qualify for hedge accounting. See UP 3.5.4 for information about evaluating hedge effectiveness.

Application examples—contractually fixed per unit of output

EXAMPLE 2-8

Pricing arrangements considered “contractually fixed per unit of output” under the fixed equals predetermined view

Ivy Power Producers (IPP) constructs the Wisteria Wind Power Project, a 40 MW wind facility. It enters into a 25-year power purchase agreement to sell all of the electric energy and renewable energy credits generated by the facility to Rosemary Electric & Gas Company (REG). For purposes of this example, REG pays a bundled price for energy and renewable energy credits. REG pays only for amounts delivered and is required to take all energy and RECs produced. There is no separate capacity payment and no minimum energy or capacity specified in the contract. Pricing does not vary by volume produced or by IPP’s cost.

What pricing provision would qualify as “contractually fixed per unit of output” under the fixed equals predetermined view?

Analysis

Under the “fixed equals predetermined” method, all of the following examples of pricing arrangements would qualify as contractually fixed per unit of output.

- a) \$40/MWh in year one, escalated each year by \$1/MWh.
- b) \$40/MWh in year one, escalated each year by a fixed percentage.

- c) \$75/MWh for on-peak power and \$45/MWh for off-peak power during the entire term of the contract. The contract specifically defines the on-peak period based on time, for example, 8:00 a.m. through midnight, Monday through Saturday, during the months of July, August, and September. All other periods are off-peak.
- d) Pricing is established based on the following defined schedule included in the contract:

Super-peak (4:00 p.m.–8:00 p.m.)	On-peak (8:00 a.m.–midnight, except super peak)	Off-peak (midnight–8:00 a.m.)
\$45	\$42	\$25
50	45	25
90	75	40
75	70	35
45	42	25

- e) Pricing is similar to example (d) except that the matrix pricing applies only during the initial 5 years of the arrangement. Thereafter, all prices in the matrix will increase by 10 percent for each successive 5-year period.

All of these pricing schemes would qualify as fixed per unit of output under the “fixed equals predetermined” method; however, none of the examples would qualify as fixed under the “fixed equals fixed” interpretation. Therefore, the accounting for the contract would depend on the accounting policy elections made by IPP and REG. In addition, the parties to the contract would need to evaluate the contractual terms in accordance with the other criteria in ASC 840-10-15-6 to determine if the contract contains a lease.

EXAMPLE 2-9

Pricing arrangements that would not be considered “contractually fixed per unit of output”

Assume the same facts as in Example 2-8, except as noted below.

What pricing provision would not qualify as “contractually fixed per unit of output” under the fixed equals predetermined view?

Analysis

The following proposed pricing would not qualify as contractually fixed per unit of output:

- a) \$40/MWh in year one, escalated annually by \$1/MWh. The off-taker, REG, is also required to pay a \$30,000 per month capacity charge. The capacity charge is not

payable for any month that the owner-operator, IPP, does not maintain a capacity factor of at least 30 percent.

The pricing in this arrangement would not be considered predetermined because the price per megawatt-hour will vary with the amount of energy produced. Although the energy price is fixed, the amount paid per megawatt-hour includes the fee for capacity and monthly changes in production would change the average cost per megawatt-hour. For example, if the plant produced 15,000 megawatt-hours in the first month, the price would be \$42/MWh (\$40/MWh energy charge plus \$2/MWh allocated capacity charge (\$30,000/15,000 MWhs)). However, if the plant only produced 10,000 megawatt-hours, the price would be \$43/MWh.

- b) \$40/MWh in year one, escalated annually by changes in the Consumer Price Index (CPI).

The economics of this fact pattern would be similar to Example 2-8(b), if it were expected that the Consumer Price Index would increase at an average rate of approximately 2.5 percent per year. However, in Example 2-8(b), the price was predetermined, which is not the case in this example.

- c) \$75/MWh for on-peak power and \$45/MWh for off-peak power during the entire term of the contract. On-peak pricing would apply whenever total demand for electricity exceeds 10,000 megawatt-hours. Off-peak pricing would apply at all other times.

This fact pattern is similar to Example 2-8(c), except that the price per megawatt-hour would vary based on a factor other than timing. In this case, the factor would be demand. As a result, at the inception of the contract, the buyer and the seller would not be able to determine the exact price for every unit of output sold during the term of the arrangement. As such, the price would not be considered contractually fixed per unit of output.

- d) \$40/MWh for the entire term of the contract. However, the plant owner, IPP, is required to refund \$1/MWh if the capacity factor drops below 30% over a rolling 2-year period.

In this fact pattern, the price per megawatt-hour may change based on the availability of the Wisteria Wind Power Project. If availability drops below a certain amount, the price per megawatt-hour for the period would decrease to \$39/MWh. The look-back provision ties pricing to production from the facility; therefore, the price would not be considered predetermined per unit of output.

This simplified example includes sample pricing arrangements that all include some factor other than timing that could change the price paid per megawatt-hour. As a result, the fixed price exception is not met under either interpretation of “fixed per unit of output.”

EXAMPLE 2-10

Additional pricing arrangements that would not be considered “contractually fixed per unit of output”

IPP and REG enter into a 10-year power purchase agreement for all of the output from Maple Generating Station, a 500 MW natural gas-fired power plant.

What pricing provision would not qualify as “contractually fixed per unit of output”?

Analysis

The following examples of pricing provision would not qualify as “contractually fixed per unit of output.”

- a) \$40/MWh in year one, escalated each year on January 1 based on the year-over-year change in the January monthly Henry Hub natural gas price index.

This pricing is not considered “fixed per unit of output” because the price per megawatt-hour of electricity in years 2 through 10 would not be predetermined at the inception of the arrangement.

- b) The agreement is structured as a tolling arrangement, such that REG supplies all natural gas required for generation. REG pays a fixed capacity charge of \$2 million per month over the term of the arrangement, escalated annually by 2.5 percent. REG also pays a variable charge of \$10/MWh for delivered energy. The variable charge is also escalated by 2.5 percent.

This pricing would not be considered “fixed per unit of output.” Similar to Example 2-9(a), although the pricing is predetermined, the charge per megawatt-hour would vary with the amount of energy taken under the agreement.

2.3 Allocation of consideration

As discussed in UP 1, the first step in allocating contract consideration is to allocate fair value to any derivative elements. Once that allocation is complete, if an arrangement contains a lease, a reporting entity will need to allocate the consideration paid or received between the lease and the nonderivative, nonlease elements. This allocation will affect lease classification as well as ongoing recognition of revenue (or expense, from the perspective of the off-taker).

Figure 2-6 summarizes key guidance to consider in determining the appropriate allocation related to the lease elements. See also Figure 1-3 for further information on the overall allocation process among all contract elements.

Figure 2-6
Allocating lease consideration

Element	Allocation considerations
Allocate relative fair value between lease and nonlease elements	<ul style="list-style-type: none"> □ Overall allocation—In accordance with ASC 840-10-15-19, total consideration should be allocated between the lease elements (lease of property and related executory costs) and nonlease elements (other products and services included in the contract), based on relative fair value in accordance with ASC 605-25-15-3A. □ There are three acceptable methods of allocating between lease and nonlease elements—(1) variable expected volume method; (2) fixed expected volume method; and (3) minimum volume method (see ARM 4650.161). □ Nonlease elements—The allocation of consideration among the nonlease elements should follow the guidance for derivatives or multiple-element arrangements as applicable. □ The categorization of RECs as lease or nonlease elements will vary depending on whether the reporting entity believes RECs are output (lease element) or a government grant (nonlease element).
Allocate among lease elements	<ul style="list-style-type: none"> □ First allocate lease payments to the executory costs, including profit thereon, based on the contractual terms, if stated, or estimated based on best available information. □ The amount remaining is assigned to lease payments, assuming there are no contingent rentals.

The allocation process requires an understanding of the economics of the arrangement and each step is followed in order. In particular, when a power purchase agreement contains a lease, the allocation should reflect the fact that the arrangement represents use of the facility even if the reporting entity considers the arrangement to be the sale of energy and capacity.

As noted in Figure 2-6, a reporting entity can use one of three acceptable methods to allocate consideration between the lease and nonlease elements. In cases where there is uncertainty about the ultimate level of deliveries (such as a power purchase agreement that contains a fixed capacity charge and variable payments for energy), the minimum volume method is often used. The minimum volume method provides a logical allocation method based on contractual minimum volumes and assists with the complexity due to uncertain future rentals.

2.3.1 *Application example—allocation between lease and nonlease elements*

Simplified Example 2-11 illustrates how to perform an allocation between lease and nonderivative, nonlease elements using the minimum volume method.

EXAMPLE 2-11

Allocating consideration to lease and nonlease elements

Rosemary Electric & Gas Company (REG) enters into a 20-year power purchase agreement with Ivy Power Producers (IPP) to purchase 100 percent of the output from IPP's newly constructed natural gas-fired power plant, the Camellia Generating Station. For purposes of this example, assume that REG is not considered the owner of the plant during construction (see UP 2.5.1.3). The pricing of the arrangement includes a \$250,000 per month fixed capacity charge and a variable payment on actual deliveries with minimum annual quantities of 60,000 megawatt-hours.

IPP will be responsible for the operations and maintenance, as well as procuring the fuel required to run the facility. REG has concluded that the arrangement contains a lease because a plant is identified, REG will take all of the output, and pricing is not fixed per unit or equal to the current market price per unit of output at the time of delivery.

Total consideration over the life of the agreement is estimated to be approximately \$84 million. Based on minimum volume, the fair value of the lease elements are estimated to be \$65 million (based on the market rents of the plant at inception of the arrangement and including \$6 million for executory costs). The fair value of the nonlease elements is estimated to be \$35 million (based on the market price for similar service agreements, including fuel).

How should consideration be allocated between the lease and nonlease elements?

Analysis

The contract has the following elements:

- Lease elements—energy and capacity, including executory costs (taxes, maintenance, and insurance)
- Nonlease elements—operation of the facility, including materials and fuel costs

REG would allocate the total consideration based on relative fair value:

- Lease elements— $\$65/(\$65 + \$35) \times \$84 \text{ million} = \$54.6 \text{ million}$
- Nonlease elements— $\$35/(\$65 + \$35) \times \$84 \text{ million} = \$29.4 \text{ million}$

Accordingly, \$54.6 million would be allocated to the lease of the facility. While the executory costs of \$6 million would be included in determining the allocation, they would be excluded in order to determine the minimum lease payments for the purpose of classifying and accounting for the lease.

This simplified example is only one acceptable method for allocating the consideration between the lease and nonlease elements. Other methods may also be acceptable provided they capture the economics of the arrangement. We would expect the method adopted to be consistently applied to similarly structured arrangements.

Question 2-15

Does major maintenance represent a lease-related executory cost or a nonlease element?

PwC response

Executory costs are described in ASC 840 as including insurance, maintenance, and taxes to be paid to the lessor. However, as discussed in Issue Summary No. 1 of EITF 08-2, *Lessor Revenue Recognition for Maintenance Services*,³ some believe that major maintenance or non-routine maintenance may be so significant that those services should not be considered a lease-related executory cost, but should be considered “other services.” As there is no definitive guidance, accounting for major maintenance as an executory cost or a nonlease element is an accounting policy election that should be applied consistently. Accounting for major maintenance as part of the nonlease elements would require an allocation of consideration on a relative fair value basis. Conversely, accounting for major maintenance as an executory cost (i.e., a separate lease element) would require an estimated allocation of consideration. Refer to Figure 2-6 above for guidance on allocating lease consideration.

Question 2-16

How should lessors recognize revenue associated with payments received for major maintenance when those amounts are considered executory costs?

PwC response

As discussed in Question 2-15, whether major maintenance is considered an executory cost or a nonlease element is an accounting policy election. For major maintenance accounted for as a lease-related executory cost (a lease element), ASC 840 does not provide specific guidance regarding the manner in which a lessor should recognize revenue. However, Section 9.45 through 9.52 of the AICPA Audit and Accounting Guide for the Airlines Industry indicates that both a proportional performance approach and a straight-line basis are acceptable methods. Additionally, Issue Summary No. 1 of EITF 08-2, *Lessor Revenue Recognition for Maintenance Services*, although no consensus was reached, discussed the following alternatives:

- View A: Revenue related to maintenance services should be recognized into income over the lease term in proportion to the costs expected to be incurred in performing maintenance services under the contract. If that pattern cannot be

³ The EITF never reached a consensus on this Issue and the project was removed from the EITF’s agenda with no conclusions reached.

reliably determined, maintenance services should be recognized into income on a straight-line basis over the lease term unless another systematic and rational allocation basis is more representative of the pattern in which the costs of performing maintenance services under the contract are incurred.

- View B: Revenue related to maintenance services should be recognized into income as those services are performed utilizing a proportional performance method that is determined to be the most appropriate method under the circumstances.
- View C: The minimum maintenance payments over the lease term should be recognized into income over the lease term on a straight-line basis. Contingent maintenance payments should be recognized as they accrue.

Although a final consensus was not reached, the EITF tentatively concluded that revenue should be recognized in accordance with View B (proportional performance method) before the issue was removed from its agenda. We believe that reporting entities should apply the method that is reasonable and supportable given the specific facts and circumstances.

2.4 *Reassessing whether an arrangement contains a lease*

After a reporting entity performs the initial assessment of whether a power purchase agreement contains a lease, ASC 840-10-35-2 requires a reassessment only if one of the following events occurs:

- There is a change in contractual terms.
- There is a negotiated renewal or extension of the contract (a renewal or extension that does not modify the original terms would result in an evaluation performed only for the renewal or extension period).
- There is a change in the determination as to whether fulfillment of the power purchase agreement is dependent on the identified plant.
- There has been a substantial physical change to the identified plant.

The occurrence of one of these events would require an evaluation by both parties to the contract, based on the facts and circumstances as of the date of reassessment. If the arrangement is deemed to contain a lease, lease accounting is applied prospectively as of the date of reassessment.

Key factors to consider in determining whether a reassessment is required are summarized in Figure 2-7. In addition to the events summarized in Figure 2-7, which impact all contracts, there are additional requirements for reassessment of contracts grandfathered at the time of adoption of EITF 01-8 (see UP 2.4.1).

Figure 2-7
Reassessment events—key considerations

Reassessment event	Key considerations
Change in contractual terms (UP 2.4.2)	<ul style="list-style-type: none"> □ Changes can be formal (executed modification to the contract) or informal (verbal agreement between the parties). □ A modification of terms results in the loss of “grandfathering” of a contract executed prior to the effective date of the guidance originally issued as EITF 01-8, and reassessment is required (see UP 2.4.1). □ A renewal or extension that does not change the contract terms is not a modification; however, see renewal considerations below.
Contract renewal or extension (UP 2.4.3)	<ul style="list-style-type: none"> □ The exercise of a renewal or extension option that was present in the original agreement is not a change in contractual terms and would not trigger a reassessment of whether the arrangement contains a lease (however, if the contract was originally accounted for as a lease, the renewal or extension would cause it to be accounted for as a new lease). □ A subsequently negotiated renewal or extension that does not modify the terms in the original agreement before the end of the original term is evaluated only for the renewal or extension period; existing accounting for the original term remains in place.
Arrangement is no longer dependent on the identified property (UP 2.4.4)	<ul style="list-style-type: none"> □ Changes in market conditions (e.g., it becomes economically feasible to fulfill the contract from a liquid market or other generating source) could trigger reassessment.
Physical change to the plant (UP 2.4.5)	<ul style="list-style-type: none"> □ Increasing the capacity of the plant (or decreasing it by shutting down units) would cause a reassessment. □ Adding or removing a physically distinct unit (e.g., a new unit to a generating station) would be ignored if the arrangement remains dependent on one or more other units.

Reassessment considerations unique to utilities and power companies are discussed below. In addition, ASC 840-10-55-35 through 55-37 provide examples to illustrate the reassessment guidance.

Question 2-17

Is reassessment of an arrangement required if there is a change to the amount of output taken by the users of the identified facility?

PwC response

Generally, no. Often, the conclusion about whether an arrangement contains a lease will depend on whether it is remote that another party will take more than a minor amount of the output from the identified facility. This is generally a straightforward evaluation when the off-taker has contracted for 90 percent or more of the output. However, if the off-taker has contracted for less than 90 percent of the facility's output, judgment is necessary to assess whether the excess capacity will be sold (either to the market or to another user). If the actual level of sales to another party differs from the original forecast (e.g., a portion of the facility is later contracted to another party), a question arises as to whether this requires a reassessment of the lease conclusion.

The conclusion about whether and at what amount output will be delivered to other users is inherently an estimate made at the beginning of the contract term. Subsequent changes in these estimates are specifically addressed in the lease guidance.

Excerpt from ASC 840-10-35-3

Changes in estimate (for example, the estimated amount of output to be delivered to the purchaser or other potential purchasers) shall not trigger a reassessment.

Consistent with this guidance, no reassessment is required if there are differences between actual sales to another party and the original assessment. However, because this involves an estimate, reporting entities should ensure that the original assessment is robust, includes a careful analysis based on all available information, and is well documented. Significant differences from the original forecast may require reevaluation of the original conclusion.

2.4.1 *Contracts grandfathered at time of adoption of EITF 01-8*

The guidance on determining whether an arrangement contains a lease was originally issued as EITF 01-8 and was codified in ASC 840. The guidance should be applied to arrangements agreed to or committed to, if earlier, after the beginning of an entity's next reporting period beginning after May 28, 2003 (July 1, 2003 for an entity with a calendar year-end). In accordance with this transition guidance, if an arrangement was entered into prior to the EITF 01-8 transition date, no lease evaluation is required unless the agreement is modified or acquired in a business combination, as summarized in Figure 2-8.

Modifications include any change in the contractual terms. Factors to consider in determining the impact of changes to contractual terms of grandfathered agreements are consistent with the factors to consider in reassessing contracts that contain leases.

Figure 2-8
Grandfathered contracts—reassessment considerations

Reassessment trigger	Considerations
Modification of terms	<ul style="list-style-type: none"> □ Evaluation of whether the contract meets the definition of a lease, as well as determination of lease classification, is performed as of the date of modification, considering the modified terms. □ Any change in terms, including an extension of an existing agreement, triggers the requirement to perform a lease assessment. □ Exercise of a renewal option in an existing lease would not require assessment, unless the parties modify or negotiate any of the terms of the renewal.
Business combination	<ul style="list-style-type: none"> □ Evaluation of whether the contract meets the definition of a lease, as well as determination of lease classification, is performed as of the original contract date (or last modification date if previously modified and classification had changed). See UP 8.3.2 for further information.

Absent a modification or business combination, grandfathered contracts should continue to follow the accounting model applied prior to the adoption date of EITF 01-8.

Question 2-18

Does an extension or renewal of a grandfathered arrangement trigger a reassessment?

PwC response

It depends. We believe that exercise of a renewal option that existed in the original arrangement with no change in the terms does not result in a modification of the arrangement and no assessment is required under ASC 840-10-35-2. However, if the parties negotiate any terms that change the original contract (e.g., a renewal or an extension) the contract would no longer be grandfathered and the reporting entity would need to evaluate whether the arrangement contains a lease. A renewal or extension may also trigger a modification reassessment if the arrangement was being accounted for as a lease prior to the modification.

2.4.2 Changes in contractual terms

In accordance with ASC 840, a reporting entity should reassess whether an arrangement contains a lease if there is a change in the contractual terms.

ASC 840-10-35-2(a)

Change in contractual terms. The arrangement shall be reassessed if the contractual arrangement among the parties involved changes, unless the change only renews or extends the arrangement.

Modifications to an arrangement may include, but are not limited to, changing the pricing provisions, moving to fixed rental payments from contingent rents (representing a change in minimum lease payments), changing the timing of payments, or shortening or lengthening the term of the contract. Any agreement to amend the terms of the contract (other than exercise of a renewal or extension included in the original agreement with no modifications), would trigger a reassessment.

Question 2-19

Is reassessment of an arrangement required if the change in terms is operational, not financial?

PwC response

It depends. The parties to an arrangement may agree to certain modifications as a result of operational needs or due to changes in Federal Energy Regulatory Commission (FERC), North American Electric Reliability Corporation (NERC), or local regulations that impact contract operating protocols. ASC 840 requires reassessment of an arrangement as a result of any change in contractual terms. However, in general, we believe that the presumption that a reassessment should be performed may be overcome if the agreed-upon changes have no impact on the contract economics or rights of the parties. This determination may require judgment, and should include consideration of factors such as:

- The reason for the change
- The level of management involved in approval (executive management or board approval suggests a more substantive change)
- The impact on the contractual cash flows (a significant change in cash flows is indicative of an economic effect that should be assessed)
- The impact on production (a change in the amount or timing of generation also suggests an economic impact)

For example, an agreement by the off-taker to pay for emissions credits required due to new environmental legislation would have an impact on the cash flows under the arrangement and would require a reassessment. In contrast, we believe that reassessment may not be required if the delivery point established in the agreement is changed to another location due to operational changes implemented by the applicable regional transmission organization. In evaluating whether there is an economic impact from a change in delivery location, factors to consider include the

impact on the off-taker's costs (e.g., whether there are new transmission costs, a different market price for potential resale, or new hedging costs). In many cases, an operational change results in some change to the pricing under the arrangement, which would trigger a reassessment.

Question 2-20

Is reassessment of an arrangement required if a price modification occurs as a result of a regulatory or other change imposed by a party external to the contract?

PwC response

It depends. At times, contractual terms in a power purchase agreement may change due to an action of a regulator or other third party. For example, the pricing in a contract may be linked to a formula established or approved by a regulator (qualifying facilities contracts are often based on the utility's avoided cost of production). A change in the formula by the regulator, whether through its own action or in response to a request from one or more parties to the arrangement, would represent a change to the contract terms, triggering a reassessment. Although this change may not be directly executed between the counterparties, the linkage of pricing to an external factor would represent an "informal" modification.

Note that a change in the pricing formula to be used is different from a change in the pricing as a result of new inputs to an agreed-upon methodology. A contract that specifies annual or other price updates based on a specified formula would not require reassessment, unless there were other contractual changes.

Question 2-21

Is reassessment of an arrangement required if a modification is subject to regulatory or other third-party approval?

PwC response

Generally, yes. Typically, when a regulated utility is considering entering into a significant contract, or substantively modifying a power purchase agreement, approval by its regulator is required. Careful consideration should be made by a reporting entity in these circumstances. Although the parties to the contract may negotiate and sign a modification, the modification may be contingent on regulatory approval. Even if a contract is silent on the matter, the utility's regulator or the interveners may have the opportunity to review, reject, or require changes to a power purchase agreement or related modifications. Approval by a regulator does not relieve the regulated utility from performing the reassessment. However, the reassessment date may occur after the modification is signed (e.g., the date the regulator approves the contract or modification) if a regulator is involved.

2.4.3 Contract renewals or extensions

A reporting entity is also required to assess whether a contract contains a lease and how the lease is classified if the parties agree to a renewal or extension.

ASC 840-10-35-2(b)

Renewal or extension. A renewal or extension of the arrangement that does not include modification of any of the terms in the original arrangement before the end of the term of the original arrangement shall be evaluated only with respect to the renewal or extension period. The accounting for the remaining term of the original arrangement shall continue without modification. The exercise of a renewal option that was included in the lease term at the inception of the arrangement shall not be considered a renewal for the purpose of reevaluating the arrangement. Accordingly, the exercise of the renewal option shall not trigger a reassessment.

A reassessment is required if the renewal or extension requires agreement between the parties or otherwise involves terms that were not specified in the original agreement. See ARM 4650.13 for further discussion on the accounting for lease renewals and extensions, including the impact on lease classification.

2.4.4 Arrangement is no longer dependent on the identified property

A reassessment is also triggered if fulfillment of the arrangement is no longer dependent on identified property, plant, or equipment, as further explained in ASC 840-10-55-36.

Excerpt from ASC 840-10-55-36

If an arrangement was initially determined to include a lease because, in part, fulfillment of the arrangement was initially dependent upon specific property, plant, or equipment and an event or events occurred after the inception of the arrangement such that fulfillment was no longer dependent upon the specific property, plant, or equipment (for example, an active market for the product develops after inception of the arrangement), the arrangement would be reassessed to determine if the arrangement contains a lease as of the date that the arrangement is no longer dependent upon specific property, plant, or equipment.

In most cases, a power purchase agreement is deemed to contain a lease because, among other reasons, it requires delivery from an identified power facility. However, there are circumstances where the property is implicitly identified, either because there is only one facility that is economically feasible to use, or replacement power is permitted but there are no available market sources or other alternatives.

In accordance with ASC 840-10-35-2(c), reassessment of these arrangements is required if there is a market or other change such that fulfillment is no longer dependent on the identified property.

2.4.5 Physical change to the plant

Another factor that requires a reassessment of whether an arrangement contains a lease is a physical change to the property identified in the arrangement.

ASC 840-10-35-2(d)

Physical change to specific property, plant, or equipment. A substantial physical change to the specified property, plant, or equipment requires a reassessment of the arrangement to determine whether the arrangement contains a lease on a prospective basis. For purposes of determining if a physical change to the specified property, plant, or equipment gives rise to a reassessment, increases or decreases in productive capacity that result from adding or subtracting a physically distinct unit of property, plant, or equipment shall be ignored if fulfillment of the arrangement is dependent upon a distinct unit of property, plant, or equipment that remains unchanged.

Physical changes to the identified property may include the building of another unit or a modification to the property such that the output of the existing units is changed. A reassessment will be triggered only if the physical changes directly impact the property identified in the arrangement. As such, if the contract involves a specified unit, expansion of that unit would result in a reassessment while the addition of a new unit would not. If no unit is specified, any physical change to the capacity of the facility would result in a reassessment. Both parties to the arrangement should assess physical changes to the identified property to determine if a reassessment is required.

2.4.5.1 Application example—reassessment

Simplified Example 2-12 illustrates a reassessment triggered due to a change in plant capacity.

EXAMPLE 2-12**Reassessment of a power purchase agreement due to an increase in plant capacity**

Rosemary Electric & Gas Company (REG) and Ivy Power Producers (IPP) have entered into a 20-year power purchase agreement whereby IPP will deliver all of the power and renewable energy credits from the Wisteria Wind Power Project, a 40 MW electric generating facility consisting of 20 interconnected wind-powered units. IPP has permits to build another 10 turbines on the same site. The pricing under the arrangement escalates annually by the Consumer Price Index. REG has no requirement to take the additional power and IPP may contract with a third party if the additional turbines are installed. At inception of the arrangement, both parties conclude that the power purchase agreement contains a lease, because REG will take all of the output and the pricing is neither fixed per unit nor at market per unit at the time of delivery of the output.

Five years into the term of the arrangement, IPP installs 10 additional turbines and enters into a separate arrangement with a different counterparty for the sale of the increased capacity. As a result, REG's portion of the output from the Wisteria project declines to approximately 67 percent of the total output. There is only one qualified metering and interconnection point for all of the units, and the REG contract does not specify particular turbines. Output from each turbine is fungible and not specifically identified to a particular buyer, instead each buyer will purchase a percentage of the

total output from the facility. As a result, the plant is deemed to be a single unit of account.

Does the addition of the 10 turbines trigger result in a reassessment of the existence of a lease in the arrangement?

Analysis

Upon the completion of the installation of the additional capacity, REG and IPP should reassess the arrangement in accordance with ASC 840-10-35-2(d). Assuming none of the other conditions in ASC 840-10-15-6 are met, REG and IPP would conclude that their arrangement no longer contains a lease because another party is taking more than a minor amount of the output. The parties should further assess whether the contract is a derivative or if executory contract accounting should be applied.

This conclusion is based on the specifics of the arrangement, primarily the fact that REG is taking a percentage of the output of all 30 turbines, not output from 20 specified turbines. If the turbines supplying REG were specified in the power purchase agreement and separately metered, the construction of the additional 10 turbines would not have triggered a reassessment.

2.5 Lease classification

Once a reporting entity determines that an arrangement contains a lease and it identifies and allocates the consideration between lease and nonlease elements, it needs to assess the appropriate lease classification. This section focuses on key considerations for classification of a lease by both the lessee and the lessor.

2.5.1 Lease characteristics affecting classification

Prior to determining lease classification, there are certain key characteristics of a lease arrangement that need to be considered by both the lessee and lessor. The key inputs into the classification analysis are:

- *Lease inception*

The lease inception date is the date that should be used when evaluating information (e.g., discount rate for purposes of calculating the present value of minimum lease payments, the fair value of the property) necessary to determine lease classification.

- *Integral equipment*

Power purchase agreements often involve a lease of integral equipment. Whether a lease involves integral equipment will impact lease classification for the lessor and potentially for the lessee.

- *Construction of assets to be leased (often referred to as build-to-suit arrangements)*

These arrangements involve the tailoring and construction of a facility to meet the off-taker's needs. A lessee that has involvement during the construction period may be deemed to be the owner of the facility during construction. In such cases, the lessee would need to capitalize the asset, including amounts funded by the lessor. Once construction is completed, the arrangement would be evaluated as a sale-leaseback transaction.

Each of these characteristics is further discussed in this section.

2.5.1.1 Lease inception

Identifying the lease inception date is important because it is on that date the lease classification is determined. The lease inception date is also the date on which the value of the lease asset and obligation are calculated. Lease inception is defined in ASC 840.

Definition from ASC 840-10-20

Lease Inception: The date of the lease agreement or commitment, if earlier. For purposes of this definition, a commitment shall be in writing, signed by the parties in interest to the transaction, and shall specifically set forth the principal provisions of the transaction. If any of the principal provisions are yet to be negotiated, such a preliminary agreement or commitment does not qualify for purposes of this definition.

Determining the lease inception date may be straightforward and will often coincide with the signing of the lease. However, many power purchase agreements that contain a lease have provisions requiring regulatory or other approvals or may involve contingencies because the referenced plant has not yet achieved commercial operation. These factors can make it difficult to determine the lease inception date.

In determining the lease inception date, it is necessary to consider whether there are any significant uncertainties surrounding operational, pricing, or other specific provisions that are likely to cause the parties to modify the agreement, and whether cancellation of the contract is permitted without further obligation. For example, if the contract is subject to approval by the regulator, which may result in changes to pricing or other significant terms, and the parties can choose to cancel the contract without further obligation, the lease inception date will not occur until all terms are finalized and the necessary approvals are received.

In addition, penalty payments (e.g., liquidating damages) or events of default triggered by a failure to achieve the commercial operation date (COD) should be considered in evaluating the date at which all of the principal provisions are negotiated.

Application example—lease inception date

Simplified Example 2-13 provides an illustration of determining the lease inception date.

EXAMPLE 2-13

Determination of the lease inception date

Ivy Power Producers is commencing construction of the Camellia Generating Station, a 575 MW natural gas-fired power plant. On January 1, 20X2, IPP signs a 30-year power purchase agreement with Rosemary Electric & Gas Company. The contract specifies a commercial operation date of January 1, 20X5, at which time payments under the contract will commence. All key provisions (e.g., operating protocols, pricing, and timing) are specified in the agreement, including a stipulation that if REG's regulator does not approve the contract for recovery in rates, it may be cancelled by either party without penalty. REG has evaluated the arrangement and concluded that it contains a lease.

Analysis

The regulatory approval process is not perfunctory and could result in a requirement for the parties to renegotiate the terms. This approval is a significant contingency that would need to be resolved before establishing a lease inception date. As a result, the lease inception date is not established until approval is obtained. If regulatory approval occurs on June 1, 20X3, for example, the lease inception date would be that date. This is the date the parties would use for performing all necessary evaluations and calculations to determine lease classification.

2.5.1.2 Integral equipment

Whether the leased asset is equipment or real estate (including integral equipment) can affect lease classification for the lessor. Depending on the type of facility, a lease arising out of a power purchase agreement often involves integral equipment. Integral equipment is defined in the Codification.

Definition from Master Glossary

Integral Equipment: Integral equipment is any physical structure or equipment attached to the real estate that cannot be removed and used separately without incurring significant cost.

In addition, ASC 360, *Property, Plant, and Equipment* (ASC 360), provides guidance that integral equipment should be considered real estate for purposes of evaluating sales of real estate. Most power plants meet the definition of integral equipment because they are attached to real estate (land or potentially buildings) and are generally costly to remove due to their size and nature. Further judgment may be needed when considering nontraditional power plant assets, such as rooftop solar panels or fuel cells. In such cases, in assessing whether an asset is integral equipment,

a reporting entity should evaluate whether the costs to remove the asset(s) from the land or buildings would be significant.

The evaluation of significant cost includes consideration of the cost of removal and the cost to repair any damage to the asset resulting from its removal. In addition, the cost includes any decrease in value of the asset as a result of the removal. Guidance on determining the decrease in value is provided in ASC 360-20-15-5.

Excerpt from ASC 360-20-15-5

At a minimum, the decrease in the value of the equipment as a result of its removal is the estimated cost to ship and reinstall the equipment at a new site.

ASC 360-20-15-7 provides guidance on determining whether the cost to remove the asset is significant.

ASC 360-20-15-7

When the combined total of both the cost to remove plus the decrease in value (for leasing transactions, the information used to estimate those costs and the decrease in value shall be as of lease inception) exceeds 10 percent of the fair value of the equipment (installed) (for leasing transactions, at lease inception), the equipment is integral equipment.

Any conclusions about whether the leased asset is integral equipment should be revisited by the reporting entity at the date of any future renewal or extension of a lease. Although an asset may not be considered integral equipment at lease inception, it may become integral equipment with the passage of time and would need to be reassessed at a renewal or extension date.

In addition to power plants, the concept of integral equipment also applies to other capital assets, such as transmission towers and natural gas pipelines. Whether a lease contains integral equipment is important for a lessor's evaluation of lease classification (see UP 2.5.3). Lessees of integral equipment may also be affected if the lease involves land and a building or a sale-leaseback transaction. See ARM 4650.4 for further information.

2.5.1.3 Build-to-suit arrangements

It is common for utilities and power companies to enter into power purchase agreements that contain a lease, prior to construction of the identified plant. In such arrangements, the project owner builds and configures the power plant based on the customer's specific requirements. Such arrangements are known as "build-to-suit" arrangements. However, all lease arrangements involving construction of the asset subject to lease need to be carefully considered by the lessee. Depending on the facts and circumstances, a reporting entity/lessee could potentially be deemed to be the owner of an asset if it has the option or obligation to lease the asset following its

construction. That may be the case if the reporting entity has substantially all the construction period risks.

ASC 840-40-15-5

A lessee shall be considered the owner of an asset during the construction period, and thus subject to this Subtopic, if the lessee has substantially all of the construction period risks—effectively a sale and leaseback of the asset occurs when construction of the asset is complete and the lease term begins (see the implementation guidance beginning in paragraph 840-40-55-2).

There are potentially significant financial statement impacts for the lessee if it is deemed to be the owner during construction of the power plant. Specifically, if the lessee is deemed to be the owner during construction, it should capitalize the construction costs and record a liability (whether construction is financed by the lessor or lessee). The lessee would also record ground lease rentals, assuming it does not own the land on which the power plant is being constructed. Once construction is complete and the lease commences, the arrangement would need to be evaluated as a sale and leaseback of real estate. Derecognition of the real estate would be permitted only when all prohibited continuing involvement has ceased. Given that the criteria for evaluating build-to-suit arrangements are complicated, reporting entities should carefully evaluate all leases involving assets to be constructed.

See ARM 4650.25 for information on evaluating whether the build-to-suit guidance is applicable.

2.5.2 Considerations for lessees

ASC 840-10-25-1 sets out four primary criteria to evaluate for classifying lease arrangements. Additional interpretative guidance also may be applicable when evaluating these criteria. If a lessee determines that any one of the following four criteria is met at lease inception, it will record a capital lease:

- Ownership of the asset under lease is transferred to the lessee by the end of the lease term.
- The lease contains a bargain purchase option.
- The lease term is at least 75 percent of the property’s estimated economic life (the “75 percent test”).
- The present value of the minimum lease payments at the beginning of the lease term is at least 90 percent or more of the fair value of the leased property (the “90 percent test”).

The 75 percent test and 90 percent test are not evaluated if the commencement of the lease term falls within the last 25 percent of the total estimated economic life of the leased asset.

Evaluating the classification of a lease contained in a power purchase agreement can be challenging. Determining whether ownership of the plant transfers to the purchaser (lessee) by the end of the lease term or whether there is a bargain purchase option is generally straightforward (see ARM 4650.1231 for further information on these tests, including discussion of purchase option pricing and economic penalties). However, power purchase agreements often contain terms that can make evaluating the 75 and 90 percent tests complex, as further discussed in the following sections. See UP 2.5.3 for lessor considerations.

2.5.2.1 The “75 percent test”

The 75 percent test considers the length of the lease as compared with the estimated economic life of the asset.

ASC 840-10-25-1(c)

Lease term. The lease term is equal to 75 percent or more of the estimated economic life of the leased property. However, if the beginning of the lease term falls within the last 25 percent of the total estimated economic life of the leased property, including earlier years of use, this criterion shall not be used for purposes of classifying the lease.

In evaluating a lease of a power facility, typically, the key judgment in performing the 75 percent test is the determination of the estimated economic life of the asset, which is discussed in this section. See ARM 4650.1241 for further information in general on performing the 75 percent test.

Estimated economic life of the asset

Application of the 75 percent test in practice for a power purchase agreement may be challenging because of the subjective nature of “estimated economic life.”

Definition from ASC 840-10-20

Estimated Economic Life: The estimated remaining period during which the property is expected to be economically usable by one or more users, with normal repairs and maintenance, for the purpose for which it was intended at lease inception, without limitation by the lease term.

The definition indicates that the period of economic use relates only to use for the purpose for which the property was intended at the inception of the lease. Furthermore, it is to be determined without limitation by the lease term. The estimated economic life of a leased asset is determined at the lease inception date based on known conditions. Therefore, a lease’s classification is not reevaluated if the economic life later changes (e.g., due to an impairment resulting from an impending shut down or an updated engineering study). However, any changes in the economic life may change the lease classification conclusion if a lease is later required to be reassessed for a modification.

In general, the intended use of a power plant does not change over the course of its life; therefore, there is limited interpretation on that aspect of the definition. Nonetheless, reporting entities should carefully consider the reasonableness of their estimation of the economic life of the power plant. Historically, reporting entities have used industry standard economic lives for assets such as coal, oil, and natural gas plants based on experience with the actual useful life of the assets. However, there is less historical experience for newer technologies, such as wind turbines and solar panels, which will require greater reliance on engineering estimates.

When determining the estimated economic life of a power plant, the depreciable life should also be considered. Depreciation is the allocation of cost over the estimated useful life of an asset. The useful life and economic life of a power plant are considered similar and therefore depreciable lives, which are based on useful lives, may be a sound basis on which to estimate economic lives for comparable assets. Accordingly, estimated economic lives established for the application of the guidance in ASC 840 generally should be consistent with asset lives established for depreciation purposes. In addition, other factors, such as turbine manufacturer warranties, major maintenance schedules, and asset retirement obligations, should be considered in the analysis to ensure consistent conclusions are being reached.

Question 2-22

What are the common useful lives for power plant assets?

PwC response

There is no one-size-fits-all useful life for power plants. The life will depend on many factors, including the type of plant, the specific technology used, historical and projected plant run profiles, and specific capital expenditure and maintenance programs. For example, there are many coal and natural gas power plants operating in the United States that are greater than 50 years old, while many hydro power plants are 100+ years old. Natural gas-fired plants are typically assumed to have a 30- to 40-year life. Alternatively, renewable and clean energy sources, due to their reliance on more recent technology, tend to have somewhat shorter estimated useful lives. For example, solar facilities may be estimated to last 25 to 30 years; however, they may require replacement earlier depending on the type of system and technology. Similarly, the estimated useful lives of wind facilities tend to be 25 to 30 years, but the actual life depends on a number of variables, including wind speed and variability in usage.

When estimating the useful life of power plants, it is also common practice to consider the “load” at which the plant normally operates. Base load plants, which run continuously, may have longer lives due to less variability in usage. Conversely, peaking plants are required to be ramped up quickly to meet short-term demands, often resulting in shorter lives due to intermittent use causing more stress and wear. However, all facts and circumstances need to be evaluated, including historical and projected market conditions, and there should be close coordination with the reporting entity’s plant engineers and consideration of the depreciable life.

2.5.2.2 *The “90 percent test”*

The 90 percent test considers the present value of the future minimum lease payments as compared with the fair value of the plant at lease inception.

ASC 840-10-25-1(d)

Minimum lease payments. The present value at the beginning of the lease term of the minimum lease payments, excluding that portion of the payments representing executory costs such as insurance, maintenance, and taxes to be paid by the lessor, including any profit thereon, equals or exceeds 90 percent of the excess of the fair value of the leased property to the lessor at lease inception over any related investment tax credit retained by the lessor and expected to be realized by the lessor. If the beginning of the lease term falls within the last 25 percent of the total estimated economic life of the leased property, including earlier years of use, this criterion shall not be used for purposes of classifying the lease.

Key considerations in performing the 90 percent test when evaluating leases of power plants include the impact (1) of contingent rentals on minimum lease payments and (2) on the fair value of the property at inception of the lease of any power plant-related government incentives received. These concepts are discussed in this section. See ARM 4650.1242 for further information in general in performing the 90 percent test.

Question 2-23

How do default provisions included in a power purchase agreement impact the calculation of minimum lease payments?

PwC response

It depends. Lease arrangements may include default covenants that are unrelated to the lessee’s use of the property (for example, the plant off-taker may be required to maintain certain financial ratios as a condition of the arrangement). The lessee may be required to pay default penalties in the event of noncompliance with these provisions. As a result, a question arises as to whether potential amounts to be paid in the event of noncompliance should be included in the minimum lease payments for purposes of determining lease classification.

The guidance on default covenants is included in ASC 840-10-25-14, which indicates that lease classification is not affected if all of the following conditions exist:

- The default covenant provision is customary
- The occurrence of the event of default is objectively determinable
- There are predefined criteria related only to the lessee to be used to determine whether there is an event of default

- It is reasonable to assume that default will not occur based on facts and circumstances existing at lease inception

However, if any of these conditions are not met, then the minimum lease payments used for purposes of lease classification should include the maximum amount that the lessee could be required to pay. The evaluation of these conditions requires judgment; see ARM 4650.1242 for further information.

Minimum lease payments—contingent rent

Minimum lease payments represent amounts that the lessee will pay, or could be required to pay, in connection with the leased asset. However, certain payments that are contingent on future use of the asset are not included in minimum lease payments, as described in ASC 840-10-25-4.

Excerpt from ASC 840-10-25-4

Lease payments that depend on a factor directly related to the future use of the leased property, such as machine hours of use or sales volume during the lease term, are contingent rentals and, accordingly, are excluded from minimum lease payments in their entirety.

Contingent rentals are future lease payments that are based on factors, trigger events, or specified targets (e.g., production, sales, or some other variable including changes in the consumer price index) that are outside the control of the lessor. The concept of contingent rentals contemplates that the lessor does not have the ability to effectively control the amount of rentals that it can require the lessee to pay in the future, and, as such, contingent rentals do not represent a present obligation for the lessee to make payments in connection with the leased property. Contingent rentals are defined in ASC 840.

Definition from ASC 840-10-20

Contingent Rentals: The increases or decreases in lease payments that result from changes occurring after lease inception in the factors (other than the passage of time) on which lease payments are based, excluding any escalation of minimum lease payments relating to increases in construction or acquisition cost of the leased property or for increases in some measure of cost or value during the construction or pre-construction period. The term *contingent rentals* contemplates an uncertainty about future changes in the factors on which lease payments are based.

In some cases, a power purchase agreement is structured such that the off-taker is responsible for dispatch; it will pay a fixed capacity charge and a separate charge for any energy delivered. In those circumstances, unless the contract specifies a minimum amount, all of the payments based on energy would be contingent because the lessor cannot require the off-taker to take any amounts.

The evaluation of contingent rentals becomes more complex in assessing must-take arrangements where the lessee is required to take any power produced from the facility as discussed in Questions 2-24 and 2-25.

Power purchase agreements that contain a lease, but include only contingent payments, generally result in operating lease classification because there are no minimum lease payments required (assuming the other criteria for capital lease classification are not met). When accounting for a power purchase agreement as an operating lease, contingent rental expense should be measured and recognized at the time the payments become probable, as required by ASC 840-10-25-35. If an arrangement meets the criteria for capital lease classification (e.g., because the lease term is greater than 75 percent of the asset's economic useful life), but all lease payments are contingent, there would be no obligation or related asset to recognize as there are no minimum lease payments. In these circumstances, it may be appropriate to classify the payments made by the lessee as an operating expense. Recording the payments as interest expense may not be appropriate because of a lack of a financing obligation recorded on the balance sheet. Presentation as an operating expense would only be appropriate for capital lease arrangements that have no minimum lease payments. See ARM 4650.1242 for further information on contingent rents.

Question 2-24

Does a minimum performance guarantee in a must-take power arrangement that contains a lease result in some level of minimum lease payments?

PwC response

It depends. In general, if an arrangement requires the off-taker to take all of the output, and provides penalties for failure by the lessor to achieve a certain minimum production level, there is likely some level of minimum lease payments.

ASC 840-10-25-5 discusses the definition of minimum lease payments from the perspective of the lessee.

Excerpt from ASC 840-10-25-5

For a lessee, minimum lease payments comprise the payments that the lessee is obligated to make or can be required to make in connection with the leased property, excluding both of the following:

- a. Contingent rentals
- b. Any guarantee by the lessee of the lessor's debt and the lessee's obligation to pay (apart from the rental payments) executory costs such as insurance, maintenance, and taxes in connection with the leased property.

Contingent rentals include amounts that are outside the control of both parties to a contract (e.g., future inflation rates) or that are solely in the lessee's control (e.g., lessee has the ability to dispatch a facility). Because of the associated uncertainty,

these amounts do not represent amounts that a lessee “is obligated to make or can be required to make.” In contrast, if the operations and dispatch of a facility are controlled by the lessor and the contract requires the lessee to take all of the power produced, and the fuel source is also within the control of the lessor (e.g., a natural gas plant or a coal plant), the lessor effectively controls whether the lessee will be required to make certain payments. Although the payments are based on future production from the facility, the level of production is in the control of the lessor and, thus, these amounts are not consistent with the definition of contingent rentals. Therefore, we generally expect that the amounts up to the guaranteed level of production should be used in the determination of minimum lease payments, except as discussed below with respect to certain renewable facilities.

Some renewable facilities are subject to production variability associated with a fuel source that is outside the control of the parties to the agreement (e.g., wind, solar). As a result, the output levels are inherently uncertain because production is dependent on weather or geological conditions. In such cases, the lessor cannot ultimately control whether the lessee will be required to make certain payments (as the facility’s operation depends on outside factors). Recognizing this inherent uncertainty, we believe that all production-based payments should be treated as contingent if the fuel source is outside the control of the parties to the arrangement. This would apply even if the lessor has provided a minimum production or performance guarantee.

In applying this view, reporting entities should assess the level of assurance and control associated with the fuel source. For example, wind, solar, and hydro facilities are dependent on a fuel that is wholly outside the control of the parties to the contract. In contrast, methane or geothermal facilities may be more similar to fossil fuel plants. Reporting entities should consider their specific facts and circumstances in determining the appropriate accounting. Furthermore, the interpretation of minimum lease payments should be disclosed, if material, and should be applied on a consistent basis (to instances of reasonably similar facts and circumstances).

Question 2-25

In a must-take power purchase agreement, is there always at least some expected amount of output that is “virtually assured” that should be considered a minimum lease payment?

PwC response

It depends. Arguably, if the facility relies on a fuel source that is within the control of one of the parties to the arrangement, there is likely to be some portion of production that is virtually assured. As discussed in our response to Question 2-24, we believe amounts up to any guaranteed level of production should be used in the determination of minimum lease payments. However, in assessing arrangements without minimum performance guarantees, there are different views on whether there is a level of production that is not contingent. Some believe that all amounts are contingent because they are dependent on the future operation of a power facility, even though production is within the control of one of the parties to the arrangement. Even if there are engineering and other studies to support a specified level of production, and if the

facility has reliably produced at a certain level in the past, there could be variations in the amount or timing of production (e.g., time of year or time of day).

Others hold a view that the facility would not have been constructed without sufficient support for a minimum level of production. The off-taker would not have entered into the agreement without some expectation that output would be produced.

Furthermore, parties involved in financing the entity would not have provided support without an expectation of future cash flows. Therefore, supporters of this view believe that there is always a level of production that is virtually assured; they acknowledge that determining the appropriate level requires judgment.

In assessing arrangements involving facilities dependent on a fuel source within the control of one of the parties to the arrangement, we believe that both views have merit when assessing amounts in excess of the guaranteed minimum. Thus, a reporting entity may conclude in such cases that rents related to production above a contractually guaranteed minimum are either all contingent or that there are minimum lease payments. Minimum lease payments based on production above a contractually guaranteed minimum level should be supported with appropriate evidence. For example, payments under a power purchase agreement for a fossil fuel plant may be contingent on future production. Nonetheless, facts and circumstances may suggest that at least a certain amount of power will be produced based on the usage of the plant (e.g., it is a base load plant), historical experience, and the stability of the technology such that it would be reasonable to estimate a corresponding level of minimum lease payments.

However, in evaluating renewable facilities where the fuel source is outside the control of the parties to the arrangement, there is inherent uncertainty about future production. Therefore, in such cases, we believe that all rentals dependent on production from such plants are contingent. See Question 2-24 for further information.

Question 2-26

In a tolling or other arrangement where the lessee has volumetric optionality and there are no minimum performance penalties, can output that is virtually assured be considered a minimum lease payment?

PwC response

No. As discussed in the excerpt from ASC 840-10-25-5 above, minimum lease payments represent the amount that the lessee is required to pay or could be required to pay in connection with the leased asset. In contrast, contingent rentals include amounts that are outside the effective control of both parties to a contract or that are solely in the lessee's control. In an arrangement where the lessee determines the level of production, all amounts are contingent as the lessee could choose not to dispatch at any point (assuming that there is no minimum guarantee of off-take). This is consistent with the example in ASC 840-10-55-38, which discusses rentals based on future sales from a retail store.

Note that this conclusion differs from the accounting for a must-take arrangement (discussed in the response to Question 2-25) because of the difference in which party has control of the amount of output from the facility. In a must-take arrangement, the lessor can force the lessee to take all of the output produced and thus payments based on production could be considered minimum lease payments under one of the two views described. In a tolling or option contract, the lessor has no control of the amount dispatched and thus all amounts are contingent.

Impact of government incentives on the fair value of the leased asset at inception

The owners of renewable energy plants often obtain government incentives that may include Section 1603 grants, investment tax credits (ITC), or production tax credits (PTC). Section 1603 grants provide grantees with the choice of applying for and receiving a government grant in lieu of investment tax credits. See UP 16 for further information about Section 1603 grants.

Investment tax credits have an impact on the calculation of the fair value of the lease asset for purposes of the 90 percent test, as discussed in ASC 840-10-25-1(d).

Excerpt from ASC 840-10-25-1(d)

The present value at the beginning of the lease term of the minimum lease payments, . . . equals or exceeds 90 percent of the excess of the fair value of the leased property to the lessor at lease inception over any related investment tax credit retained by the lessor and expected to be realized by the lessor.

Therefore, when evaluating lease classification, ASC 840 requires that the fair value of the leased property used as the denominator in calculating the 90 percent test be reduced by investment tax credits retained by the lessor. However, a question arises as to how to consider other forms of tax incentives, in particular Section 1603 government grants, which are similar to ITC.

Question 2-27

Should Section 1603 grants received by the lessor for the plant that is subject to the lease be deducted from the fair value of the plant in performing the 90 percent test?

PwC response

Yes. Section 1603 grants are provided as an alternative to investment tax credits and qualifying parties may elect to receive Section 1603 grants in lieu of ITC on qualifying properties. In such cases, a reporting entity should follow a grant accounting model for either the Section 1603 grant or ITC, unless there is an economic disincentive for taking the grant instead of ITC (see UP 16.3 for further information). Given this conclusion, and the fact that the Section 1603 grant results in an immediate cash payment from the government once approved, we believe that the Section 1603 grant should also be deducted from the fair value of the leased property when performing

the 90 percent test, provided the control with respect to the risk of recapture of the grant is retained by the lessor, and the lessor expects to realize the grant.

This guidance is specific to the Section 1603 grants and should not be analogized to for other grants or tax credits, including the production tax credit.

2.5.3 Considerations for lessors

Lessors are required to classify leases as sales-type, direct financing, leveraged, or operating. In addition to the four criteria described in UP 2.5.2, ASC 840-10-25-42 requires two additional criteria to be met for a lease to qualify as a sales-type lease or direct financing lease from the lessor's perspective:

- Collectibility of minimum lease payments is reasonably predictable (e.g., payment dependent upon receipt of government approval may not be reasonably predictable but typically estimates regarding collectibility for receivables do not indicate this criterion is not met).
- No important uncertainties surround the amount of unreimbursable costs yet to be incurred by the lessor under the lease.

See ARM 4650.3 for further information about lease classification by lessors, including evaluation of the above two criteria. This section discusses unique issues for lessors in the utility and power industry.

2.5.3.1 Integral equipment

Integral equipment refers to any physical structure or equipment attached to real estate that cannot be removed and used separately without incurring significant cost. Examples of integral equipment include an office building, a manufacturing facility, a power plant, a refinery, and, possibly, the machinery on those sites. Integral equipment is considered "real estate" and is subject to the scope of various real estate-related accounting standards.

ASC 360-20-15 provides that the determination of whether equipment is integral equipment should be based on the significance of the cost to remove the equipment from its existing location (including the cost of repairing damage) plus the decrease in value of the equipment as a result of the removal. The decrease in value cannot be less than the estimated cost to ship and reinstall the equipment at a new site. When the total of the cost to remove and the decrease in value (determined at the time of the transaction) exceeds 10 percent of the fair value of the equipment, the equipment is considered integral.

For utilities and power companies that lease power plants and other similar assets, the consideration of whether the lease involves integral equipment is critical to the analysis of lease classification. Figure 2-9 highlights the impact of these considerations when assessing lease classification.

Figure 2-9
Integral equipment—key considerations for lease classification by the lessor

Lease classification	Considerations
Sales-type	<ul style="list-style-type: none"> □ Ownership (title) of the leased property automatically transfers to the lessee by the end of the lease
Direct financing	<ul style="list-style-type: none"> □ Lease does not give rise to manufacturer's profit; i.e., fair value of the plant must be the same as its cost or carrying amount (if different from cost) □ Generally only applicable when the property to be leased is acquired by the lessor at or very shortly before the inception of the lease
Leveraged	<ul style="list-style-type: none"> □ Meets the definition of a direct financing lease, has an additional party involved (a long-term creditor), and meets certain other criteria
Operating	<ul style="list-style-type: none"> □ Applicable if none of the other classification categories are met

Lessors in the utility and power industry often classify leases of power plants as operating, because the property generally does not transfer title to the lessee at the end of the lease term and the carrying value and fair value of the plant differ at lease inception. As such, the leases do not qualify as sales-type or direct financing leases. Additionally, a power purchase agreement may include a performance guarantee, which may preclude sales-type lease classification as this type of guarantee represents a significant uncertainty associated with costs yet to be incurred by the lessor and, therefore, would not meet both of the required criteria in ASC 840-10-25-42.

ASC 840-10-55-46 discusses this concept as it applies to leveraged leases (one of the conditions for a lease to qualify as a leveraged lease is that it meets the criteria applicable to qualify as a direct financing lease).

Excerpt from ASC 840-10-55-46

Although the carrying amount (cost less accumulated depreciation) of an asset previously placed in service may not be significantly different from its fair value, the two amounts will not likely be the same. Therefore, leveraged lease accounting will not be appropriate, generally, other than when an asset to be leased is acquired by the lessor.

In general, we would not expect the carrying value of a plant to equal its fair value at lease inception unless the plant is acquired at the time of, or very shortly before, lease inception. Therefore, generally we would not expect direct financing lease treatment to be applicable to power plant leases.

Application example—lessor classification of a lease involving integral equipment

Example 2-14 considers the lessor classification criteria for a power plant that is integral equipment.

EXAMPLE 2-14

Lessor classification of a lease involving integral equipment

Ivy Power Producers is commencing construction of the Camellia Generating Station, a 575 MW natural gas-fired generating facility, to sell power under a 10-year power purchase agreement with Rosemary Electric & Gas Company. The facility is being built in contemplation of serving only REG based upon its needs over the course of the agreement. Therefore, all of the output from the facility will be supplied to REG for purposes of serving retail customers. IPP will retain ownership of the facility at the end of the term of the agreement and there are no renewal or bargain purchase options. IPP determines that the agreement contains a lease of integral equipment and is considering how the lease should be classified in its financial statements. For purposes of this example, assume that REG is not the accounting owner during construction (i.e., build-to-suit guidance is not applicable).

Analysis

IPP considers the different potential lease classification alternatives.

□ *Sales-type lease*

Because the lease involves integral equipment, it is evaluated as real estate for the purpose of classification. Accordingly, the only criteria applicable when determining whether a lease involving real estate is a sales-type lease is whether title transfers to the lessee. In this fact pattern, IPP retains ownership of the facility at the end of the lease term and, therefore, this lease would not qualify as a sales-type lease.

□ *Direct financing or leveraged lease*

Because the arrangement does not involve the financing by any other party, IPP concludes that an analysis as a leveraged lease is not necessary. In order for the lease to qualify as a direct financing lease, there should be no manufacturer's or dealer's profit (or loss) at lease inception (i.e., the cost (or carrying value if different) of the facility and fair value must be the same at lease inception). In addition, the arrangement should meet at least one of the criteria in ASC 840-10-25-1 and both of the criteria in ASC 840-10-25-42. In this fact pattern, the facility will be built to serve REG with developer's profit built into the price of construction. IPP has incurred costs of development and construction involves some risk such that its cost is not equivalent to fair value at lease inception. As a result, further analysis of ASC 840-10-25-1 and ASC 840-10-25-42 is not considered necessary; the lease will not qualify as a direct financing lease.

□ *Operating lease*

In this fact pattern, the lease should be classified as an operating lease because it does not qualify as either a sales-type or a direct financing lease. Therefore, IPP would continue to recognize the power plant as a long-term asset in property, plant, and equipment; and recognize depreciation expense and rental income over the life of the agreement.

In assessing this type of arrangement, a reporting entity should consider all facts and circumstances in determining the appropriate accounting.

Chapter 3: ***Derivatives and hedging***

3.1 Chapter overview

Utilities and power companies frequently use derivative contracts in managing their businesses. Despite the fact that ASC 815 has been in effect for over 15 years, reporting entities continue to face difficulty in application given the complexity of the guidance and continued evolution of commodity derivatives in the marketplace. Compounding these issues, utilities and power companies often apply derivative scope exceptions or hedge accounting to minimize the income statement volatility that arises from recognizing derivative instruments at fair value.

This chapter provides guidance on specific issues associated with commodity contracts commonly used by utilities and power companies. Topics discussed include:

- Evaluating whether a commodity contract meets the definition of a derivative
- Applying scope exceptions, including the normal purchases and normal sales scope exception specific to power contracts
- Determining when cash flow hedge accounting can be applied to forecasted purchase or sale transactions, along with maintaining ongoing compliance
- Matters to consider in accounting for specific types of commodity contracts

This chapter supplements the PwC *Derivative instruments and hedging activities* guide. It does not address all aspects of the guidance in ASC 815; rather, it focuses on derivative and hedging issues unique to the utility and power industry. See DH for additional information.

In addition, this chapter should be read in connection with UP 1, which discusses the overall evaluation framework applicable to commodity contracts. This chapter focuses on the derivative assessment, assuming the contracts discussed do not contain a lease. See UP 2 for information on evaluating whether a contract contains a lease.

3.2 Definition of a derivative

ASC 815-10-15-83 describes three criteria that all must be met for a commodity contract to qualify as a derivative instrument:

- There is an underlying, and one or more notional amounts and/or payment provisions
- There is little or no initial net investment
- Net settlement is permitted or required

The following sections highlight considerations in evaluating those criteria.

3.2.1 *Underlying, notional amount, payment provision*

In evaluating a contract to determine whether it is a derivative, the first criterion is that it has an underlying and a notional amount (or payment provision).

ASC 815-10-15-83(a)

Underlying, notional amount, payment provision. The contract has both of the following terms, which determine the amount of the settlement or settlements, and, in some cases, whether or not a settlement is required:

1. One or more underlyings
2. One or more notional amounts or payment provisions or both.

The underlying is generally clearly defined in a typical commodity contract: it is the price or rate of the specified commodity (e.g., \$/MWh, \$/MMBtu). ASC 815-10-55-77 through 55-83 provide additional guidance on the determination of the underlying in commodity contracts.¹ Consistent with this guidance, the underlying may be a fixed price, the market price at the time of delivery, or a price based on a contractual formula (e.g., the prevailing market index plus or minus a basis differential).

The notional is also explicitly stated in many natural gas or power contracts, and in such cases the underlying and notional evaluation is typically straightforward. However, commodity contracts may be designed to provide flexibility in meeting operating requirements or may be tailored to meet the needs of one of the parties to the agreement. As a result, the evaluation of whether a commodity contract has a notional amount is often one of the most challenging issues in determining whether a contract is a derivative. Common contracts that may require further evaluation include:

- Commodity contracts with volumetric optionality, including requirements contracts
- Contracts for the sale or purchase of capacity and/or power from a specified generating facility
- Power or capacity contracts with complex default provisions
- Other contracts with terms that provide some flexibility to the purchaser or seller or where a notional amount is not explicitly stated

Guidance on determining the notional amount of commodity contracts is addressed in ASC 815-10-55-5 through 55-7² and is further discussed in this section.

¹ Guidance originally issued as DIG Issue A11, *Definition of a Derivative: Determination of an Underlying When a Commodity Contract Includes a Fixed Element and a Variable Element*.

² Guidance originally issued as DIG Issue A6, *Definition of a Derivative: Notional Amounts of Commodity Contracts*.

3.2.1.1 Requirements contracts

Utilities and power companies often enter into requirements contracts for the supply or sale of power or natural gas. A requirements contract is defined in ASC 815-10-55-5 as a contract that requires one party to the contract to buy the quantity needed to satisfy its needs.

Excerpt from ASC 815-10-55-5(a)

As many units as required to satisfy its actual needs (that is, to be used or consumed) for the commodity during the period of the contract (a requirements contract). The party is not permitted to buy more than its actual needs (for example, the party cannot buy excess units for resale).

Although this type of contract is entered into to meet the needs of one of the parties to the contract, it may meet the definition of a derivative. A reporting entity will need to analyze the terms of the requirements contract to determine whether it is a derivative instrument; that determination depends in part on whether the contract contains a notional amount.

The requirements contract guidance in ASC 815-10-55-5 through 55-7 is only applicable in cases where the seller is to supply all of the purchaser's needs and where the purchaser "cannot buy excess units for resale." For example, this guidance would apply to the accounting for a requirements contract between a small irrigation district and its local investor-owned utility, whereby the utility procures power for the district. The utility supplies all of the power required by the irrigation district's retail customers; however, the quantity of power sold under the contract is limited to the level required to serve the irrigation district's retail load.

We believe that reporting entities should consider the requirements contract guidance in conjunction with the guidance on penalties for nonperformance or default in ASC 815-10-15-103.³ In a requirements contract, the contract has a notional amount only if the contract includes a reliable means to determine a quantity. Settlement or default provisions in the contract may provide that means. In evaluating whether this type of contract has a notional amount, reporting entities should consider:

- *Is there a specified minimum or maximum quantity?*

If the contract includes a specified minimum quantity, the notional amount will be at least equal to that amount. However, the notional may be larger than the minimum, depending on other contract provisions. If the contract specifies only a maximum quantity, the counterparties should evaluate the other contract provisions to determine whether there is a notional amount, because a maximum quantity alone would not create a notional. Any notional present would not be greater than the maximum amount specified. In all cases, the quantity

³ Guidance originally issued as DIG Issue A5, *Definition of a Derivative: Penalties for Nonperformance That Constitute Net Settlement*.

requirement should be enforceable through the default provisions or another mechanism in the contract.

- *Is there an explicit mechanism to calculate a determinable amount supporting the buyer's needs?*

Many requirements contracts include a specific methodology for determining the expected amount to meet the buyer's needs. For example, the contract may include a formula to calculate expected deliveries under the contract based on a three-year historical average. In addition, the contract's default provisions should be reviewed when considering whether these types of calculations are included, thus potentially creating a notional amount. If neither party has recourse against the other for failure to take or deliver the specified quantities, then the default provisions would not create a notional amount. See further discussion regarding default provisions below.

- *Does the contract have settlement or other default provisions that specify quantities?*

Consideration of the settlement and default provisions will often determine whether a commodity contract has a notional amount. In some cases, the default provisions specifically refer to anticipated quantities or specify a formula to use in the calculation of penalty amounts in the event of nonperformance. The default provisions need to be significant enough to force performance. If the penalty for default is minimal, the default provisions may not create a notional amount. The determination of whether a default provision is significant is judgmental and specific to the facts and circumstances considering the nature of the penalty, the amount in relation to the overall contract, and similar factors. See UP 3.2.1.4 for further information.

- *Does the contract include other forms of performance assurance that support calculation of a notional?*

Contracts may also include other forms of performance assurance, such as a requirement to post letters of credit or alternative forms of collateral (including parent guarantees), or to provide step-in rights if the seller fails to perform. Such contracts may include appendices or exhibits that provide quantity estimates that are used to determine the level of collateral or margining required. These types of performance requirements would generally create a notional amount under the contract if management determines (with the assistance of legal counsel if necessary) that the quantities specified are equivalent to default provisions within the contract. However, if such amounts would be considered as one factor in a default but are not determinative, in general, we do not believe that this would create a notional amount because there is no legally enforceable quantity. The key question is whether there is a quantity specified that can be enforced by either of the parties to the contract in the event of nonperformance. See Example 3-1.

In evaluating a requirements contract, there is no notional amount unless either the buyer or seller has the right or ability to enforce a quantity at a specified level, or if the seller is compelled to perform due to a material penalty provision. Provisions supporting

the notional amount should be included in the contract itself or a legally binding side agreement. Informal discussions between the counterparties, information provided only for scheduling purposes, and other similar support would not be sufficient to create a notional amount. See also UP 3.2.1.3 for further information about application of this guidance to plant-specific contracts.

Question 3-1

Does the fact that a commodity agreement includes a prohibition against resale mean that it is a requirements contract?

PwC response

Not necessarily. Although a resale prohibition may be indicative that the requirements contract guidance is applicable (as illustrated in ASC 815-10-55-5(b) below), this would not, on its own, be determinative that a contract is a requirements contract. Application of the requirements contract guidance often results in a different conclusion regarding the notional amount when compared to application of the general derivative guidance. In considering whether the requirements contract guidance applies, ASC 815-10-55-5(b) addresses contracts that are designed to meet the buyer's actual needs and that also prohibit resale.

Excerpt from ASC 815-10-55-5(b)

Only as many units as needed to satisfy its actual needs up to a maximum of 100 units. The party is not permitted to buy more than its actual needs (for example, the party cannot buy excess units for resale).

Therefore, in addition to a restriction on resale, there should also be evidence that the contract is designed to satisfy the buyer's needs in order to qualify as a requirements contract.

Question 3-2

In a requirements contract, does the presence of contractual provisions that acknowledge potential changes in a buyer's needs impact the determination of notional amount?

PwC response

Sometimes. Reporting entities procuring power under requirements contracts typically need some flexibility to adjust the contract quantity in response to changes in demand. Some contracts specify a minimum quantity and provide flexibility for additional amounts. Other contracts may incorporate default or other provisions based on average historical load over a specified period, with provisions for adjustments due to load shift or other factors.

ASC 815-10-55-7(a) acknowledges that the notional quantity may change over the life of a contract. In accordance with this guidance, there would be no notional if the

determination of the amount is highly subjective and unreliable. However, when a contract includes default or other provisions that specify a methodology for determining a notional amount, the contract contains a notional. Subsequent changes in factors impacting the calculation (e.g., load changes) would be incorporated by updating the notional amount and the calculation of the derivative's fair value as additional information is available.

Excerpt from ASC 815-10-55-7(a)

The determination of a requirements contract's notional amount must be performed over the life of the contract and could result in the fluctuation of the notional amount if, for instance, the default provisions reference a rolling cumulative average of historical usage. If the notional amount is not determinable, making the quantification of such an amount highly subjective and relatively unreliable (for example, if a contract does not contain settlement and default provisions that explicitly reference quantities or provide a formula based on historical usage), such contracts are considered not to contain a notional amount as that term is used in this Subtopic.

ASC 815-10-55-7(a) provides an example of a contract with default provisions that calculate penalty amounts in the event of nonperformance based on a rolling historical average. The notional will change over time; however, because the quantity is determinable at any point, it represents a notional amount that should be used in the assessment of whether the contract is a derivative instrument. The changes in the notional amount should be incorporated as they occur on a prospective basis. This is supported by the guidance in ASC 815-10-55-7(a).

See simplified Examples 3-1 through 3-4 for illustration of application of the guidance relating to the determination of whether a contract meets the characteristics of a requirements contract.

3.2.1.2 Capacity and other option contracts

The requirements contract guidance on notional amounts applies only where the quantity sold is based on the operational needs of one of the parties to the contract and neither the buyer nor the seller can enforce the quantity specified under the contract for profit (i.e., the buyer or seller cannot make purchase or sale decisions to profit from market changes). Most commodity contracts either specify a quantity or provide volumetric control to either the seller (a put option) or the buyer (a call option); in such cases, the requirements contract guidance on notional amounts would not apply. An option contract provides at least one of the parties with the ability to compel delivery and would not meet the criteria for application of the requirements contract guidance.

The primary difference between a requirements contract and an option contract is the limitation on the ability of the parties to control the quantity taken under a requirements contract. In an option contract, the buyer and seller will put or call the commodity based on the strike price and commodity market prices or operational needs. In contrast, in a requirements contract, the quantity is defined by the specified requirements of one of the parties to the agreement, thus volumes in excess of the

requirements cannot be purchased. Although the contract may be referred to as a capacity contract or a supply contract, any agreement that provides one party with the ability to profit from the flexibility to call or put a certain volume of a commodity at its option is highly likely to have a notional amount for the option's stated volume.

Question 3-3

How is the assessment of a notional amount affected if a contract is a capacity contract rather than an option contract?

PwC response

An agreement's classification as a capacity or an option contract has no bearing on the determination of notional amount. ASC 815-10-55-31 provides guidance for determining whether a power supply agreement is a capacity contract or an option contract. This guidance is applied to evaluate whether a contract qualifies for the power-specific normal purchases and normal sales scope exception. However, a conclusion that a contract is a capacity contract does not impact whether it has a notional amount.

In evaluating whether a contract has a notional amount, a reporting entity should assess all relevant contract terms, including settlement and default provisions to determine if a notional amount can be reliably determined. It should also assess whether the contract qualifies for the specialized guidance for requirements contracts.

Question 3-4

How should a reporting entity evaluate whether there is a notional amount when considering a hybrid instrument that includes both energy and capacity?

PwC response

In many tolling and similar agreements, the seller is required to provide a specified amount of capacity and the buyer can call an equivalent quantity of electric energy on an as-needed basis.

The evaluation of whether a tolling agreement is a derivative in its entirety or contains any embedded derivatives is discussed in UP 3.6.5. Focusing solely on the question of whether this type of contract has a notional amount, a question may arise as to the notional of the energy component. The default provisions in this type of contract often focus on plant availability and the specified amount of capacity, and may not include a separate penalty related to delivery of energy. However, because capacity represents the ability to generate energy, we believe that a sufficiently large penalty related to capacity will also create a notional amount of energy. The notional amount for the energy will be based on the required level of capacity, because the energy option can be exercised and energy can be produced if the plant is available. Therefore, the energy component would have a notional.

See UP 1 and UP 3.4 for further information on the clearly and closely related evaluation and other considerations related to embedded derivatives. See UP 3.2.1.4 for examples illustrating the determination of a notional amount for various types of contracts.

3.2.1.3 Plant-specific contracts

The determination of notional amounts also may be complex when evaluating contracts that explicitly specify a particular plant or other source of supply (plant-specific contracts). We believe the requirements contract guidance discussed in UP 3.2.1.1 may be applied by analogy to contracts where delivery is dependent upon the successful operation of a specified plant or system. This is based on the premise that the volumes under such contracts cannot be assured, absent a specific performance guarantee.

In evaluating contract terms and default provisions, reporting entities should consider the guidance provided by ASC 815-10-15-103. This paragraph addresses whether a contract has the characteristic of net settlement, not whether it has a notional amount. However, its discussion of performance penalties is helpful in assessing whether a contract has a notional amount.

Excerpt from ASC 815-10-15-103(c)

A contract that contains a variable penalty for nonperformance based on changes in the price of the items that are the subject of the contract does not contain a net settlement provision...if it also contains an incremental penalty of a fixed amount (or fixed amount per unit) that would be expected to be significant enough at all dates during the remaining term of the contract to make the possibility of nonperformance remote. If a contract includes such a provision, it effectively requires performance, that is, requires the party to deliver an asset that is associated with the underlying.

Nonperformance penalties, including certain make-whole contract provisions, sufficient to induce performance would typically result in a conclusion that a contract has a notional amount equal to the quantity used in the penalty calculation. In contrast, a contract that ties performance to the availability of a specified facility, with no penalty for nonperformance, has no notional amount and, as such, is not accounted for as a derivative.

The combination of specifying the plant and the lack of penalty for nonperformance leads to the conclusion that the contract does not have a notional amount. The lack of a nonperformance penalty alone would not lead to the conclusion that the contract has no notional amount in a contract where the quantity is specified and there is no explicit source of supply. In that case, the supplier would have no basis for nonperformance and the purchaser would have recourse under standard contract law if the supplier fails to deliver. This type of contract would have a notional calculated based on the quantity specified in the agreement.

Question 3-5

Does a unit-contingent contract for a plant under construction contain a notional amount?

PwC response

It depends. Utilities and power companies may enter into contracts for output from a specified power generating facility for which construction has not commenced or is still ongoing. In such cases, even if a quantity is specified in the contract, a question may arise as to whether the contract has a notional amount during the period between the signing of the contract and the commercial operation date.

In evaluating whether a plant-specific contract has a notional amount, the reporting entity should consider the contract terms and the enforceability of the contract.

Factors to consider in making this assessment include:

- Cancellation clauses related to permitting or other approvals—Does the contract automatically terminate if all required approvals are not received by a certain date?
- Penalties for nonperformance—Does the contract include provisions that penalize the seller if the plant is not completed by a specified date?
- Nature of the technology—Does the plant involve experimental technology or involve other factors that may increase construction risk and create greater uncertainty about achieving commercial operation?
- Certification of plant—If applicable in the specified market, has the regional transmission organization or other certifying party cleared the plant to be a qualified capacity resource?
- Other uncertainties—Are there other uncertainties associated with the construction that could impact the timing of contract commencement or quantities to be delivered?

Similar to the determination of a notional amount in other contracts, in evaluating the notional amount related to a plant under construction, the reporting entity should consider whether performance under the contract may be enforced. Therefore, cancellation clauses for various contingencies with no penalty to either party would lead to a conclusion that the contract does not have a reliable notional amount and should not be accounted for as a derivative. In contrast, contract provisions that result in significant penalties if the commercial operation date is not achieved would likely support a notional amount.

Reporting entities should consider the specific facts and circumstances in evaluating this type of contract. However, typically, we would not expect derivative accounting to commence until the plant has started commercial operation, unless the contract includes penalties for nonperformance that are sufficient to compel completion of construction of the plant by the specified date. In some cases, the determination of

whether a notional exists will change over the construction period as specific milestones are met and penalties for nonperformance change. The notional amount may also need to be reassessed at the commercial operation date. In addition, in evaluating this type of contract, reporting entities should consider the general guidance for plant-specific contracts and the determination of a notional amount.

3.2.1.4 Application examples—Requirements contracts

The following simplified examples are provided to illustrate the application of the guidance on requirements contracts and plant-specific contracts. The sample fact patterns have been included solely for the purpose of assessing whether the contracts have a notional amount in accordance with ASC 815.

EXAMPLE 3-1

Determination of notional amount — natural gas supply agreement with take-or-pay minimum and contract maximum

Ivy Power Producers (IPP) owns the Maple Generating Station, a 500 MW natural gas-fired power plant. IPP enters into a natural gas supply agreement with Guava Gas Company (GGC), a natural gas supply company. The parties to the agreement understand that the supply is for the operation of the Maple power plant. The contract has a maximum daily quantity (10,000 MMBtus per day). IPP is required to take or pay for a minimum amount representing at least 75% of the maximum daily quantity specified in the contract and may take additional amounts up to the maximum specified.

Does the arrangement qualify as a requirements contract?

Analysis

This contract is not a requirements contract as addressed in ASC 815-10-55-5 because it does not explicitly link the purchases to production at the plant nor does it prohibit the purchase of natural gas for resale. Rather, this is a combined forward and option contract that should be accounted for as a derivative if all of the other provisions in ASC 815 are met. Although IPP intends to use the natural gas for production at the Maple power plant, it could elect to take excess quantities for resale into the wholesale market (e.g., if the contract price is lower than the then-current market price). The conclusion would not change even if the parties to the contract had a mutual understanding that the contract was intended to supply generation at a particular plant. To qualify for the requirements contract guidance, restrictions on use of quantities provided and the prohibition on resale should be explicitly stated in the contract.

In this example, the contract represents a forward contract for 75% of the maximum daily quantity (7,500 MMBtus) and an option contract for the remaining 25% (2,500 MMBtus). See UP Example 3-18 for information on application of the normal purchases and normal sales scope exception to a contract with this fact pattern.

EXAMPLE 3-2

Determination of notional amount — natural gas supply agreement to supply all of the needs of a generating facility

Assume the same facts as in Example 3-1, except that the contract specifies that quantities provided are intended to supply all of Ivy Power Producer's natural gas needs for the Maple Generating Station. In addition, IPP is required to take at least 7,500 MMBtus/day and may take additional amounts up to 10,000 MMBtus/day. The agreement explicitly states that all purchases under the contract must be used for generation at the Maple power plant and that resale is prohibited.

Does the arrangement qualify as a requirements contract?

Analysis

Because quantities delivered under the agreement are limited to what can be used in the Maple power plant and no amounts can be resold, the quantity supplied is not fully in the control of either party to the contract (quantity may change due to unplanned outages, performance issues, or other factors). Therefore, the contract is a requirements contract that should be evaluated in accordance with the guidance provided by ASC 815-10-55-5 through 55-7.

IPP is required to take at least 7,500 MMBtus/day, even if the Maple power plant is shut down or it cannot otherwise use it for operations. Therefore, in accordance with the requirements contract guidance, this contract represents a forward contract for the minimum amount that IPP is required to take under the contract terms (7,500 MMBtus/day). There is no derivative accounting for the additional "option" component. In this example, the notional amount is equal to the minimum quantity IPP is required to take (7,500 MMBtus). See Example 3-19 for information on application of the normal purchases and normal sales scope exception to a contract with this fact pattern.

EXAMPLE 3-3

Determination of notional amount — contract to provide power to a load-serving entity

Ivy Power Producers (IPP) participated in the 20X1 load auction in Pennsylvania and was awarded a full requirements contract with Rosemary Electric & Gas Company (REG). Under the terms of the agreement, IPP must supply all of the electric energy, capacity, and ancillary services required to meet a specified percentage of REG's retail customer load. No notional amount is specified in the contract and the amount supplied will depend on actual customer usage. The contract includes a "check-the-box" default provision whereby settlement for default will be determined at the seller's option either (a) in a commercially reasonable manner or (b) based on a formula tied to REG's historical retail load. IPP elected to have default determined based on historical load.

Does the contract have a notional amount?

Analysis

To determine the notional amount of the contract, the guidance on notional amounts of requirements contracts in ASC 815-10-55-7 should be considered.

Excerpt from ASC 815-10-55-7

The conclusion that a requirements contract has a notional amount as defined in this Subtopic can be reached only if a reliable means to determine such a quantity exists. Application of this guidance to specific contracts is as follows:

(a)...One technique to quantify and validate the notional amount in a requirements contract is to base the estimated volumes on the contract's settlement and default provisions. Often the default provisions of requirements contracts will specifically refer to anticipated quantities to utilize in the calculation of penalty amounts in the event of nonperformance. Other default provisions stipulate penalty amounts in the event of nonperformance based on average historical usage quantities of the buyer. If those amounts are determinable, they shall be considered the notional amount of the contract.

Consistent with this guidance, in this fact pattern, the requirements contract has a notional amount that can be determined based on the historical load-based formula included in the default provisions. The fact that the notional amount will fluctuate over time as a result of fluctuations in load does not change the conclusion that the contract has a notional amount (see the response to Question 3-2 regarding load shift). This applies to both parties to the contract. Note that the contract would not have a notional amount if IPP had instead elected to settle any default in a commercially reasonable manner (unless there is another measurable way to determine the notional based on the contract provisions).

In evaluating whether there is a notional amount, the key question is whether there is a quantity specified in the contract that can be enforced by one of the parties to the contract in the event of nonperformance. The quantity may be stable throughout the contract or may require continuous evaluation at various points in time. We believe that the parties to the contract should evaluate all contract provisions, not just default clauses, in assessing whether the contract has a notional amount. In some cases, collateral posting or other requirements, such as margining, may lead to a conclusion that there is a reliably determinable notional amount, if those terms would be used to determine penalties for default. However, if such amounts would provide an input into determining whether a default had occurred but would not be the primary basis for determining the amount of such default penalty, such provisions would typically not support a conclusion that the contract has a notional amount.

EXAMPLE 3-4**Determination of notional amount — contract for electricity sales to a retail customer**

Ivy Power Producers (IPP) enters into a supply agreement with Direct Access Customer 1 (DA1), whereby IPP agrees to provide electricity sufficient to meet DA1's needs as well as providing scheduling and related services. The contract specifies a minimum quantity of electricity that DA1 is required to take. The contract also specifies a maximum quantity. Additional amounts above the maximum may be available at the same price, subject to agreement by both parties to the contract. DA1 must source all of its electricity needs, up to the maximum specified in the contract, from IPP. The contract is silent with respect to resale.

Is the arrangement a requirements contract?

Analysis

The contract is structured to meet DA1's actual needs, and IPP is performing scheduling and other services for the customer. Based on the factors provided, DA1 would be able to purchase additional amounts in excess of its actual needs for resale. Therefore, the requirements contract guidance would not be applicable. This is the case even though DA1 may not have knowledgeable resources to resell the energy and that it may not be practical for this type of customer to take advantage of market fluctuations. Because the requirements contract guidance is not applicable, the contract is a combined forward and option contract, similar to the contract discussed in Example 3-1. However, because this is a contract for power, it may be eligible for the normal purchases and normal sales scope exception provided by ASC 815-10-15-45 through 15-51. See UP 3.3.1 for further information on application of the normal purchases and normal sales scope exception.

Note that the evaluation would be different if the contract specified that DA1 could only take amounts necessary to meet its needs, prohibited resale, or other similar language. In such case, the requirements contract guidance would apply and the notional amount would be equal to the minimum specified in the contract.

EXAMPLE 3-5**Determination of notional amount — natural gas contract with specified source of natural gas**

Assume the same facts as in Example 3-1, except that the source of natural gas supply is specified. Guava Gas Company must supply the natural gas from certain specified wells and is not permitted to source the natural gas from an alternative supply. Ivy Power Producers must take and pay for the minimum quantity specified in the contract unless GGC cannot deliver, in which case IPP is not required to take or pay for the natural gas. IPP also has an option to take additional quantities, if available. There are no specified penalties for nonperformance.

Does the minimum quantity represent a notional amount?

Analysis

Although IPP must take and pay for a minimum quantity, the contract specifies that the source of supply and natural gas cannot be provided by another source and does not include significant penalties for nonperformance. As neither party can effectively be compelled to perform, the minimum quantity does not represent a notional amount. Furthermore, since IPP's option to take additional natural gas is only exercisable if the plant is available and IPP is required to perform only if GGC delivers, there is no notional amount. As such, the contract in this example would not qualify as a derivative in accordance with ASC 815.

Alternatively, assume the contract stated that each month GGC would notify IPP of the estimated volumes available from the wells for the next month, and IPP would notify GGC of the volumes it elected to take by the next day. If the contract required GGC to provide the elected volumes to IPP regardless of the fluctuation of the daily actual production from the wells, then the contract would have a notional amount each month for the subsequent month's sales, as the volume has been fixed and is subject to nonperformance penalties.

EXAMPLE 3-6

Determination of notional amount — plant-specific capacity contract with a proportionate refund of capacity charge for nonperformance

Ivy Power Producers (IPP) agrees to sell all of the electric energy and capacity from Maple Generating Station, a 500 MW natural gas-fired power plant, to Rosemary Electric & Gas Company (REG). Energy and capacity supplied under the agreement must be sourced from the Maple power plant. The plant must perform at 80% (or higher) capacity during the summer peak period. The penalty for nonperformance is a refund of the capacity charge to the extent of nondelivery. For purposes of this example, assume that the contract does not contain a lease.

Does the arrangement contain a notional amount?

Analysis

There is no notional amount in a plant-specific contract where the sole penalty for nonperformance is the refund of a proportion of the capacity charge (i.e., the refund of amounts paid for capacity that was not delivered). The refund of capacity charges equal to the amount not delivered is generally not considered to be a sufficient penalty to compel performance under the contract. As such, the contract does not have a notional and does not meet the definition of a derivative under ASC 815.

EXAMPLE 3-7

Determination of notional amount — plant-specific contract with a refund of current and previously received capacity charges for nonperformance

Assume the same facts as in Example 3-6; however, failure to meet the requirements two years in a row will result in a decrease in the plant's capacity rating under the contract. If the plant capacity rating is reduced, Ivy Power Producers will be required

to refund capacity payments received related to the derated amount from the inception of the contract (i.e., if the capacity rating is reduced from 95% to 90% and the plant is 100 megawatts, it would have to refund all prior capacity payments received related to 5 megawatts of capacity).

Does the contract have a notional amount?

Analysis

IPP should perform an analysis to determine whether the refund penalty is onerous enough that it would be expected to compel performance under the contract. This analysis should compare payments under the contract to the expected market price of power. If the refund of capacity payments is significant, IPP would be expected to ensure the availability of the plant, and would thus conclude that the contract has a notional amount. In the example fact pattern, the penalty is likely sufficient to conclude that the contract has a notional amount. However, if the penalty is relatively small in relation to market prices (e.g., if only a portion of the capacity payment has to be refunded), additional evaluation, such as the existence other non-performance penalty provisions, may be necessary.

EXAMPLE 3-8

Determination of notional amount — non-firm energy contract

Ivy Power Producers (IPP) agrees to sell all of the electric energy from Wisteria Wind Power Plant, a 40 MW wind facility, to Rosemary Electric & Gas Company (REG). Electric energy supplied under the agreement must be sourced from the Wisteria Wind facility. IPP will receive energy payments based solely on amounts delivered (sometimes referred to as “as-available energy”). There is no separate capacity payment and no minimum quantity of energy or capacity specified in the contract. Furthermore, there are no forms of performance assurance or requirements.

Does the contract have a notional amount?

Analysis

A plant-specific contract with pay-for-performance contract terms and no specific performance requirements would not have a notional amount. This conclusion would not change even if IPP had reliably delivered a certain amount under the contract over multiple years. Although the buyer may assume that delivery is probable, there is no assurance of a minimum level of deliveries under the contract, thus, there is no notional amount.

It should be noted that, unlike the discussion of minimum lease payments in UP Question 2-24, where a contract for the forward purchase or sale of power generated from a renewable resource would always be deemed to be contingent rent for lease accounting, a similar arrangement may in fact be deemed to have a notional for derivative accounting if the plant-specific contract stipulates an amount and performance assurance or requirements were accompanied by a significant enough penalty for non-performance.

A penalty based only on availability and not actual production would generally not be indicative of a notional amount. For example, a renewable facility that guarantees it will be available for 90% of the contract term, but has no guarantee for actual production would not include a notional. This is because the facility can be available but not generate any electricity (if there is no sun in the case of a solar facility, or no wind in the case of a wind facility). If the contract guarantees a level of output, even for a fuel source outside the control of the parties, and would require significant compensation for not meeting that level of output, it would include a notional.

EXAMPLE 3-9

Determination of notional amount — plant under construction

Ivy Power Producers (IPP) plans to build a 575 MW combined-cycle natural gas-fired facility, Camellia Generating Station. To issue debt to raise funds to begin construction, in March 20X1 IPP signs a 25-year power sales agreement with Rosemary Gas & Electric Company (REG). REG agrees to purchase 300 megawatts of the capacity and energy generated by the Camellia plant. The power sales agreement specifically states that the capacity and energy must be supplied from the Camellia power plant and cannot be purchased from the market or generated from another facility. In addition, the agreement states that if commercial operation does not begin by January 1, 2015, then either party can terminate the agreement with no obligation by either party to make any payments to the other party. IPP has another off-taker and concludes that the REG contract is not a lease.

Does the contract have a notional amount?

Analysis

This contract does not have a notional amount until the plant is constructed and in commercial operation. Although a quantity is specified in the contract, the quantities can be provided only by the Camellia power plant, which is still under construction. Additionally, if commercial operation is not achieved by the specified date, the contract automatically terminates with no penalties paid. As a result, there is no notional amount for the agreement because there is no stated amount for which delivery can be enforced until the plant is constructed. The contract currently does not represent a binding requirement to purchase or sell any specified amount of power until construction is completed. At that time, additional evaluation of the contract will be required. Note that this conclusion would likely change if there is a significant penalty for failing to complete construction by the deadline (e.g., IPP is required to pay REG the difference between the contract price and the market price if it fails to deliver starting in January 1, 2015).

3.2.2 Initial net investment

The second criterion that needs to be met for an instrument to qualify as a derivative is that no or a minimal initial net investment in the contract is required.

ASC 815-10-15-83(b)

Initial net investment. The contract requires no initial net investment or an initial net investment that is smaller than would be required for other types of contracts that would be expected to have a similar response to changes in market factors.

ASC 815-10-15-94 through 15-98 define a derivative instrument as either a contract that does not require an initial net investment or a contract that requires an initial net investment that, when adjusted for the time value of money, is “less, by more than a nominal amount” than the initial net investment that would be required to acquire the asset related to the underlying or to incur an obligation related to the underlying.

For example, a natural gas contract whereby the purchaser prepays for a fixed quantity of natural gas at a stated price based on a discounted cash flow analysis as of the contract date would not be a derivative in its entirety because an initial net investment is required that is equal to the value of the natural gas. Further evaluation would be required if a reporting entity enters into an in-the-money option contract to purchase natural gas with a significant amount of cash paid at the inception of the contract. The reporting entity would need to assess whether the amount of the upfront payment is more than nominally less than what would otherwise be required to acquire the natural gas and, therefore, results in the contract not meeting the initial net investment criterion.

Although the FASB did not provide a bright line for what constitutes “less, by more than a nominal amount,” its intention appears to be that an initial net investment that is less than at least 90% of the amount that would be exchanged to acquire the asset or incur the obligation would satisfy this criterion. This has been referred to throughout the guide as the no initial net investment criterion.

Question 3-6

Does a plant-specific power contract that requires the construction of a generation facility contain a significant initial net investment represented by the construction costs of the generation facility?

PwC response

No. Capital outlays for construction of the power plant do not form part of the cash flows required to be exchanged under the terms of the power contract itself. Therefore, such cash flows should not be considered in the evaluation of whether the power contract requires an initial net investment.

3.2.3 Net settlement

The third criterion to meet the definition of a derivative is that there is a means to net settle the contract.

ASC 815-10-15-83(c)

Net settlement. The contract can be settled net by any of the following means:

1. Its terms implicitly or explicitly require or permit net settlement.
2. It can readily be settled net by a means outside the contract.
3. It provides for delivery of an asset that puts the recipient in a position not substantially different from net settlement.

Many utilities and power companies enter into financially settled swaps, options, and similar contracts with settlement based on changes in the underlying compared to a reference price included in the contract. Such contracts are net settled in cash and meet the ASC 815-10-15-83(c)(1) net settlement criterion. Evaluation of whether these contracts have net settlement provisions is typically straightforward and is not further discussed in this section.

In contrast, physical contracts for delivery of natural gas or power typically require delivery of the asset that is the subject of the contract (gross physical settlement). However, contracts that require physical delivery may still meet the net settlement criterion. In some cases the contract will permit explicit or implicit net settlement; other physically settled contracts will meet the net settlement criterion because of the existence of a market mechanism or because the contracts require delivery of an asset that is readily convertible to cash. The following sections describe specific considerations with respect to the net settlement evaluation of physically settled commodity contracts.

3.2.3.1 Net settlement under contract terms

When a contract has terms that implicitly or explicitly permit or require net settlement, neither party will be required to deliver an asset that is related to the underlying. Rather, settlement will be in cash or another asset based on the principal or other stated amount in the contract.

Excerpt from ASC 815-10-15-100

In this form of net settlement, neither party is required to deliver an asset that is associated with the underlying and that has a principal amount, stated amount, face value, number of shares, or other denomination that is equal to the notional amount (or the notional amount plus a premium or minus a discount).

As part of the evaluation of whether a contract includes net settlement provisions, all of the contract's default provisions and termination penalties should be evaluated. Figure 3-1 summarizes key considerations in evaluating default provisions.

Figure 3-1
Evaluating default provisions

Net settlement provisions	Not net settlement provisions
<ul style="list-style-type: none"> □ Symmetrical default provisions that allow either party to the contract to unilaterally settle the contract in cash without penalty □ A variable penalty for nonperformance based on changes in the price of the underlying may be a form of net settlement 	<ul style="list-style-type: none"> □ Asymmetrical default provisions that allow the nondefaulting party to demand payment from the defaulting party in the event of nonperformance, but do not result in the defaulting party receiving payments for the effects of favorable price changes □ A fixed penalty for nonperformance (as the penalty does not change with changes in the underlying) □ A variable penalty for nonperformance based on changes in the price of the underlying if it also includes an incremental penalty of a fixed amount (or fixed amount per unit) that is expected to be significant enough at all dates during the remaining term to make the possibility of nonperformance remote

ASC 815-10-15-103 states that penalties for nonperformance within a contract may constitute net settlement, and it provides examples of types of penalties and related guidance. Default provisions in a contract for delivery of a commodity such as natural gas or power may give the contract the characteristic of net settlement. Such provisions should be evaluated at contract inception to determine if they result in implicit net settlement consistent with ASC 815-10-15-100. Default provisions are further discussed in the following sections.

Symmetrical and asymmetrical default provisions

ASC 815-10-15-103 states that a penalty for nonperformance that is based on changes in the price of the items that are the subject of the contract may give the contract the characteristic of net settlement. It further states that net settlement would not occur if the default provisions are asymmetrical. Consistent with this guidance, a contract may have default provisions or termination penalties that constitute implicit net settlement. For example, a contract may include symmetrical default provisions that allow either party to the contract to unilaterally settle the contract in cash or other assets without penalty. Symmetrical default occurs if either party (including a party that defaults) can force payment under the provision. Simplified Example 3-10 provides an illustration of a symmetrical default provision.

Power and natural gas contracts typically do not include the type of default provisions illustrated in Example 3-10. Instead, it is more common to include asymmetrical default provisions such that the nondefaulting party can demand payment from the defaulting party, but cannot be forced to pay the defaulting party. A contract may include language to that effect such as:

“Under no circumstances will the nondefaulting party be required to pay the defaulting party for any gains projected to result to the nondefaulting party (i.e., if the seller is the nondefaulting party, the seller will have no duty to the buyer if the seller is able to resell the power at a higher price in the market).”

ASC 815-10-55-10 through 55-18⁴ describe and provide guidance on asymmetrical default provisions.

ASC 815-10-55-12

Note that an asymmetrical default provision is designed to compensate the nondefaulting party for a loss incurred. The defaulting party cannot demand payment from the nondefaulting party to realize the changes in market price that would be favorable to the defaulting party if the contract were honored.

In addition, ASC 815-10-55-18 further describes the concept of implicit net settlement.

Excerpt from ASC 815-10-55-18

A contract that permits only one party to elect net settlement of the contract (by default or otherwise), and thus participate in either favorable changes only or both favorable and unfavorable price changes in the underlying, meets the derivative characteristic . . . discussed in paragraph 815-10-15-100 for all parties to that contract. Such a default provision allows one party to elect net settlement of the contract under any pricing circumstance and consequently does not require delivery of an asset that is associated with the underlying. That default provision differs from the asymmetrical default provision in the example contract in paragraph 815-10-55-10 because it is not limited to compensating only the nondefaulting party for a loss incurred and is not solely within the control of the defaulting party.

As noted above, to meet the net settlement characteristic described in ASC 815-10-15-100, one or both of the parties to the contract must have the ability to net settle under any pricing circumstances. Net settlement must be solely within the control of one of the parties (i.e., if both of the parties have to agree to net settlement the criterion would not be met) and that party must be able to realize its gains on the contract without delivering the asset associated with the underlying.

Therefore, until default occurs, asymmetrical default provisions do not create the characteristic of net settlement because they do not allow either party to participate in both favorable and unfavorable price changes. However, upon default, the nondefaulting party would have the unilateral right to elect net settlement. In such a case, delivery of the asset would not be required and the net settlement characteristic could be met. In addition, it should be noted that ASC 815-10-55-17 states that a pattern of applying the asymmetrical default provision between certain counterparties would indicate an understanding that there will always be net settlement and

⁴ Guidance originally issued as DIG Issue A8, *Definition of a Derivative: Asymmetrical Default Provisions*.

consideration would need to be made as to whether the criterion in ASC 815-10-15-100 is met.

Question 3-7

Does a contract that does not contain liquidated damages or allow for recourse in the event of default have the characteristic of net settlement?

PwC response

No, unless the contract includes other provisions that explicitly permit net settlement. Many contracts that predate ASC 815 are silent with respect to the calculation of liquidated damages or the method of settlement if one of the parties defaults under the contract. Furthermore, such contracts typically do not include explicit net settlement provisions. As a result, these types of contracts do not have the characteristic of net settlement through contract terms. Although default may lead to a cash payment from one of the parties to the other, this is not typically unilateral (i.e., the defaulting party would not automatically be eligible to receive a payment) and the amount of the payment would require some type of agreement or negotiation. See related Question 3-8.

Question 3-8

Does a contract with damages in the event of default based on commercially reasonable terms have the characteristic of net settlement?

PwC response

No, unless the contract includes other provisions that explicitly permit net settlement. As discussed in this section, to meet the net settlement characteristic described in ASC 815-10-15-100, net settlement must be solely within the control of one of the parties to the contract and that party must be able to realize its gains on the contract without delivering the asset associated with the underlying. A default provision that requires negotiation for settlement based on commercially reasonable terms does not create the characteristic of net settlement because it does not allow either party to participate in both favorable and unfavorable price changes, until a default occurs. Additionally, once default occurs, the parties must then agree to the amount of the damages because no specific formula or method of calculation is specified.

Application example — default provisions

The following simplified example is provided to illustrate the application of the guidance on symmetrical and asymmetrical default provisions. The sample fact pattern has been included solely for the purpose of assessing whether the contract has the characteristic of net settlement in accordance with ASC 815-10-15-83(c)(1).

EXAMPLE 3-10

Evaluation of net settlement – power purchase contract with symmetrical default provision

Ivy Power Producers (IPP) enters into an agreement with Rosemary Electric & Gas Company (REG) to sell an hourly quantity of 100 MWs of firm power during on-peak hours for the month of March 2015 at a price of \$50/MWh. Under the terms of the agreement, if either party fails to perform, a payment will be made for the differential between the contract price and the market price. If the market price is above contract price, IPP will pay REG; if the market price is below contract price, REG will pay IPP. The payment will be made regardless of which party defaults.

During March 2015, the market price of power decreases to \$40/MWh. IPP fails to deliver any power under the contract.

Is the contract able to be net settled?

Analysis

In this fact pattern, REG would be required to pay IPP the market differential, even though IPP did not perform under the contract. Because the contract requires payment regardless of the defaulting party, the contract has the characteristic of net settlement in ASC 815-10-15-83(c)(1).

Note that if the terms of the contract instead stated that under no circumstances would the nondefaulting party be required to pay the defaulting party for any gains projected to result, then the contract would not have the characteristic of net settlement in ASC 815-10-15-83(c)(1).

Fixed and variable penalties

Commodity contracts often include penalties that may be fixed, variable, or a combination of both. The guidance in ASC 815-10-15-103 indicates that a fixed penalty for nonperformance is not considered a net settlement provision because it does not vary with changes in the underlying. A penalty that is variable solely based on changes in the price of the item that is the subject of the contract would be a net settlement provision. In addition, ASC 815-10-15-103(c) provides guidance relating to contracts that have variable and fixed penalties for nonperformance.

ASC 815-10-15-103(c)

A contract that contains a variable penalty for nonperformance based on changes in the price of the items that are the subject of the contract does not contain a net settlement provision as discussed beginning in paragraph 815-10-15-100 if it also contains an incremental penalty of a fixed amount (or fixed amount per unit) that would be expected to be significant enough at all dates during the remaining term of the contract to make the possibility of nonperformance remote. If a contract includes such a provision, it effectively requires performance, that is, requires the party to

deliver an asset that is associated with the underlying. The assessment of the fixed incremental penalty shall be performed only at the contract's inception. The magnitude of the fixed incremental penalty shall be assessed on a standalone basis as a disincentive for nonperformance, not in relation to the overall penalty.

Consistent with this guidance, reporting entities should assess performance penalties at the inception of the contract. Factors to consider include:

- Fixed penalties do not constitute contractual net settlement (because the amount is fixed and does not vary with the underlying).
- Variable penalties should be evaluated further to determine if they are asymmetrical and would therefore not constitute net settlement.
- Variable penalties with an additional fixed penalty that would be sufficient to compel performance would not constitute contractual net settlement.

In addition, any fixed penalties that are sufficient to compel performance would typically create a notional amount. See UP 3.2.1 for further information on the determination of a notional amount.

Question 3-9

Would a power contract that has a penalty based on predetermined rates meet the contractual net settlement criterion?

PwC response

Maybe. Certain bilateral power contracts include contractually scheduled termination penalties that could result in a cash payment from the seller to the buyer if the seller fails to perform under the contract. Qualifying facilities contracts and other contracts with large and/or variable capacity payments frequently include these types of penalties.

Consider a contract in which the termination amount is equal to the difference between the purchase price that would have been paid for electric energy delivered from the project during the operating period based on contractual pricing, and the amount actually paid. In this case, the penalties are based on rates included in the contracts, with no reference to external market prices or expected future deliveries (i.e., a fixed penalty for nonperformance). In contrast, as indicated in ASC 815-10-15-103, a net settlement provision would be based on the market value of expected future deliveries under the contracts. As such, in this example, the termination penalties do not result in net settlement under the contract.

However, note that such penalties may be significant enough to force continued performance under the contract, and in some cases, this may create a notional amount under the contract. See UP 3.2.1 for further information on the determination of a notional amount. In addition, if management concludes that the contract does not

have net settlement provisions as described in ASC 815-10-15-83(c)(1), the contract may still have net settlement provisions under ASC 815-10-15-83(c)(2) or 15-83(c)(3).

Question 3-10

Do contracts with displacement provisions meet the contractual net settlement criterion?

PwC response

Generally, no. Some take-or-pay power contracts include a “displacement” provision that explicitly permits net settlement of a portion of the contract at the concurrence of both parties. Displacement provisions may be exercised if the replacement cost of energy (i.e., the cost to purchase energy in the market) is less than the incremental generation rate (i.e., the cost to produce the energy). Displacement provisions generally require that the parties agree on the period of displacement, the incremental generation rate, the replacement cost, and the amount of power to be displaced. If the parties agree to displacement, the seller will shut down or curtail generation to the extent agreed and the seller will pay a defined percentage of the difference between the incremental generation rate and the replacement cost.

If the displacement provisions are exercised, the parties will cash settle a portion of the contract and physical delivery is not required. Because this contract provision may result in cash payment instead of physical delivery, a question arises as to whether this provision constitutes net settlement. This provision does not eliminate the seller’s obligation to deliver power under the contract. Furthermore, it does not provide a contractual right allowing nonperformance. Neither of the parties has the unilateral right to force net settlement under the contract because the contract requires both parties to agree. As such, the contract does not contain an explicit net settlement provision.

However, the contract may have an implicit net settlement provision if the parties have a pattern of net settling the contract. If the parties ever exercise this provision and displace power under the contract, or expect to exercise this provision at contract inception, the contract would not be eligible for the normal purchases and normal sales scope exception. See UP 3.3.1 for information on the normal purchases and normal sales scope exception.

3.2.3.2 *Net settlement through a market mechanism*

In this form of net settlement, one of the parties is required to deliver an asset equal to the notional amount, but there is an established market mechanism that facilitates net settlement outside the contract.

Excerpt from ASC 815-10-15-110

In this form of net settlement, one of the parties is required to deliver an asset of the type described in paragraph 815-10-15-100, but there is an established market mechanism that facilitates net settlement outside the contract. (For example, an exchange that offers a ready opportunity to sell the contract or to enter into an offsetting contract.) Market mechanisms may have different forms.

The term “market mechanism” should be interpreted broadly and includes any institutional arrangement or other agreement having the requisite characteristics. For example, any institutional arrangement or over-the-counter agreement that permits either party to (1) be relieved of all rights and obligations under the contract and (2) liquidate its net position in the contract without incurring a significant transaction cost is considered to achieve a net settlement. ASC 815-10-15-110 through 15-118 includes detailed information about what constitutes a market mechanism with the primary characteristics summarized in ASC 815-10-15-111.

Excerpt from ASC 815-10-15-111

Regardless of its form, an established market mechanism must have all of the following primary characteristics:

- a. It is a means to settle a contract that enables one party to readily liquidate its net position under the contract...
- b. It results in one party to the contract becoming fully relieved of its rights and obligations under the contract...
- c. Liquidation of the net position does not require significant transaction costs...
- d. Liquidation of the net position under the contract occurs without significant negotiation and due diligence and occurs within a time frame that is customary for settlement of the type of contract.

See DH 2.1.3.2 for further information on the characteristics that should be considered when determining if a market mechanism exists.

Given the continued evolution of commodities markets, all contracts, whether exchange-traded, over-the-counter, or bilateral in nature, should be evaluated to determine whether this criterion is met. Figure 3-2 highlights key considerations in assessing whether a market mechanism exists.

Figure 3-2

Key areas of consideration — market mechanism

-
- The evaluation of whether a market mechanism exists should be performed at inception of the contract and on an ongoing basis (ASC 815-10-15-118).
-

-
- The assessment should be performed at an individual contract level and for the full term of the contract (e.g., the full five-year term of a five-year natural gas supply agreement).
 - An assessment of any prohibitions of one party to assign the contract to a third party should be performed to determine if there is an impact to the contract's ability to be net settled through a market mechanism.
-

The New York Mercantile Exchange (NYMEX) is one common example of a market mechanism for certain commodities, which offers physically settled peak and off-peak power futures and physically settled natural gas futures with various locations. In contrast, most local markets for physically settled power and natural gas contracts do not have a market mechanism for net settlement. There may not be sufficient liquidity in the market or sufficient market participants that are willing and able to transact for such contracts. However, some markets provide for more liquidity than others, which may create a market mechanism for net settlement. See UP 4 for further information on power markets in the United States.

As stated above, the assessment of whether a market mechanism exists should be performed on an individual contract basis and not on an aggregate holdings basis. Because the criteria are applied at the individual contract level, the lack of a liquid market for a group of contracts does not affect the determination of the existence of a market mechanism that facilitates net settlement for an individual contract within that group.

Additionally, ASC 815-10-55-111⁵ emphasizes that the evaluation of whether a contract contains a market mechanism must be made over the entire term of the contract (e.g., a five-year contract must be considered for the full five-year term, not in individual hour, day, or month increments). Multiple independent brokers standing ready to assume the rights and obligations related to one year of a five-year contract would not constitute a market mechanism for the contract at inception. However, if there was only one year left of the contract term, and there were multiple brokers standing ready to step into the rights and obligations for the remaining term, then the contract would meet the net settlement criterion at that time.

As discussed in ASC 815-10-15-111, a threshold of 10% should be used when considering "significant transaction costs" in liquidation of the net position. This is consistent with the guidance in ASC 815-10-15-126, which specifically relates to the determination of whether an asset is readily convertible to cash and states that an entity would consider conversion costs to be significant if they are 10% or more of the gross sales proceeds of the asset based on the spot price at the inception of the contract. If significant transaction costs are required to be incurred in order to liquidate the position, a market mechanism would not exist as it would not meet the required characteristic as discussed in ASC 815-10-15-111(c). This analysis should be conducted at the inception of the contract and be based on the most economically available spot price that can be accessed by the entity.

⁵ Guidance originally issued as DIG Issue A19, *Definition of a Derivative: Impact of a Multiple-Delivery Long-Term Supply Contract on Assessment of Whether an Asset Is Readily Convertible to Cash*.

Question 3-11

Does the ability to enter into offsetting contracts constitute a market mechanism?

PwC response

No. In accordance with ASC 815-10-15-111, a market mechanism provides one party to the contract the ability to become fully relieved of its rights and obligations under the contract. It further states that the ability to enter into an offsetting contract, in and of itself, does not constitute a market mechanism because the rights and obligations from the original contract survive. Generally, an offsetting contract does not replace an original contract's legal rights and obligations and therefore this criterion would not be met.

3.2.3.3 Net settlement by delivery of an asset that Is readily convertible to cash**ASC 815-10-15-119**

In this form of net settlement, one of the parties is required to deliver an asset of the type described in paragraph 815-10-15-100, but that asset is readily convertible to cash or is itself a derivative instrument.

As discussed in ASC 815-10-15-122, in this form of net settlement, "Parties generally should be indifferent as to whether they exchange cash or the assets associated with the underlying." As a result of the growth of independent system operators and regional transmission organizations, as well as the development of bilateral markets for power and natural gas across most of the United States, we generally believe that there is a rebuttable presumption that contracts for delivery of energy or natural gas meet this criterion. However, this presumption may be overcome based on the location of the specific asset, access to active markets, and the volume and liquidity of the markets. See UP 3.6 for further information on accounting for certain common commodity products.

Key considerations for the evaluation of the readily convertible to cash criterion are summarized in Figure 3-3 and are further discussed in the following sections.

Figure 3-3**Key areas of consideration — readily convertible to cash**

-
- The evaluation of whether an asset is readily convertible to cash should be performed at the inception of the contract and on an ongoing basis (ASC 815-10-15-139).
 - A key question in evaluating whether an asset is readily convertible to cash is whether there is an active spot market for the particular product being sold under the contract.
 - The assessment of whether a reporting entity has access to an active market generally should be performed at inception of the contract and should be based on the spot price of the asset on that date (see *Access to an active market* below).
-

-
- Assuming the active spot market can rapidly absorb the quantity specified in the contract for each individual delivery month, and the spot market is expected to be in existence in the future for each delivery date, then the contract is readily convertible to cash.
-

Determining if the market is active

The term readily convertible to cash is defined in ASC 815-10-20.

Definition from ASC 815-10-20

Readily Convertible to Cash: Assets that are readily convertible to cash have both of the following:

- a. Interchangeable (fungible) units
- b. Quoted prices available in an active market that can rapidly absorb the quantity held by the entity without significantly affecting the price.

(Based on paragraph 83(a) of FASB Concepts Statement No. 5, *Recognition and Measurement in Financial Statements of Business Enterprises*.)

The FASB further discussed this criterion in the Basis for Conclusions of FASB Statement No. 133, *Accounting for Derivative Instruments and Hedging Activities* (FAS 133).

Excerpt from FAS 133, paragraph 265

Net settlement is an important characteristic that distinguishes a derivative from a nonderivative because it permits a contract to be settled without either party's accepting the risks and costs customarily associated with owning and delivering the asset associated with the underlying (for example, storage, maintenance, and resale). However, if the assets to be exchanged or delivered are themselves readily convertible to cash, those risks are minimal or nonexistent. Thus, the parties generally should be indifferent as to whether they exchange cash or the assets associated with the underlying.

Paragraph 266 further discusses the FASB's conclusion that readily convertible to cash was the appropriate criterion "because it addresses whether the asset can be converted to cash with little effort." Therefore, to meet this criterion, there should be an active spot market for the particular product being sold under the contract to facilitate the conversion of the asset into cash with minimal effort. Although it may be obvious in some cases that a market is active or inactive, in other situations the determination may be difficult. Reporting entities should consider the definition of an active market in making this assessment. The term "active market" is used throughout the Codification and is defined in ASC 820, *Fair Value Measurement* (ASC 820).

Definition from ASC 820-10-20

Active Market: A market in which transactions for the asset or liability take place with sufficient frequency and volume to provide pricing information on an ongoing basis.

See the PwC *Fair value measurements* guide (FV), FV 4.4.1 for further information on whether data is observable and market-based and FV Question 4-6, which provides guidance on evaluating whether a market is active. This is an area of judgment and a reporting entity's conclusions with respect to a specific market may change over time. As discussed in ASC 815-10-15-139, evaluation of the readily-convertible-to-cash criterion should be performed at inception and on an ongoing basis throughout the contract life (except as specifically discussed in *Access to an active market* below with respect to conversion costs).

Access to an active market

ASC 815-10-15-125 through 15-127⁶ further clarify the definition of readily convertible to cash and provide that an entity should consider conversion (delivery) costs in determining whether an asset is readily convertible to cash. If the estimated conversion costs are 10% or more of the gross sale proceeds that would be received from the sale of those assets in the closest or most economical active market, then the costs are considered significant and the asset would not be readily convertible to cash. The guidance states that the assessment of the significance of conversion costs should be based on the spot price at the inception of the contract and should be performed only at the inception of the contract.

Question 3-12

Should the reporting entity reassess access to a liquid market if a new market emerges?

PwC response

Yes. ASC 815-10-15-126 states that the assessment of conversion costs should be performed only at the inception of the contract. However, in some cases, new markets may emerge subsequent to contract inception.

ASC 815-10-15-139 requires the evaluation of whether items to be delivered under a contract are readily convertible to cash to be performed at inception and on an ongoing basis throughout a contract's life, except for the evaluation of conversion costs. Consistent with this guidance, no reevaluation of conversion costs should be performed if there are no fundamental changes in the market. Reassessment of the classification of a contract would not occur as a result of a change to estimates in the original evaluation (e.g., estimates of line loss, spot price at the active market location, or changes in transportation costs), or a new method to access an existing market.

⁶ Guidance originally issued as DIG Issue A10, *Definition of a Derivative: Assets That Are Readily Convertible to Cash*.

However, in evaluating whether an asset is readily convertible to cash, reporting entities should monitor market changes, such as the emergence of a liquid hub or a new transportation resource, or a substantial decline in the liquidity of a trading point. Market changes may result in the need to reconsider the readily-convertible-to-cash criterion and may change the determination of whether a contract is a derivative.

We believe reporting entities should update their evaluation of conversion costs in response to significant market changes. If a reassessment is performed as a result of a change in the markets, the inputs (e.g., commodity price, transportation cost, line loss) should be updated to reflect current data as of the date of the reevaluation of the contract and the commodity price should be based on the spot price on the date of reevaluation.

Restrictions on resale

The derivatives guidance was amended after its issuance to provide specific guidance stating that restrictions on resale do not impact the evaluation of whether an asset is readily convertible to cash.

ASC 815-10-15-132

Restrictions imposed by a stock purchase warrant on the sale or transfer of shares of stock that are received from the exercise of that warrant issued by an entity for other than its own stock (whether those restrictions are for more or less than 32 days) do not affect the determination of whether those shares are readily convertible to cash. The accounting for restricted stock to be received upon exercise of a stock purchase warrant shall not be analogized to any other type of contract.

There is a limited exception to this guidance that relates to the sale of stock by its issuer, in which case the restriction would impact the assessment. Other restrictions on resale would not impact the determination of whether an asset is readily convertible to cash.

Question 3-13

Is the asset delivered under a contract considered readily convertible to cash if one of the counterparties is limited as to resale?

PwC response

Yes. In certain cases, one of the parties to a contract may have tax-exempt financing or other restrictions that limit or preclude resale of the product outside a specified area (e.g., “two-county bonds”). Restrictions outside the contract itself should not be considered in evaluating whether a contract is a derivative. Therefore, in general, these types of restrictions would not impact the evaluation of whether the contracts require delivery of an asset that is readily convertible to cash. Similarly, a natural gas supply contract that has a contractual restriction on resale by the buyer, but requires delivery at a location where the delivery of the asset would be readily convertible to cash exclusive of the terms of the contract, would still be considered readily

convertible to cash and qualify to be a derivative if the other elements of the definition are met (e.g., notional, underlying).

Question 3-14

Are the assets delivered under a plant-specific contract readily convertible to cash?

PwC response

Generally, yes. Many contracts, such as power supply contracts from qualifying facilities and other plant-specific power purchase agreements, require that the supplier provide power from a specific facility. The assessment of whether an asset is readily convertible to cash should consider the rights and abilities of both parties under the contract. The fact that a contract is linked to a specific facility does not affect this evaluation. If either of the parties to the contract has the ability to access active markets without significant incremental costs (i.e., transportation/transmission), both parties should account for the contract as a derivative (assuming other derivative criteria are met). This would be the case even if one of the parties to the contract cannot access a liquid market.

Impact of transaction volume

Assets that are readily convertible to cash have active markets that can rapidly absorb the quantity held by the reporting entity without significantly affecting the price. Determining whether an active market can rapidly absorb the contract quantity requires judgment. ASC 815-10-55-99 through 55-110⁷ provide guidance on how transaction volume impacts the assessment of whether an asset is readily convertible to cash. The spot market should be evaluated by comparing the daily commodity contract quantity to the daily transaction volume to determine if and how the market price could be impacted by the contract. If the price would not be significantly impacted, then the market can rapidly absorb the contract. For example, delivery of the power from a supply contract with large daily contract volumes to a market with historically low daily volumes may significantly impact the power price. If that is the case, the asset delivered under the contract would not be readily convertible to cash.

In addition, ASC 815-10-15-128 clarifies the evaluation of contracts involving multiple deliveries.

ASC 815-10-15-128

For contracts that involve multiple deliveries of the asset, the phrase *in an active market that can rapidly absorb the quantity held by the entity* in the definition of *readily convertible to cash* shall be applied separately to the expected quantity in each delivery.

⁷ Guidance originally issued as DIG Issue A12, *Definition of a Derivative: Impact of Daily Transaction Volume on Assessment of Whether an Asset Is Readily Convertible to Cash*.

For example, in evaluating a five-year supply contract that requires delivery of a specified quantity at a predetermined price each month, the reporting entity would need to assess whether the market could rapidly absorb the specified quantity each month rather than considering whether the market could absorb the total contract quantity to be delivered over the five years.

Question 3-15

Are the assets delivered under a long-term supply contract readily convertible to cash if there is no forward market?

PwC response

Generally, yes. The evaluation of whether an asset is readily convertible to cash is based on the spot market, not the forward market.

Excerpt from ASC 815-10-55-116

The five-year commodity supply contract meets the net settlement characteristic as discussed beginning in paragraph 815-10-15-119. The criterion discussed beginning in that paragraph [readily convertible to cash] is met because an active spot market for the commodity exists today and is expected to be in existence in the future for each delivery date...under the multiple delivery supply contract. The spot market can rapidly absorb the quantities specified for each monthly delivery without significantly affecting the price.

Assuming the active spot market can rapidly absorb the quantity specified in the contract for each individual delivery month, and the spot market is expected to be in existence in the future for each delivery date, then the contract is readily convertible to cash.

However, a reporting entity should assess whether it can reliably expect to have access to active spot markets for future deliveries under a contract. For example, due to congestion and other factors, in certain areas, there may be significant volatility in market prices associated with demand, plant maintenance, available supply, and weather. If a reporting entity has difficulty accessing active markets during certain periods, this may lead to an overall conclusion that the contract is not readily convertible to cash. This is a matter of judgment and careful evaluation is required.

3.3 *Scope exceptions*

Notwithstanding the definition of a derivative discussed in UP 3.2, ASC 815 provides that certain types of contracts are not within its scope if specified criteria are met. ASC 815-10-15-13 defines 14 types of contracts that may not be subject to the requirements of the standard. Two of those exceptions that may apply to commodity contracts common in the utility and power industry are:

- Normal purchases and normal sales

- Certain contracts that are not traded on an exchange

This section describes application of these exceptions. See DH 2.2 for further information on the other scope exceptions provided by ASC 815.

3.3.1 **Normal purchases and normal sales scope exception**

ASC 815 provides an elective exception to the application of fair value accounting for physically settled derivative contracts that meet the definition of normal purchases and normal sales. If a utility or power company has entered into a physically settled commodity contract that meets the definition of a derivative, it may seek to apply this exception to avoid derivative accounting and related disclosures. The term “normal purchases and normal sales” is specific to ASC 815.

ASC 815-10-15-22

Normal purchases and normal sales are contracts that provide for the purchase or sale of something other than a financial instrument or derivative instrument that will be delivered in quantities expected to be used or sold by the reporting entity over a reasonable period in the normal course of business.

To designate one or more contracts as normal purchases or normal sales, the reporting entity should evaluate the contracts within the context of its business and operational requirements. In addition, each contract should be further evaluated to ensure that it meets the technical requirements for designation under the scope exception.

ASC 815-10-15-25 and 15-26 summarize the key elements needed to qualify for the normal purchases and normal sales scope exception, and discuss the types of contracts that may have unique considerations. Figure 3-4 highlights these requirements.

Figure 3-4
Overall factors required for the normal purchases and normal sales scope exception

Area	Key considerations
Normal terms (UP 3.3.1.1)	<ul style="list-style-type: none"> □ The contract involves quantities that are expected to be used or sold by the reporting entity in the normal course of business
Clearly and closely related underlying (UP 3.3.1.2)	<ul style="list-style-type: none"> □ Contract pricing is clearly and closely related to the asset being purchased or sold □ The criteria for clearly and closely related for the normal purchases and normal sales scope exception are different than the clearly and closely related criteria in an embedded derivative analysis (see UP 3.4 for further discussion of embedded derivatives)

Area	Key considerations
Probable physical settlement (UP 3.3.1.3)	<ul style="list-style-type: none"> □ It is probable that the contract will gross physically settle throughout the term of the contract (no net cash settlement) □ Changes in counterparty credit should be considered in the ongoing evaluation of probable gross physical delivery □ Net settlement of a contract will result in loss of application of the exception for that contract; it will also call into question whether other similar contracts still qualify
Documentation (UP 3.3.1.4)	<ul style="list-style-type: none"> □ Failure to meet the documentation requirements precludes application □ Documentation should include information on the basis for the reporting entity's conclusion that the contract qualifies for the exception □ Documentation can be maintained for individual contracts or groups of similar contracts □ Designation is elective, but irrevocable; designation is permitted at inception or at a later date □ A contract or group of contracts may also be conditionally designated (Question 3-21)
Type of contract (UP 3.3.1.5)	<ul style="list-style-type: none"> □ The contract is a forward contract without volumetric optionality or a power purchase or sale agreement that is a capacity contract ("power contract exception") □ Criteria for the power contract exception are incremental to the general requirements

In accordance with ASC 815-10-15-23, the assessment of whether a contract qualifies for the exception should be performed only at the inception of the contract; however, as discussed in UP 3.3.1.4, the documentation and designation can be done at inception or a later date (application of the election commences at the time documentation is completed). In addition, because the normal purchases and normal sales scope exception is elective, its application will sometimes result in different parties to the transaction reaching different conclusions relating to whether a specific contract is required to be accounted for as a derivative instrument.

All of the relevant criteria should be met to qualify for the normal purchases and normal sales scope exception. Each of these areas is further discussed in the following sections.

3.3.1.1 Normal terms

To qualify for the normal purchases and normal sales scope exception, management should evaluate the reasonableness of the contract quantities and terms in relation to the reporting entity's underlying business requirements. This evaluation requires

judgment and a two-step conclusion that the reporting entity intends to take physical delivery and that the quantity delivered will be used in its normal business activities.

ASC 815-10-15-28 provides a series of relevant factors that should be considered when making these determinations.

ASC 815-10-15-28

In making those judgments, an entity should consider all relevant factors, including all of the following:

- a. The quantities provided under the contract and the entity's need for the related assets
- b. The locations to which delivery of the items will be made
- c. The period of time between entering into the contract and delivery
- d. The entity's prior practices with regard to such contracts.

In addition to the factors above, ASC 815-10-15-29 provides further examples of evidence that may assist in identifying contracts that qualify for the normal purchases and normal sales scope exception including: past trends, expected future demand, other contracts for delivery of similar items, the entity's practice for acquiring and storing the related commodities, and operating locations.

To designate a contract under the normal purchases and normal sales scope exception, the reporting entity should be able to assert that the contract is supplying or selling goods as part of its normal business activities. For example, in performing the evaluation for a normal purchase, a reporting entity should consider all of its sources of supply of the applicable commodity in relation to its needs to ensure it is reasonable to assert it will take physical delivery. See UP 3.3.1.5 for further factors to consider based on the type of contract.

3.3.1.2 *Clearly and closely related underlying*

Another criterion in the evaluation of the normal purchases and normal sales scope exception is that the pricing in the contract is clearly and closely related to the asset being purchased or sold. The guidance on clearly and closely related for the normal purchases and normal sales scope exception is included in ASC 815-10-15-30 through 15-34.⁸

⁸ Guidance originally issued as DIG Issue C20, *Scope Exceptions: Interpretation of the Meaning of Not Clearly and Closely Related in Paragraph 10(b) regarding Contracts with a Price Adjustment Feature*.

Excerpt from ASC 815-10-15-30

Contracts that have a price based on an underlying that is not clearly and closely related to the asset being sold or purchased (such as a price in a contract for the sale of a grain commodity based in part on changes in the Standard and Poor's index) . . . shall not be considered normal purchases and normal sales.

The clearly and closely related assessment for determining whether a contract is eligible for the normal purchases and normal sales scope exception considers both qualitative and quantitative considerations. ASC 815-10-15-32 states that the pricing adjustment would not be clearly and closely related to the asset being sold in certain specified circumstances.

Excerpt from ASC 815-10-15-32

- a. The underlying is extraneous (that is, irrelevant and not pertinent) to both the changes in the cost and the changes in the fair value of the asset being sold or purchased, including being extraneous to an ingredient or direct factor in the customary or specific production of that asset.
- b. If the underlying is not extraneous as discussed in (a), the magnitude and direction of the impact of the price adjustment are not consistent with the relevancy of the underlying. That is, the magnitude of the price adjustment based on the underlying is significantly disproportionate to the impact of the underlying on the fair value or cost of the asset being purchased or sold (or of an ingredient or direct factor, as appropriate).
- c. The underlying is a currency exchange rate involving a foreign currency that meets none of the criteria in paragraph 815-15-15-10(b) for that reporting entity.

ASC 815-10-15-33 provides further guidance for evaluating contracts in which the price adjustment focuses on the changes in the fair value of the asset being purchased or sold. In accordance with this guidance, a price adjustment should be expected, at contract inception, to impact the price in a manner comparable to the outcome that would be obtained if, at each delivery date, the parties were to reprice under then-existing conditions. This guidance can be applied to the fair value or the cost of the asset being sold or purchased.

In addition to these pricing factors, to qualify for the normal purchases and normal sales scope exception, the purchase or sale contract is denominated in a currency that meets the requirements of ASC 815-15-15-10(b). See DH 2.2.2.1 for further information on foreign currency considerations in evaluating whether a contract qualifies for the normal purchases and normal sales scope exception.

Application examples — normal purchases and normal sales scope exception: clearly and closely related evaluation

The following simplified examples illustrate the application of the guidance on clearly and closely related pricing. The sample fact patterns have been included solely for the purpose of assessing whether the contract pricing qualifies as clearly and closely related for purposes of the normal purchases and normal sales scope exception.

EXAMPLE 3-11

Determining whether pricing is clearly and closely related — power contract pricing linked to natural gas

Ivy Power Producers (IPP) has a power sales contract with Rosemary Electric & Gas Company (REG). IPP intends to supply REG from the Maple Generating Station, a 500 MW natural gas-fired power plant. The pricing in the contract is linked to a natural gas index.

Does the contract qualify for the normal purchases and normal sales scope exception?

Analysis

In evaluating whether this contract qualifies for the normal purchases and normal sales scope exception, IPP would consider the following factors:

□ *Source (cost) of production*

In evaluating pricing mechanisms, the guidance permits reporting entities to consider the impact of the underlying on the fair value or the cost of the asset being purchased or sold. In this example, the fuel expected to be used to generate the energy under this contract is natural gas. Therefore, a pricing mechanism using a natural gas index would not be extraneous to the cost of the asset being sold.

However, if the underlying plant did not use natural gas (e.g., if it was a coal or wind facility), changes in a natural gas index would not be reflective of the reporting entity's cost of production. In that case, because the natural gas index is not related to the cost of production, the reporting entity would need to assess whether the natural gas index is pertinent to the fair value of the power. In practice, reporting entities have found it difficult to demonstrate that changes in natural gas prices are highly correlated to the fair value of energy produced. Therefore, it may be difficult to conclude that a natural gas index is clearly and closely related to the asset being purchased or sold if the expected source of production is not a natural gas-fired facility.

□ *Natural gas index*

IPP should also specifically consider the natural gas index used in the contract. For example, assume the pricing in the contract is linked to a Henry Hub contract traded on NYMEX. However, the Maple power plant is located near the SoCal

Border trading point (a market hub for natural gas located in California) and that is where IPP purchases natural gas for production. In that case, IPP would need to consider the natural gas price relationship between Henry Hub and SoCal Border. IPP would need to support that the impact of the price adjustment is of the same magnitude and direction as the underlying asset to reach a conclusion that the pricing is clearly and closely related.

□ *Potential leverage*

IPP should consider whether the effect of the natural gas indexation in the pricing formula is proportionate to the impact of natural gas prices on the cost of production. If there is a disproportionate effect (i.e., the effect of natural gas is leveraged or other cost components are being indexed to natural gas prices), the contract will not qualify for the normal purchases and normal sales scope exception. However, if the pricing mechanism limits the adjustment to the proportionate impact that natural gas prices have on the cost of producing energy, it will be considered clearly and closely related.

Evaluation of whether pricing is clearly and closely related to the asset being purchased or sold requires judgment. Each of these key factors as well as other relevant facts should be considered in making this evaluation.

EXAMPLE 3-12

Determining whether pricing is clearly and closely related — heat rate contract

Assume the same facts as in Example 3-11 except that the contract includes a formula that is based on a specified heat rate multiplied by a natural gas index. Under the terms of the contract, the off-taker, Rosemary Electric & Gas Company pays for natural gas for generation, based on the heat rate specified in the contract. If the specified heat rate is higher than the plant heat rate, REG will pay more for natural gas than will be purchased by IPP for use in operations.

Is the pricing formula considered clearly and closely related to the asset being sold?

Analysis

This type of pricing formula may be considered clearly and closely related to the asset being purchased or sold, provided that the specified heat rate used is a reasonable approximation of the expected heat rate for the power to be delivered under the contract. For example, if the contract heat rate is 7.5 and the plant expected to serve the obligation has a heat rate of 7.25, we would generally conclude that the contract pricing may qualify as clearly and closely related for purposes of applying the normal purchases and normal sales scope exception. We accept some difference between the expected system or plant heat rate and the contract heat rate because of operational constraints and profit margin, but would not expect the heat rate to vary from the actual by more than a reasonable profit margin.

However, if the specified heat rate significantly exceeds the expected plant or system heat rate (e.g., in the case of a heat rate established based on market prices), the

pricing formula may be viewed as having leveraged the effect of natural gas prices or, alternatively, having indexed other non-fuel cost components to natural gas prices. Consequently, the pricing under the contract would not be considered clearly and closely related to the asset being purchased or sold and would not be eligible for the normal purchases and normal sales scope exception.

EXAMPLE 3-13

Determining whether pricing is clearly and closely related — pricing escalated based on fuel, labor, and operations and maintenance costs

Ivy Power Producers (IPP) has a capacity sales contract that is serviced from the Maple Generating Station, a 500 MW natural gas-fired generation facility. The entire energy charge is escalated annually based on the Maple power plant's actual variable cost for fuel, labor, and other operations and maintenance costs.

Is the pricing mechanism clearly and closely related to the asset being sold?

Analysis

The cost of producing energy comprises fuel, labor, and other operations and maintenance costs. Assuming the contract pricing formula is based on the respective proportion represented by each of these cost components in the production of the power under the contract, the pricing mechanism is considered clearly and closely related to the asset being sold. In that case, the contract would be eligible for the normal purchases and normal sales scope exception (assuming all other criteria are met).

A conclusion that the pricing is clearly and closely related generally should be supported by an analysis demonstrating the relative cost of production of energy from the plant or group of plants supplying the contract compared to the contract terms. Although the proportions do not have to match exactly, if the ranges are not closely aligned, it may suggest that the contract includes leverage and would not qualify for the normal purchases and normal sales scope exception.

EXAMPLE 3-14

Determining whether pricing is clearly and closely related — pricing escalated based on actual costs and inflation

Assume the same facts as in Example 3-13. However, the energy charge is based on a combination of two components: fuel costs, which are escalated based on Ivy Power Producers' actual costs of fuel, and operations and maintenance costs, which are indexed to the Consumer Price Index.

Is the pricing mechanism clearly and closely related to the asset being sold?

Analysis

It depends. The cost of producing energy comprises fuel, labor, and other operations and maintenance costs. Because fuel costs are typically the most volatile cost component, the parties may choose to price the fuel costs based on actual costs

incurred while the operations and maintenance charges are originally priced based on actual cost, with subsequent years adjusted based on the CPI. We understand that a CPI index is often used because it simplifies the pricing mechanism and is viewed as a suitable proxy for the actual movement in operations and maintenance costs given their relatively modest expected volatility.

If IPP concludes that the CPI is an appropriate (and not extraneous) factor, it should further evaluate the relative proportion of the costs tied to fuel versus CPI. Consistent with Example 3-13, the analysis should ensure that the relative linkage to the natural gas index and the CPI in the contract is consistent with the actual cost of production. It may be concluded that the pricing mechanism is clearly and closely related to the asset being sold, if (a) CPI is not extraneous, and (b) the magnitude and direction of the impact of the CPI adjustment is not significantly disproportionate to the impact of the underlying on the fair value of the asset or the actual cost of production.

EXAMPLE 3-15

Determining whether pricing is clearly and closely related — pricing escalated based on inflation

Assume the same facts as in Example 3-14. However, the entire energy charge is escalated annually based on changes in the CPI.

Is the pricing mechanism clearly and closely related to the asset being sold?

Analysis

No. The guidance in ASC 815-10-15-30 through 15-34 does not prohibit the use of a broad market index as a proxy for changes in the underlying cost. However, to conclude that the pricing is clearly and closely related, a reporting entity would need to be able to assert that the direction and magnitude of changes in the index are reflective of changes in the cost or fair value of the asset being sold.

The cost of producing energy comprises fuel, labor, and other operations and maintenance costs. Although these costs may be included in the items used to determine the CPI, and certain of these costs may actually correlate with the CPI from time to time, the direction and magnitude of changes in the CPI would not be expected to reflect changes in the cost of producing energy as a whole. Therefore, a contract that has the entire energy charge (fuel, labor, and operations and maintenance) solely indexed to the CPI would not be considered to have a pricing mechanism that is clearly and closely related to the underlying and would not qualify for the normal purchases and normal sales scope exception.

A similar conclusion would be reached in evaluating a natural gas contract with price changes based on the CPI because changes in the CPI would not be reflective of changes in the related natural gas index. As such, the pricing would not be considered to be clearly and closely related and the contract would not qualify for the normal purchases and normal sales scope exception.

EXAMPLE 3-16

Determining whether pricing is clearly and closely related — pricing adjusted for avoided cost of production

Ivy Power Producers (IPP) enters into a power sales contract with Rosemary Electric & Gas Company (REG). The power under the contract will be provided from IPP's Wisteria Wind Power Plant, a 40 MW wind facility. The contract's pricing includes a periodic adjustment that is based on REG's avoided cost of production, which is primarily linked to a combination of coal and natural gas-fired generation. Because IPP is supplying from a wind facility, it has no fuel cost of production.

Is the price adjustment clearly and closely related to the asset being sold?

Analysis

No. In evaluating whether the price adjustment is clearly and closely related, IPP should assess the impact of the pricing on changes in the cost or fair value of the asset being sold. In this case, neither IPP's cost of production nor the fair value of power delivered under the contract would be expected to be correlated to REG's avoided cost of production. As such, the pricing would not be considered to be clearly and closely related to the asset being sold and the contract would not qualify for the normal purchases and normal sales scope exception.

3.3.1.3 ***Probable physical settlement***

One of the key criteria for application of the normal purchases and normal sales scope exception is that physical delivery should be probable at inception and throughout the term of the contract. As a result, this criterion should be evaluated at the time the contract is initially designated as a normal purchase or normal sale as well as on an ongoing basis throughout the life of the contract. This section discusses considerations in assessing physical settlement as well as the impact if net settlement occurs (referred to as tainting).

Contract characteristics

In evaluating whether physical settlement is probable, a reporting entity should assess the contract for certain specific characteristics as described in the following sections.

Contract terms allow net settlement or there is a market mechanism for net settlement

Some contracts require physical delivery by their contract terms (i.e., those contracts that meet the net settlement criterion because they require delivery of an asset that is readily convertible to cash). However, other contracts may permit physical or financial settlement. Therefore, to qualify for the normal purchases and normal sales scope exception, ASC 815-10-15-35 has specific requirements for contracts that meet the characteristic of net settlement because of the terms of the contract itself or because there is a market mechanism to facilitate net settlement:

Excerpt from ASC 815-10-15-35

To qualify for the normal purchases and normal sales scope exception, it must be probable at inception and throughout the term of the individual contract that the contract will not settle net and will result in physical delivery.

Note that specific consideration of physical delivery is required for these contracts because the parties to the contract have alternative options for cash settlement (whether through the contract itself or through the ability to be relieved of the contract rights and obligations through a market transaction). For all contracts designated as normal purchases and normal sales, physical delivery should be probable at inception and throughout the term of the contract. See UP 3.3.1.3 *Subsequent accounting* for discussion of the accounting implications if there is a change in the assessment of whether a contract will be physically settled.

Contract results in periodic cash settlement of gains and losses

ASC 815-10-15-36 indicates that application of the normal purchases and normal sales scope exception is not permitted for contracts that cash settle on a periodic basis.

Excerpt from ASC 815-10-15-36

The normal purchases and normal sales scope exception only relates to a contract that results in gross delivery of the commodity under that contract. The normal purchases and normal sales scope exception shall not be applied to a contract that requires cash settlements of gains or losses or otherwise settle[s] gains or losses periodically because those settlements are net settlements.

This concept is also addressed in ASC 815-10-15-41, which states:

Excerpt from ASC 815-10-15-41

Contracts that require cash settlements of gains or losses or are otherwise settled net on a periodic basis, including individual contracts that are part of a series of sequential contracts intended to accomplish ultimate acquisition or sale of a commodity, do not qualify for the normal purchases and normal sales scope exception.

For example, futures contracts traded on an exchange qualify for net settlement due to the existence of a market mechanism. Although this type of contract is for future delivery of a commodity (i.e., the contract will be physically settled at termination), the exchange typically requires daily cash settlements. As such, the contract would not qualify for the normal purchases and normal sales scope exception.

*Transactions within an ISO***Question 3-16**

Would a contract result in physical settlement if a reporting entity obtained flash title of a commodity?

PwC response

Flash title is considered to be obtained when a commodity is physically purchased and then instantaneously physically sold to another party, resulting in the reporting entity obtaining title for an instant prior to it being sold. Generally, if a reporting entity obtains flash title, it would still be able to qualify for the scope exception as long as the contract is executed as part of the entity's normal course of business and meets the other requirements for scope exception.

Flash title is often found in electricity contracts, in which case the contract may qualify for the scope exception through the power contract exception discussed in UP 3.3.1.5 *Certain power contracts*.

Question 3-17

Would a contract for either the forward purchase or sale of electricity within an ISO qualify for the normal purchases and normal sales scope exception?

PwC response

It depends. If a reporting entity is purchasing or selling power within an ISO that results in the purchase of electricity at one location and the sale of that electricity at another location within the ISO, the forward transaction may still qualify for the scope exception if it ultimately results in physical delivery of the commodity, is part of the entity's normal course of business, and meets the remaining requirements for the scope exception. For example, if an entity has an end use customer at an illiquid node, the entity may enter into a forward contract to purchase power at a more liquid location. Then, on a daily basis, the entity would sell the forward power purchased at the liquid node and then purchase spot electricity at the illiquid node. As the power is being physically purchased on the forward contract, and to the extent that the volumes purchased are not greater than their load requirements, the requirement for the commodity to be physically delivered has been met and would not by itself preclude the scope exception. The other requirements for the scope exception would also have to be met.

Counterparty creditworthiness

Gross physical delivery is required for a contract to qualify for the normal purchases and normal sales scope exception. Therefore, at inception and throughout the term of the contract, a reporting entity should assess the creditworthiness of its counterparty. Poor counterparty credit quality at the inception of the arrangement, or subsequent deterioration of the counterparty's credit quality, which may result from issues

relating to the counterparty itself and/or broad economic factors, may call into question whether it is probable that the counterparty will fulfill its performance obligations under the contract (i.e., make physical delivery throughout the contract and upon its maturity). As a result, a reporting entity should monitor and consider the impact of credit risk of the counterparty, as well as its own credit, in assessing whether physical delivery is probable.

Subsequent accounting

On an ongoing basis, a reporting entity should monitor whether it continues to expect contracts designated under the normal purchases and normal sales scope exception to result in physical delivery. ASC 815-10-15-41 discusses the impact of net settlement on the normal purchases and normal sales designation.

Excerpt from ASC 815-10-15-41

Net settlement...of contracts in a group of contracts similarly designated as normal purchases and normal sales would call into question the classification of all such contracts as normal purchases or normal sales.

Consistent with this guidance, a reporting entity should monitor any contracts designated as normal purchases or normal sales to ensure that physical delivery is still probable. This section discusses factors to consider in monitoring the probability of physical delivery, the timing of recognition if net settlement is expected to occur, as well as the subsequent accounting if there is a tainting event.

Monitoring the physical delivery assertion

One way to support the continued expectation that the forecasted transaction will result in physical delivery is to perform backtesting of contracts that settled during the period that were designated under the normal purchases and normal sales scope exception. Another approach is to review the forecast of production, or physical purchases and sales, and compare the forecast to the current portfolio of contracts that are designated under the normal purchases and normal sales scope exception.

If a reporting entity has multiple contracts for which the normal purchases and normal sales scope exception has been elected, it should ensure that physical delivery of the volumes for all of those contracts is probable. Factors that may change the assessment that a contract will result in physical delivery include:

- Changes in the reporting entity's expected production levels
- Changes in markets and demand or supply in the region
- Changes in the reporting entity's or the counterparty's creditworthiness
- Macro changes in the overall economy

The ongoing evaluation of whether physical delivery is probable should incorporate information about any changes to the business approach used by the reporting entity, net settlement of any contracts, changes in market conditions, and other relevant factors.

Timing of recognition when physical delivery is no longer probable

Once a reporting entity elects the normal purchases and normal sales scope exception, it is irrevocable (see UP 3.3.1.4 *Timing of election*). However, if a reporting entity determines that it is no longer probable that a contract will result in physical delivery, it may need to discontinue application. Whether and when a reporting entity should discontinue application of the normal purchases and normal sales scope exception partially depends on the form of net settlement applicable to the contract.

Figure 3-5

Impact of form of net settlement on the requirement or ability to discontinue the application of the normal purchases and normal sales scope exception

Method of net settlement	Timing of change in designation
Net settlement under contract terms (ASC 815-10-15-99a) Net settlement through a market mechanism (ASC 815-10-15-99b)	The normal purchases and normal sales scope exception will cease to apply when physical delivery is no longer probable; this could occur prior to the actual net settlement.
Net settlement by delivery of asset that is readily convertible to cash (ASC 815-10-15-99c)	The normal purchases and normal sales scope exception will continue to apply until net settlement actually occurs, even if management intends or otherwise knows the contract will net settle in the future.

If a reporting entity determines it is no longer probable that a contract will result in physical delivery and the contract allows for net settlement via the contract or because of a market mechanism, the reporting entity should immediately cease to apply the normal purchases and normal sales scope exception to the contract. To qualify for the normal purchases and normal sales scope exception, the reporting entity should be able to assert that physical delivery is probable (see UP 3.3.1.3). Once it is no longer able to make this assertion, the contract no longer meets the criteria for the exception. Accordingly, the contract would be recorded at fair value in the financial statements in the period in which the reporting entity determines that it no longer meets the probability requirement, with an immediate impact to earnings. In addition, subsequent changes in fair value of the derivative are also recognized in earnings.

If, however, the contract meets the net settlement criterion of the definition of a derivative because it requires delivery of an asset that is readily convertible to cash, then the contract’s designation cannot be changed until the net settlement occurs. Thus, the contract would not be initially or subsequently recorded at fair value until the net settlement occurs. This type of contract requires gross physical delivery under

the contract terms; therefore, physical delivery is assumed in assessing whether the normal purchases and normal sales scope exception applies. Because the normal purchases and normal sales scope exception is irrevocable, a reporting entity cannot change the designation of a contract before it is net settled, even if it determines that net settlement is probable, unless it amends the contract to permit net settlement under the contract terms. Furthermore, once such a contract is net settled, it is immediately tainted.

If a reporting entity determines that one contract no longer qualifies for the normal purchases and normal sales scope exception, this may call into question its ability to assert probable physical delivery for other similar contracts or contracts within a group. It may also call into question the entity's initial election of the normal purchases and normal sales scope exception. See further discussion of tainting in the following section.

Subsequent impact of net settlement (Tainting)

The normal purchases and normal sales scope exception applies solely to contracts that result in gross physical delivery of nonfinancial items. Therefore, a reporting entity that designates a contract as a normal purchases or normal sales contract should be able to assert that the contract will not net settle. Net settlement of a particular contract would preclude application of the normal purchases and normal sales scope exception to that contract (i.e., the contract should be recorded at fair value in earnings at the time the exception is no longer applicable as discussed in UP 3.3.1.3 *Timing and recognition when physical delivery is no longer probable*). In addition, it may “taint” the ability to apply the normal purchases and normal sales scope exception to other similar contracts and to the business in its entirety.

Question 3-18

How many times does a reporting entity have to net settle a normal purchases or normal sales contracts to be precluded from applying the exception to future contracts?

PwC response

ASC 815 does not contain guidance on how many contracts designated under the normal purchases and normal sales scope exception can be net settled before similar contracts are tainted. Although a reporting entity should consider its facts and circumstances, we would expect that it would be unusual for management to continue to apply the normal purchases and normal sales scope exception to a group of contracts after more than one or two net settlements, except in very rare circumstances. For example, a reporting entity may net settle a contract for the delivery of natural gas due to economic considerations whereby it decided to monetize an unrealized gain. We would consider this a tainting event that may require de-designation of the entire group of contracts. However, a net settlement due to a supplier bankruptcy may be viewed as a one-time, unpredictable event that taints the particular contract but not the reporting entity's entire group of contracts.

Net settlement as described in ASC 815-10-15-83(c)(3) (readily convertible to cash) is not referenced in the normal purchases and normal sales scope exception. This is because contracts that are readily convertible to cash have terms that do not provide for a net settlement between the parties either directly or through a market mechanism. However, there may be situations in which counterparties agree to a net cash settlement of a contract even if the terms of the contract do not provide for a net settlement. We would consider a negotiated settlement of this type to be a net settlement that results in a tainting event that would need to be evaluated as described above. Accordingly, the circumstances resulting in net cash settlement of contracts that are readily convertible to cash and designated as normal purchases and normal sales will have to be monitored carefully.

Question 3-19

Does a force majeure event taint a contract designated under the normal purchases and normal sales scope exception?

PwC response

No. Certain commodity purchase and sale contracts, which meet the definition of a derivative, may contain a force majeure clause that provides for the cancellation of all or part of the contract when force majeure events occur. Typically, such events are defined in the contract as situations where one of the parties cannot perform in accordance with the terms of the contract as a result of circumstances that are outside its control. Examples of force majeure events include the shutdown of a facility as a result of a fire, flood, or major weather event such as a hurricane. Contracts may also expand the definition of force majeure to include events that are less extraordinary in nature, such as those due to an unplanned maintenance shutdown resulting from the breakdown of critical operating equipment. Oftentimes when force majeure events occur, the contract calls for cancellation of the delivery of the applicable quantities without penalty or net settlement.

In such cases, although no delivery occurs, there is usually no net settlement of the contract. Instead, the contract is partially or fully cancelled and the parties under the contract are no longer obligated to deliver or pay for the applicable quantities. Therefore, when the delivery of contract quantities is cancelled as a result of a force majeure event, we believe there is no tainting of the contract itself if the force majeure event meets all of the following criteria:

- It is not within the control of either party to the contract.
- It does not result in net settlement of the cancelled quantities.
- It relieves or eliminates the rights and obligations of the parties under the contract for the applicable quantities.

In addition, if all of these criteria are met, there would be no tainting of similarly designated contracts.

Application example — normal purchases and normal sales scope exception: Change in forecast

The following simplified example is provided to illustrate the application of the guidance on the normal purchases and normal sales scope exception when a reporting entity's forecast changes.

EXAMPLE 3-17

Application of the normal purchases and normal sales scope exception — natural gas contract

Ivy Power Producers (IPP) enters into a forward contract to purchase 10,000 MMBtus of natural gas per day from January 1, 2015 to December 31, 2015. It plans to use the natural gas at the Maple Generating Station. In April 2015, IPP takes delivery of the entire contractual volume of natural gas. However, not all of the purchased natural gas was used as the facility did not operate at full capacity due to a decrease in power prices. IPP resells 100,000 MMBtus of natural gas into the market.

Is the resale of the 100,000 MMBtus a tainting event?

Analysis

Even though IPP did not net settle the 100,000 MMBtus of natural gas (i.e., the total amount of natural gas was physically delivered), it is likely that the circumstance described above would be considered a tainting event. However, the specific facts and circumstances would need to be considered. For example, if the change was due to a specific event and did not result in a change in the business activities of IPP (e.g., the natural gas was not used because of an unusual or unforeseen plant outage), we would not expect this to cause a tainting issue. However, if IPP's forecast showed that the full quantity of natural gas would not be used in April 2015, the contract should not have been designated as a normal purchase because IPP did not need the full volume under the contract for its operations.

3.3.1.4 Documentation

ASC 815 does not specify the timing of documentation requirements for the normal purchases and normal sales designation. However, reporting entities making the election should maintain appropriate documentation to distinguish those contracts designated as normal purchases and normal sales. In accordance with ASC 815-10-15-38, failure to comply with the documentation requirements precludes application of the exception, even if the contract would otherwise qualify. ASC 815-10-15-37 specifies the minimum documentation requirements for a contract designated as a normal purchase or normal sale.

Excerpt from ASC 815-10-15-37

For contracts that qualify for the normal purchases and normal sales exception...the entity shall document the designation of the contract as a normal purchase or normal sale, including either of the following:

- a. For contracts that qualify for the normal purchases and normal sales exception under paragraph 815-10-15-41 or 815-10-15-42 through 15-44, the entity shall document the basis for concluding that it is probable that the contract will not settle net and will result in physical delivery.
- b. For contracts that qualify for the normal purchases and normal sales exception under paragraphs 815-10-15-45 through 15-51, the entity shall document the basis for concluding that the agreement meets the criteria in that paragraph, including the basis for concluding that the agreement is a capacity contract.

Specific factors to consider as required by ASC 815-10-15-37(a) and 15-37(b) are further discussed in UP 3.3.1.5. This section addresses the method and timing of designation as well as other matters to consider in developing a documentation policy.

Designation method

ASC 815-10-15-38 specifies that the documentation required to designate a contract as a normal purchase or normal sale can be applied to individual contracts or to groups of contracts. Designation of individual contracts may provide more flexibility; however, it also increases the documentation requirements.

Potential bases for global designation include chronology, time of year, and trading point. However, the global designation policy should be based on objectively determinable criteria with sufficient specificity such that there is no ambiguity in the classification of a particular contract. For example, a reporting entity may decide to group all of its on-peak purchase contracts for delivery in a certain quarter or the first set of sales (such as the first 250 megawatts purchased) in a certain month. A reporting entity that applies a global methodology of electing contracts for the normal purchases and normal sales scope exception should do so consistently for similar contracts.

The rationale a reporting entity uses in its grouping of contracts for purposes of designating the normal purchases and normal sales scope exception is important. The guidance stipulates that net settlement of a contract that was designated as a normal purchase or normal sale would call into question the reporting entity's designation of other contracts in the same group. In addition, net settlement of such contracts would also call into question the reporting entity's ability to designate similar contracts as normal purchases and normal sales in the future. See UP 3.3.1.3 *Subsequent impact of net settlement (Tainting)* for more information on the impact of contracts that are net settled on application of the normal purchases and normal sales scope exception.

Timing of election

Although application of the normal purchases and normal sales scope exception is elective, once made, the election is irrevocable.

Excerpt from ASC 815-10-15-39

The normal purchases and normal sales scope exception could effectively be interpreted as an election in all cases. However, once an entity documents compliance with the requirements of paragraphs 815-10-15-22 through 15-51, which could be done at the inception of the contract or at a later date, the entity is not permitted at a later date to change its election and treat the contract as a derivative instrument.

There is no specific requirement to perform the normal purchases and normal sales assessment prior to entering into a contract or to document the conclusions contemporaneously with execution of the contract. However, to support the reporting entity's accounting position, at a minimum the election of the normal purchases and normal sales scope exception should be documented prior to the end of the accounting period in which it is first applied (e.g., by March 31 for a contract designated in March).

If a reporting entity designates a contract subsequent to inception, the normal purchases and normal sales scope exception will apply as of the period of designation.

Question 3-20

What is the accounting for the carrying value of a contract that is designated under the normal purchases and normal sales scope exception on a date subsequent to the trade date of the contract?

PwC response

If a contract qualifies as a derivative and is designated as a normal purchase or normal sale subsequent to the contract execution date, the reporting entity will have an asset or liability on its balance sheet equal to the fair value of the contract on the date the election is made. After designation as a normal purchase or normal sale, the contract will no longer be recorded at fair value. The pre-existing fair value, however, will remain as an asset or liability and should be amortized into income over the remaining life of the contract. The carrying value of the contract is subject to impairment analysis to the extent it is recorded as an asset upon execution.

The accounting for the carrying value of the contract subsequent to election of the scope exception is similar to the subsequent accounting for the fair value of nonderivative contract assets recorded as part of a business combination. See UP 8.4.1 for further information.

Other documentation considerations

The guidance requires that the documentation of the designation as a normal purchase or normal sale include certain information, including management's basis for concluding that physical delivery is probable when electing the commodity forward exception, and that the contract meets all of the requirements for the power contract exception, if elected (see UP 3.3.1.5 for further information on these exceptions).

In addition, as part of the process of reassessing whether specific contracts continue to qualify for the normal purchases and normal sales scope exception each period, reporting entities should ensure that the documentation supporting the designation of the contract as a normal purchase or normal sale has been updated as applicable.

Question 3-21

Can the normal purchases and normal sales scope exception be elected for a contract that is not a derivative at inception but could potentially become one in the future (conditional designation)?

PwC response

Yes. Provided the normal purchases and normal sales criteria are met, a contract could be designated under the exception prior to the time it becomes a derivative. We believe the ability to conditionally designate a contract is reasonable in consideration of the guidance in ASC 815-10-55-84 through 55-89, which allows for conditional hedging designations. If a conditionally designated normal purchases and normal sales contract meets the definition of a derivative at a later date, it would be accounted for as a normal purchases and normal sales contract from the time the contract becomes a derivative. Absent such a designation, the reporting entity would be required to initially fair value the contract at the time the contract is determined to be a derivative.

ASC 815-10-15-3

If events occur after the inception or acquisition of a contract that cause the contract to meet the definition of a derivative instrument, then that contract shall be accounted for *at that later date* as a derivative instrument under this Subtopic unless one of the scope exceptions in this Subsection applies. (emphasis added)

ASC 815-10-25-2 provides additional guidance on the accounting at the time the contract becomes a derivative. However, if the normal purchases and normal sales scope exception has already been applied, then no recognition in earnings at the time the contract meets the definition of a derivative is required.

ASC 815-10-25-2

If a contract that did not meet the definition of a derivative instrument at acquisition by the entity meets the definition of a derivative instrument after acquisition by the entity, the contract shall be recognized immediately as either an asset or liability with the offsetting entry recorded in earnings.

From a practical perspective, often the reporting entity will not know the exact date a contract meets the definition of a derivative. As a result, the contract could meet the definition of a derivative prior to a contemporaneous election of the normal purchases and normal sales scope exception. A conditional designation avoids this issue and allows for continued accounting for the contract as an executory contract.

Reporting entities should be careful that the contracts that are conditionally designated under this scope exception do not result in net settlement. Net settlement of a conditionally designated contract would result in the specific contract no longer qualifying for the normal purchases and normal sales scope exception and could result in tainting of other designated contracts.

Question 3-22

Can an embedded derivative qualify for the normal purchases and normal sales scope exception?

PwC response

Yes. If a reporting entity would otherwise be required to separate an embedded derivative from a host contract, it may elect the normal purchases and normal sales scope exception for that embedded derivative if all the criteria for election are met. Once the embedded derivative is identified as an element that requires separate accounting, it is accounted for under ASC 815 as a separate unit of account. This includes the accounting, disclosures, and evaluation of scope exceptions. The embedded derivative would not require separation if the normal purchases and normal sales scope exception is elected.

3.3.1.5 *Types of contracts that may qualify for the normal purchases and normal sales scope exception*

ASC 815-10-15-40 through 15-51 describe the types of contracts that may qualify for the normal purchases and normal scope exception, as summarized in Figure 3-6.

Figure 3-6

Types of contracts that may be designated normal purchases or normal sales

Type of contract	Key considerations
Freestanding option contracts	<ul style="list-style-type: none"> □ Not eligible, except for the limited exception for power contracts as defined in ASC 815-10-15-45
Forward contracts (non-option-based)	<ul style="list-style-type: none"> □ Applies to forward contracts with no volumetric optionality □ Must be probable at inception and throughout the contractual period that physical delivery will occur □ Contracts subject to unplanned netting (i.e., book-out) are not eligible for this exception. See specific exception for power purchase or sale agreements subject to book-out below.

Type of contract	Key considerations
Forward contracts with optionality features	<ul style="list-style-type: none"> <li data-bbox="792 268 1469 352">□ Generally, contracts with volumetric optionality are not eligible for the normal purchases and normal sales scope exception <li data-bbox="792 373 1469 436">□ Limited exception for power contracts as defined in ASC 815-10-15-45 <li data-bbox="792 457 1469 541">□ Contracts with other types of optionality (e.g., market price) may be eligible for the exception if the criteria in ASC 815-10-15-42 through 15-43 are met
Power purchase or sale agreements	<ul style="list-style-type: none"> <li data-bbox="792 573 1469 699">□ A power purchase or sale agreement (forward, option, or a combination) is eligible for the scope exception if the contract meets the definition of a capacity contract <li data-bbox="792 720 1469 783">□ Specific to power contracts—other commodities are not eligible for this exception <li data-bbox="792 804 1469 825">□ Buyer and seller should meet certain requirements <li data-bbox="792 846 1469 919">□ The power contract exception may be applied even if the contract is subject to book-out, if all other requirements are met

The considerations for applying the normal purchases and normal sales scope exception to each of these types of contracts are discussed in the following sections.

Freestanding option contracts⁹

ASC 815-10-15-40

Option contracts that would require delivery of the related asset at an established price under the contract only if exercised are not eligible to qualify for the normal purchases and normal sales scope exception, except as indicated in paragraphs 815-10-15-45 through 15-51.

A contract with volumetric optionality is not eligible for the normal purchases and normal sales scope exception because it cannot be determined if it is “probable at inception and throughout the term of the individual contract that the contract will result in physical delivery.” Option contracts only contingently provide for such physical delivery (i.e., delivery is made only when the price of the item is above the strike price and the holder exercises the option).

In evaluating option contracts, the key factor that should be considered is whether the optionality impacts the quantity to be delivered under the contract. A volumetric option is not eligible for the normal purchases and normal sales scope exception, except in the case of certain qualifying power contracts. Contracts that contain

⁹ Guidance originally issued as DIG Issue C10, *Scope Exceptions: Can Option Contracts and Forward Contracts with Optionality Features Qualify for the Normal Purchases and Normal Sales Exception?*

optionality related only to price or other non-volumetric features would be eligible for the normal purchases and normal sales scope exception if the other required criteria are met.

Forward contracts (Non-option based)

ASC 815-10-15-41 states that the normal purchases and normal sales scope exception can be applied to forward contracts, which would include contracts for natural gas, coal, oil, and other commodities (hereinafter referred to as the commodity forward exception). One of the underlying principles of the commodity forward exception is that it applies to contracts for physical delivery. However, some commodity contracts may include implicit or explicit net settlement provisions (UP 3.2.3.1) or have a market mechanism that permits net settlement (UP 3.2.3.2). Because a contract with one of those features may not require physical delivery, it must be probable at inception and throughout the term of the contract that physical delivery of the commodity will occur in order for this type of contract to qualify.

Excerpt from ASC 815-10-15-41

Forward contracts are eligible to qualify for the normal purchases and normal sales scope exception. However, forward contracts that contain net settlement provisions as described in either paragraphs 815-10-15-100 through 15-109 or 815-10-15-110 through 15-118 are not eligible for the normal purchases and normal sales scope exception unless it is probable at inception and throughout the term of the individual contract that the contract will not settle net and will result in physical delivery.

As noted, contracts with net settlement provisions will not qualify for the normal purchases and normal sales scope exception unless it is probable that physical delivery will occur throughout the entire term of the contract. Net settlement of a particular contract would preclude application of the normal purchases and normal sales scope exception to that contract in the future and would call into question whether similar contracts qualify. See UP 3.3.1.3 *Subsequent impact of net settlement (Tainting)*.

Question 3-23

Can a power contract subject to book-out qualify for the normal purchases and normal sales scope exception in ASC 815-10-15-26(b)?

PwC response

Generally, no. Due to the structure of the power markets, there is an institutional convention that allows certain power contracts to be “booked out.” A book-out is an unplanned netting of a purchase and sale agreement by the contracting counterparties. Book-outs are an accepted practice in the industry and arise as multiple transactions routinely occur at the same point of delivery as utilities and power companies balance their loads. Counterparties will offset their schedules (i.e., book out) when they have a buy and a sell of the same quantities at the same point. Booking out results in no physical delivery under the contract and avoids transmission losses and administrative fees.

A book-out is a form of net settlement and the ability to book out precludes qualification for this exception, even if the reporting entity does not intend to and does not have a practice of booking out. As a result, most power contracts do not qualify for this exception. However, ASC 815 provides an exception for certain power contracts. See UP 3.3.1.5 *Certain power contracts* for further information on this exception.

Forward contracts that contain optionality¹⁰

Consistent with the guidance for freestanding options discussed in UP 3.3.1.5, ASC 815 precludes application of the normal purchases and normal sales scope exception to any forward contract that contains volumetric optionality (except certain power contracts).

Excerpt from ASC 815-10-15-42

Except for power purchase or sales agreements addressed in paragraphs 815-10-15-45 through 15-51, if an option component permits modification of the quantity of the assets to be delivered, the contract is not eligible for the normal purchases and normal sales scope exception, unless the option component permits the holder only to purchase or sell additional quantities at the market price at the date of delivery.

Therefore, a contract cannot qualify for the normal purchases and normal sales scope exception if its terms include volumetric optionality, unless the volumetric option is priced based on the market price at the time of delivery. Furthermore, ASC 815-10-55-26 specifically prohibits a reporting entity from bifurcating the forward component and the option component in a combined contract and then electing the normal purchases and normal sales scope exception for the forward component. However, a reporting entity may be able to avoid some of the accounting implications of this guidance as follows:

- *Separate forward and option contracts*

As discussed in ASC 815-10-55-27, instead of executing a single supply contract, a reporting entity could enter into two separate contracts: a forward contract for a specified quantity and an option contract for additional quantities whose purchase is conditional on the exercise of the option. The separate forward contract may then be eligible for the normal purchases and normal sales scope exception, provided all the criteria are met.

- *Requirements contracts*

A requirements contract specifies that the supplier will provide amounts equal to the purchaser's needs, with prohibition against resale. In some cases, the contract requires a certain level of minimum purchases (resulting in a derivative for the specified minimum amount). Any remaining fluctuation in quantity would not be

¹⁰ Guidance originally issued as DIG Issue C16, *Scope Exceptions: Applying the Normal Purchases and Normal Sales Exception to Contracts That Combine a Forward Contract and a Purchased Option Contract*.

included in the notional amount. In a requirements contract, the portion of the contract that is accounted for as a derivative would be eligible for designation under the normal purchases and normal sales scope exception, provided all the criteria are met. See UP 3.2.1.1 for further information on requirements contracts.

□ *Power contracts*

Power contracts may be eligible for the normal purchases and normal sales scope exception in accordance with ASC 815-10-15-45 through 15-51. See UP 3.3.1.5 *Certain power contracts* for further information.

Furthermore, once a volumetric option feature expires or has been exercised, it would no longer affect the evaluation.

Excerpt from ASC 815-10-15-43

If the optionality feature in the forward contract can modify the quantity of the asset to be delivered under the contract and that option feature has expired or has been completely exercised (even if delivery has not yet occurred), there is no longer any uncertainty as to the quantity to be delivered under the forward contract. Accordingly, following such expiration or exercise, the forward contract would be eligible for designation as a normal purchase or normal sale, provided that the other applicable conditions in this Subsection are met.

Therefore, if a contract includes a volumetric option, the reporting entity may reassess whether the contract qualifies for the normal purchases and normal sales scope exception upon exercise or expiration of the option. Once the option has expired, the contract no longer has any volumetric optionality and the reporting entity can determine whether the contract will result in physical delivery. See UP 3.3.1.4 *Timing of election* for the accounting when a contract is designated as normal subsequent to its inception.

Question 3-24

Can a contract that requires the sale of a fixed volume of natural gas with an embedded option for additional volumes at a price based on an index plus a fixed-price adjuster qualify for the normal purchases and normal sales scope exception?

PwC response

It depends. A contract that includes both a forward component and an option component can only qualify for the normal purchases and normal sales scope exception if the optional volumes are purchased or sold at market prices at the time of the delivery. Price adjustments to market should be carefully considered prior to concluding that the contract can qualify for the normal purchases and normal sales scope exception. For example, if the market price is adjusted to compensate for a customary fee or administrative costs that are typically incurred, then the contract may still be eligible for designation under the normal purchases and normal sales scope exception. However, if the differential is intended to reflect basis differences

due to the delivery location (e.g., the contract is priced on NYMEX Henry Hub but the delivery location is SoCal Border, a market hub for natural gas located in California), then the price differential may not be reflective of market at all delivery dates. In such cases, the contract would not qualify for this exception.

*Application examples – normal purchases and normal sales scope exception:
Contracts with volumetric optionality*

EXAMPLE 3-18

Application of the normal purchases and normal sales scope exception – contract with volumetric optionality

Assume the same facts as in Example 3-1: Ivy Power Producers agrees to purchase natural gas from Guava Gas Company for delivery to the Maple Generating Station. The contract has a maximum daily quantity (10,000 MMBtus per day). IPP is required to take or pay for at least 75% of the maximum daily quantity specified in the contract (i.e., 7,500 MMBtus per day) and may take additional amounts up to the maximum specified.

Does the contract qualify for the normal purchases and normal sales scope exception?

Analysis

As discussed in Example 3-1, this arrangement represents a forward contract for 7,500 MMBtus per day combined with an option contract for up to an additional 2,500 MMBtus per day. As a result of the volumetric optionality, the contract does not qualify for the normal purchases and normal sales scope exception in this fact pattern.

However, the contract may potentially qualify for accounting as a normal purchase in the following circumstances:

- The option component permits the holder only to purchase or sell additional quantities at the market price at the date of delivery (see ASC 815-10-15-42).
- The option feature is expired or has been completely exercised (even if delivery has not yet occurred) (see ASC 815-10-15-43).
- The contract is determined to be a requirements contract (because the volumetric optionality would not be included in the notional amount of the contract). See UP 3.2.1.1 for further information. See Example 3-19.

In such cases, the contract could qualify for the normal purchases and normal sales scope exception if all other requirements are met.

EXAMPLE 3-19**Application of the normal purchases and normal sales scope exception — requirements contract with volumetric optionality**

Assume the same facts as in Example 3-18, except that the contract specifies that the Guava Gas Company is to supply all of Ivy Power Producers' natural gas needs for the Maple Generating Station. In addition, IPP is required to take at least 7,500 MMBtus/day and may take additional amounts up to its maximum needs (total needs are expected to be around 10,000 MMBtus/day). The agreement explicitly states that all purchases under the contract must be used for generation at the Maple power plant and that resale is prohibited. This is the same fact pattern described in Example 3-2.

Does the contract qualify for the normal purchases and normal sales scope exception?

Analysis

As discussed in Example 3-2, this contract is a requirements contract with a notional amount of 7,500 MMBtus/day. The additional quantity above the required amount is not included in the notional because this is a requirements contract. Because the notional relates only to the forward component, the contract could qualify for the normal purchases and normal sales scope exception if all other requirements are met.

EXAMPLE 3-20**Application of the normal purchases and normal sales scope exception — natural gas contract**

Ivy Power Producers (IPP) enters into a forward contract with Guava Gas Company to purchase 10,000 MMBtus of natural gas per day for 3 years for use in the Maple Generating Station. In addition, the contract states that at the end of each year, the parties will cash settle for any difference between the contracted amount of natural gas and the amount of natural gas that was delivered. If the total natural gas delivered is greater than the contractual amount, IPP will pay the then-current market rate for the excess natural gas. However, if the natural gas delivered is less than the contractual amount, IPP will receive the difference between the then-current market rate and the fixed price.

Does the contract qualify for the normal purchases and normal sales scope exception?

Analysis

Although the contract has certain provisions that may result in financial settlement, the contract is eligible for the normal purchases and normal sales scope exception if IPP can assert that all contractual volumes will result in physical delivery. The contract is still eligible for the exception because the additional volumes are purchased at the then-current market price. If, however, at the end of any particular year, the contract is net settled because IPP did not take physical delivery of the full contractual amount of natural gas, then the contract will need to be recorded at fair

value. The net settlement would also call into question the designation of other similar contracts.

Certain power contracts¹¹

Due to unique characteristics in the electric power industry, particularly the fact that power cannot be readily stored in significant quantities, ASC 815 provides a specific normal purchases and normal sales scope exception for certain qualifying power contracts (herein referred to as the power contract exception). Guidance on application of the power contract exception is provided in ASC 815-10-15-45 through 15-51 as well as ASC 815-10-55-31.

This scope exception solely applies to power purchase and sales agreements and cannot be analogized to other commodities such as natural gas, crude oil, or fuel oil. This exception allows for power contracts that meet the specified criteria to qualify for application of the normal purchases and normal sales scope exception, even if the contract contains volumetric optionality or is subject to book-out (see Question 3-23). Contracts that are subject to book-out, whether through local operating protocols or as a result of the requirements of an independent system operator or regional transmission organization, should be evaluated under the power contract exception.

In determining whether a contract qualifies for this exception, there are certain criteria that should be met by all parties to the contract. There are also additional criteria applicable to contracts with volumetric optionality. Note that forward contracts that are not subject to unplanned netting also may be evaluated under ASC 815-10-15-41 (forward contracts exception) and are not required to meet the additional requirements of the power contracts exception.

Criteria for all qualifying contracts

Overall guidance on application of the power contracts exception is provided in ASC 815-10-15-45.

Excerpt from ASC 815-10-15-45

Notwithstanding the criteria in paragraphs 815-10-15-41 through 15-44, a power purchase or sales agreement (whether a forward contract, option contract, or a combination of both) that is a capacity contract for the purchase or sale of electricity also qualifies for the normal purchases and normal sales scope exception if all of the following applicable criteria are met.

¹¹ Guidance originally issued as DIG Issue C15, *Scope Exceptions: Normal Purchases and Normal Sales Exception for Certain Option-Type Contracts and Forward Contracts in Electricity* (DIG Issue C15) and in FAS 133, paragraph 58(b).

Definition from ASC 815-10-20

Capacity Contract: An agreement by an owner of capacity to sell the right to that capacity to another party so that it can satisfy its obligations. For example, in the electric industry, capacity (sometimes referred to as installed capacity) is the capability to deliver electric power to the electric transmission system of an operating control area.

While the standard specifies that the contract must be a capacity contract, we believe that the application of the power contracts exception is applicable for capacity contracts that include the physical delivery of power in the arrangement. To qualify for this exception, power contracts should be assessed to determine if the criteria set forth in ASC 815-10-15-45 are met. Figure 3-7 highlights the criteria applicable to each party to the contract.

Figure 3-7
Power contracts exception criteria

Criteria	Applicable to buyer	Applicable to seller
The terms of the contract require physical delivery of electricity. That is, the contract does not permit net settlement, as described in ASC 815-10-15-100 through 15-109. (ASC 815-10-15-45(a)(1))	Yes	Yes
The electricity that would be deliverable under the contract involves quantities that are expected to be used or sold by the reporting entity in the normal course of business. (ASC 815-10-15-45(b) and 15-45(c)(1))	Yes	Yes
The buyer of the electricity under the power purchase or sales agreement is an entity that meets both of the following criteria: (i) The entity is engaged in selling electricity to retail or wholesale customers; (ii) The entity is statutorily or otherwise contractually obligated to maintain sufficient capacity to meet electricity needs of its customer base. (ASC 815-10-15-45(c)(2))	Yes	Not applicable
The contracts are entered into to meet the buyer's obligation to maintain a sufficient capacity, including a reasonable reserve margin established by or based on a regulatory commission, local standards, regional reliability councils, or regional transmission organizations. (ASC 815-10-15-45(c)(3))	Yes	Not applicable

ASC 815-10-15-45 also includes criteria that are only applicable to contracts with volumetric optionality (see UP 3.3.1.5 *Certain power contracts*).

To qualify for the power contracts scope exception, a reporting entity should assess not only its own compliance with the requirements but also whether the contract counterparty meets the requirements. For example, the seller under the contract should consider whether the purchaser is buying to meet its obligation. To meet the requirement, it is not sufficient to only consider that the seller has capacity to support the contract. Therefore, to assist reporting entities in applying the guidance, PwC has developed interpretive guidance and specific criteria to consider in assessing whether the counterparty meets the relevant criteria. Key factors to consider are summarized in Figure 3-8.

Figure 3-8
Assessment of a counterparty in power purchase or sale agreements

Counterparty	Considerations
Buyer's assessment of seller	<ul style="list-style-type: none"> □ Seller's source of power does not necessarily have to be specified □ Buyer should have evidence (beyond the regulatory requirements to qualify as a "firm power forward") that seller has access to capacity at or near the delivery point (e.g., known generating capacity at or near the delivery point)
Seller's assessment of buyer	<ul style="list-style-type: none"> □ Seller has knowledge (including publicly available information) about buyer's existing load commitments at or near the delivery point □ Buyer's load commitments can include retail, wholesale, and certain contractual commitments □ Seller does not have to verify that the quantity being purchased, when added to existing generation capacity and other purchases, would exceed buyer's projected power needs □ There is a presumption (which can be overcome with appropriate evidence) that a sale to a non-load serving entity (e.g., power brokers and load serving entities with no load in the applicable area) would not qualify under this criterion.

The considerations in Figure 3-8 are further discussed below.

Buyer's evaluation

For the buyer to meet its requirement to evaluate the seller, it would not be necessary for the contract to specify the source of the energy. However, the buyer should have evidence (beyond the regulatory requirements to qualify as a "firm power forward") that the seller has access to capacity at or near the delivery point at the time the contract is designated as qualifying under the normal purchases and normal sales scope exception. In addition to the broad regulatory requirement, the buyer would have to consider evidence of the seller's existing capacity. This requirement could be met if any of the following conditions are present:

- The seller is known to have generating capacity at or near the delivery point
- The seller is selling to the buyer at a location where the seller has access to a power pool (e.g., PJM Interconnection, L.L.C., California Independent System Operator) that makes generating capacity available to all participants, in which case the buyer can assume such capacity because the power pool would, if necessary, provide it to the seller
- Other evidence is obtained that demonstrates that the seller has the available capacity through direct ownership of a generating plant or by contract

For example, if the seller is a power broker that does not have access to a pool, the buyer would have to obtain evidence supporting a conclusion that the seller has access to capacity at or near the delivery point (e.g., a long-term power purchase contract or tolling agreement) to back the contract. Similarly, such evidence would have to be obtained if the seller (or a sister company) is a known owner of generation but the delivery point in the contract is a location that cannot be served from its owned capacity.

Seller's evaluation

In assessing whether it has sufficient capacity to meet its commitment, the seller should consider its own existing generating assets plus firm capacity purchase contracts, and deduct existing native load requirements and any other existing power sales contracts. In other words, the seller cannot double count the same capacity (i.e., it cannot count existing capacity as both meeting its native load capacity requirements and at the same time backing a sales contract it wishes to designate as a normal sales contract).

In making this assessment, the seller may also consider power resources that it has available because it has access to a power pool that makes generating capacity available to all participants. Furthermore, the seller should meet this requirement on the date the contract is designated (i.e., a sales contract would not qualify if the seller intends to obtain the quantity through a future purchase, unless the future purchase will be from a power pool that makes generating capacity available to all participants, or if access to the power pool provides a back-up source to fulfill the delivery obligation).

In assessing whether the buyer needs the energy for use or sale, the seller could assess the buyer's ability based on knowledge (including publicly available information) of the buyer's existing load commitments (i.e., the seller could presume the buyer is purchasing under the contract to meet its load requirements if the buyer is known to have such a requirement at or near the delivery point under the contract). Load requirements would include retail and wholesale requirements and certain contractual requirements. In assessing whether this criterion is met, the seller would not have to verify whether the specific quantity being purchased, when added to the buyer's existing generating capacity and other purchases by the buyer, would exceed the buyer's projected needs.

There is a presumption that a sale to a non-load serving entity (including a power broker or a load serving utility with no load at or near the delivery point) would not qualify under this criterion. However, that presumption could be overcome if evidence is obtained that demonstrates that the ultimate use of the power will be to fulfill a load serving requirement (e.g., of a customer of the non-load serving purchaser). Such evidence can be assumed to exist if the purchaser is a sister company of a load serving entity that has a load requirement at or near the delivery point (see further discussion below).

Consolidated groups

Reporting entities that are members of a consolidated group should apply the criteria above based on facts existing at the consolidated level. For example, if a power broker subsidiary buys power to sell to a load serving sister company, the broker subsidiary's purchase transaction would (1) meet the purchaser criterion that the purchaser has an obligation to maintain sufficient capacity and (2) qualify as a capacity contract (assuming the other criteria are met) at both the subsidiary and consolidated levels.

Similarly, in applying the criteria, reporting entities may assume certain facts about intercompany relationships with respect to a counterparty's consolidated group, if the circumstances support such an assumption. For example, a sale to the power broker subsidiary of a consolidated group that includes a load serving entity would meet the seller criterion if the purchase is at a location where the load serving sister company is known to have a load requirement. On the other hand, absent further evidence of the intended use of the power, that seller criterion would not be met in a sale to a power broker subsidiary of a consolidated group that includes a load serving entity if the delivery point is not at or near the load requirement of the sister company.

Option contracts

In general, contracts with volumetric optionality cannot qualify for the normal purchases and normal sales scope exception. However, ASC 815 contains a special exemption for certain qualifying power contracts with volumetric optionality because of the unique considerations related to power as described above. In accordance with ASC 815-10-15-45, in addition to the criteria applicable to all contracts discussed in UP 3.3.1.5 *Certain power contracts*, for option contracts, physical delivery is required if the option is exercised. Furthermore, option contracts should be assessed using the additional criteria provided by ASC 815-10-55-31. This guidance differentiates between qualifying option contracts (i.e., capacity contracts) and financial options on electricity. Factors to consider in assessing whether a contract is a capacity contract as outlined in ASC 815-10-55-31 are summarized in Figure 3-9.

Figure 3-9
Distinguishing between capacity contracts and financial option contracts

Characteristic	Capacity contract	Financial option contract
Source of power	Usually specifies the plant or group of plants	No reference is made to the source of power
Price	Includes pricing terms to compensate plant operator for variable operations and maintenance costs during production period	Structured based on the forward price of power
Quantity	Based on individual needs of parties to the agreement	Standard market amounts
Delivery	Usually one or a group of physical delivery locations; seller or buyer specific location	Major market hub (liquid hub)
Operations	Certain operational criteria are usually specified (e.g., heat rate of facility)	No criteria specified
Transmission	May include interconnection or physical transmission requirements	No requirements specified
Outages	May specify jointly agreed-to plant outages and may include penalties for unexpected outages	Not plant specific; no penalties pertaining to a specific plant
Default	Usually based on a refund of the capacity payment; default provision usually tied to the expected facility	Damages based on market liquidating damages
Duration	Term is usually long (one year or more)	Term reflects liquid market period (18 to 24 months in the guidance)

In determining whether a contract with volumetric optionality qualifies for the power contract exception, a reporting entity should consider all relevant contract characteristics. Not all of the characteristics in ASC 815-10-55-31 need to be met to conclude that the contract qualifies as a capacity contract; however, the conclusion should be based on the predominant characteristics of the contract. Consideration of the purpose for executing the agreement may also be helpful in performing this assessment.

Application examples — normal purchases and normal sales scope exception: option contracts

The following simplified examples are provided to illustrate the application of the power contracts exception to option contracts, specifically considering the evaluation under ASC 815-10-55-31. For purposes of these examples, assume all of the other relevant criteria for application of the normal purchases and normal sales scope exception are met.

EXAMPLE 3-21

Application of the normal purchases and normal sales scope exception — option contract

Ivy Power Producers (IPP) enters into an agreement to sell electric energy to Rosemary Electric & Gas Company (REG). The contract states that REG has an option to take an hourly quantity of 100 MWs during on-peak hours for the month of August 2015. Energy will be delivered from the Maple Generating Station for an initial option premium plus start-up fees, variable operating and maintenance fees, and a natural gas charge based on a heat rate of 7.0. The delivery location is at the power plant. REG has retail customer load commitments near the Maple Generating Station.

Is the contract eligible for the power contract exception?

Analysis

This contract exhibits a significant number of the characteristics of a capacity contract including specified plant location and delivery point, as well as pricing based on plant operations. Although the contract is short-term (one month), it would be eligible for the power contract exception because the predominant characteristics of the contract meet the capacity contract criteria.

If, however, no plant is specified, the pricing is based on the forward price curve for power, and delivery is to a liquid trading point, the contract would predominantly have characteristics of an option contract and it would not be eligible for the normal purchases and normal sales scope exception.

EXAMPLE 3-22

Application of the normal purchases and normal sales scope exception — option contract

Ivy Power Producers (IPP) enters into a contract with Rosemary Electric & Gas Company (REG) to sell electric energy from the Maple Generating Station. The contract term is five years. REG has an option to take up to an hourly amount of 100 MWs during on-peak hours. The contract price includes a start-up fee, variable operating and maintenance fee, and a natural gas charge based on a 7.0 heat rate. The delivery location is a liquid trading location for power. The contract specifies the timing of plant outages. REG has retail load commitments located near the Maple power plant.

Does the contract qualify for the normal purchases and normal sales scope exception?

Analysis

Although this contract includes some characteristics of a financial option (e.g., delivery at a liquid trading point), the predominant characteristics are that of a capacity contract. Therefore, the contract is eligible for the normal purchases and normal sales scope exception. This would likely still be the case even if the pricing was market-based. However, assessing whether a contract is a capacity contract requires judgment and all relevant criteria should be considered in the assessment.

3.3.2 *Certain contracts not traded on an exchange*

In addition to the normal purchases and normal sales scope exception, ASC 815 includes certain scope exceptions for contracts that are not exchange-traded. Unlike the normal purchases and normal sales scope exception, these exceptions are not elective. Therefore, if a contract meets the criteria for one of the exceptions, derivative accounting is not applied.

The scope exceptions described in ASC 815-10-15-59 through 15-62 apply in part if the underlying on which the settlement is based is any one of:

- A climatic or geological variable or other physical variable
- The price or value of a nonfinancial asset that is not readily convertible to cash
- The price or value of a nonfinancial liability if the liability does not require delivery of an asset that is readily convertible to cash
- Specified volumes of sales or service revenues of one of the parties to the contract

The scope exceptions that commonly apply to utilities and power companies are further discussed below.

Question 3-25

Can the scope exception related to contracts not traded on an exchange be applied if a contract contains more than one variable?

PwC response

It depends. Some contracts may contain both a financial variable and a variable that qualifies for one of the scope exceptions in ASC 815-10-15-59 through 15-62. In accordance with ASC 815-10-15-60, in such cases, a reporting entity needs to look to the predominant characteristics of the contract. If the underlyings in the contract, when combined, behave in a manner that is highly correlated to any of the variables that do not qualify for a scope exception, then the contract would be subject to the requirements of the derivatives guidance.

3.3.2.1 *Climatic, geological, or other physical variables*

ASC 815-10-15-59 provides a specific scope exception for non-exchange-traded contracts with an underlying based on a climatic or geological variable.

Excerpt from ASC 815-10-15-59(a)

A climatic or geological variable or other physical variable. Climatic, geological, and other physical variables include things like the number of inches of rainfall or snow in a particular area and the severity of an earthquake as measured by the Richter scale.

To qualify for this exception, the contract cannot be exchange-traded and the underlying must be a variable related to weather or other geological or physical variable. Physical variables are items such as temperature, wind speed, or other weather-related factors. For example, a power contract with pricing based on cooling-degree days would meet the exception. Market-related volumes of a commodity (e.g., the total volume on NYMEX) would not qualify for this exception because the volume on an exchange or other market is not a physical variable. As noted above, ASC 815-10-55-135 contains examples of how to apply this exception.

Derivative accounting, however, would apply to weather-related contracts traded on an exchange. In addition, ASC 815-45 provides specific nonderivative guidance on accounting for non-exchange-traded weather derivatives (note that the guidance refers to this type of contract as a derivative although it does not meet the accounting definition). The guidance includes two different accounting models, depending on the reporting entity's purpose for executing the contracts. See UP 3.6.8 and ASC 815-45 for further information on the accounting models for non-exchange-traded weather derivatives.

3.3.2.2 *Specified volumes of sales or service revenues*

ASC 815-10-15-59 also provides a scope exception for non-exchange-traded contracts with an underlying based on specified volumes of sales or service revenues of one of the parties to the contract.

ASC 815-10-15-59(d)

Specified volumes of sales or service revenues of one of the parties to the contract. (This scope exception applies to contracts with settlements based on the volume of items sold or services rendered, for example, royalty agreements. This scope exception does not apply to contracts based on changes in sales or revenues due to changes in market prices.)

This exception applies only when settlement may be affected by changes in the volume of sales, not by changes in market price. This exception may also be extended to net income or earnings before interest, taxes, depreciation and amortization, unless the income measure is due predominantly to fair value movements. As an example, a contract issued by a reporting entity to pay a counterparty 3% of its net sales of natural gas would not be subject to the requirements of ASC 815. Furthermore,

because this guidance is not intended to apply to contracts with settlements based on changes that are due principally to changes in market prices, a contract to pay the counterparty a 3% price increase in the price of natural gas would not qualify for the exception.

Question 3-26

Can the sales or service revenue exception be applied to contracts that settle based on a combination of volume and market price changes?

PwC response

Yes. Based on discussions with the FASB staff, we understand that the phrase “changes in sales or revenues due to changes in market prices” is not intended to preclude royalty agreements wherein the payment is based on changes in sales or revenues due to changes in market prices, when those changes are applied to the volume of items sold or services rendered. We understand from the staff that the intention of the FASB was to prohibit applying the scope exception to (1) contracts that used as their sole variable the change in sales or revenues due to changes in market price, and (2) contracts containing variables based on the change in market prices and a trivial change in the number of units.

As a result, if the pricing of the contract incorporates both market price and changes in units, the contract would still meet the conditions for the scope exception.

Application example — sales or services revenue scope exception

The following simplified example is provided to illustrate the application of the guidance of the sales or services revenue scope exception.

EXAMPLE 3-23

Application of the sales or service revenues scope exception — power contract

Ivy Power Producers (IPP) enters into a power sales agreement with Rosemary Electric & Gas Company (REG) to be serviced from the Maple Generating Station. The pricing in the contract comprises a fixed capacity payment, along with a pass-through of natural gas costs. In addition, the monthly payment will be adjusted by an imputed net revenue amount that is calculated based on the difference between market power prices and the imputed variable energy cost. Therefore, monthly settlements are in effect based on the difference between a specified net revenue amount and actual revenue generated by the Maple power plant.

Should the arrangement be accounted for as a derivative?

Analysis

The contract meets the definition of a derivative, but IPP would then need to consider whether the contract meets the scope exception in ASC 815-10-15-59(d). The contract inherently includes an element of market pricing because the Maple power plant will

not dispatch if the cost of production is greater than the market price of power (given the imputed net revenue formula). In addition, the payout formula incorporates the market price of fuel, the market price of power, changes in the market heat rate, and the availability of the plant. As a result, monthly settlement is based on both the volume of sales from the plant and the market price of power.

The pricing formula in the contract is analogous to the royalty payment discussed above in Question 3-26, in which revenues are changing due to changes in market prices applied to the volume of items sold. Similar to the royalty agreement, settlement of this contract is based on sales, which are determined based on market price multiplied by volumes sold and incorporates both market prices and plant-specific elements. Therefore, consistent with the conclusion in Question 3-26, this contract qualifies for the scope exception because it settles based on a combination of market prices and other elements that are unrelated to the market.

3.4 *Embedded derivatives*

Certain contracts that do not meet the definition of a derivative in their entirety may contain pricing elements, other provisions, or components that are embedded derivatives. For example, utilities and power companies routinely enter into compound contracts for the sale or purchase of multiple products (such as energy, capacity, and renewable energy credits). As further discussed in UP 1, the accounting guidance provides a logical approach for the evaluation of this type of contract. A contract that is not a derivative in its entirety should be assessed to determine if it includes certain components that require separation and accounting as derivatives. The following section discusses the key items to consider in evaluating potential embedded derivatives in a commodity agreement. Key terms used in this section are described in Figure 3-10.

Figure 3-10
Embedded derivative-related terms

Term	Definition
Embedded derivative (ASC 815-10-20)	Implicit or explicit terms that affect some or all of the cash flows or the value of other exchanges required by a contract in a manner similar to a derivative instrument.
Hybrid instrument (ASC 815-10-20)	A contract that embodies both an embedded derivative and a host contract.
Host contract	The base financial instrument or other contract, excluding the embedded derivative. Host contract is not explicitly defined in ASC 815.

See DH 3 for further information on identifying and accounting for embedded derivatives in general. This section focuses on matters of particular interest in the evaluation of common commodity contracts.

Question 3-27

Should a reporting entity perform an embedded derivative analysis on a contract that is being accounted for under the normal purchases and normal sales scope exception?

PwC response

No. ASC 815-15-15-4 states that a contract that meets the definition of a derivative in its entirety but qualifies for the normal purchases and normal sales scope exception should not be assessed for embedded derivatives. See UP 3.3.1 for information on how to evaluate whether a contract qualifies for the normal purchases and normal sales scope exception.

3.4.1 *Assessing embedded versus freestanding elements*

Prior to assessing whether the contract is a derivative or includes any embedded derivatives, a reporting entity should consider whether there are any elements of the contract that are freestanding and should thus be accounted for separately. ASC 815 may still apply under either circumstance, but the application would be different. A freestanding financial instrument is defined in ASC 815.

Definition from ASC 815-10-20

Freestanding Contract: A freestanding contract is entered into either:

- a. Separate and apart from any of the entity's other financial instruments or equity transactions
- b. In conjunction with some other transaction and is legally detachable and separately exercisable.

Therefore, although a derivative instrument may be written into the same contract as another instrument (e.g., in a power contract), it is considered embedded only if it cannot be legally separated from the host contract and transferred to a third party. In contrast, features that are written in the same contract, but that may be legally detached and separately exercised would be considered attached, freestanding derivatives rather than embedded derivatives by both the writer and the holder. These freestanding derivatives would be accounted for separately, eliminating any need to evaluate them under the ASC 815 guidance on embedded derivatives.

This section addresses embedded derivatives and does not further discuss the accounting for freestanding instruments. See DH 3.1.1.1 for further information on evaluating whether an instrument is freestanding or embedded.

3.4.2 **Framework for evaluating the separation of embedded derivatives from the host contract**

In accordance with ASC 815-15-25-1, a derivative that is embedded in a nonderivative host is separated from the host and accounted for as a derivative only if *all* of the following criteria are met:

Excerpt from ASC 815-15-25-1

- a. The economic characteristics and risks of the embedded derivative are not clearly and closely related to the economic characteristics and risks of the host contract.
- b. The hybrid instrument is not remeasured at fair value under otherwise applicable generally accepted accounting principles (GAAP) with changes in fair value reported in earnings as they occur.
- c. A separate instrument with the same terms as the embedded derivative would, pursuant to Section 815-10-15, be a derivative instrument subject to the requirements of this Subtopic.

Factors to consider in applying these criteria are summarized in this section.

ASC 815-15-25-1(a) — is the potential embedded derivative clearly and closely related to the host contract?

The reporting entity needs to evaluate whether the economic characteristics and risks of the embedded derivative are clearly and closely related to the host contract. This evaluation is performed only once at the time the hybrid instrument is originated or acquired and should be performed separately for any potential embedded derivative. Typically, this evaluation is one of the most judgmental issues in determining whether bifurcation of the hybrid contract is required. UP 3.4.3 provides additional guidance for applying the clearly and closely related criterion to a commodity contract.

ASC 815-15-25-1(b) — is the contract carried at fair value in its entirety?

In assessing commodity contracts to determine whether they contain embedded derivatives that require separation, the reporting entity should assess whether the contract is carried at fair value in its entirety. If so, no further evaluation of potential embedded derivatives is required because the value of any embedded derivative should be incorporated in the overall valuation of the instrument. For example, a pricing feature that is unrelated to natural gas prices in a natural gas option contract accounted for as a derivative would not require separate accounting because the impact of the pricing feature is incorporated into the fair value of the overall option.

ASC 815-15-25-1(c) — would the potential embedded derivative meet the definition of a derivative on a stand-alone basis?

The reporting entity should evaluate whether the separate product, component, or feature would be a derivative on a stand-alone basis. See UP 3.2 for further information on the definition of a derivative and UP 3.6 for considerations in

evaluating specific types of commodity contracts. If the potential embedded derivative would not meet the definition of a derivative, no further analysis is required.

Does a scope exception apply?

If all of the criteria are met, the reporting entity would separate and account for the embedded derivative at fair value. However, prior to separation of the embedded derivative, the reporting entity should consider whether one of the exceptions to ASC 815 applies. If an exception applies, and is elected (if applicable), no separation is required. See UP 3.3 for further information on ASC 815 scope exceptions applicable to commodity derivative contracts.

3.4.2.1 *Considering multiple embedded derivatives*

The bifurcation analysis for a hybrid instrument often becomes increasingly challenging when it involves more than one embedded derivative. For example, a power purchase agreement may include features related to natural gas and power, which would both be derivatives on a stand-alone basis. When there are multiple embedded derivatives, the accounting should generally follow the guidance for compound derivatives in ASC 815-15-25-7 through 25-10.

See DH 3.3.3 for information on factors to consider when a contract includes more than one embedded derivative. See DH 3.7 for information on other accounting considerations for hybrid instruments, including discussion of the method for allocating basis between the host and a separated embedded derivative.

3.4.3 *Evaluating whether the potential embedded derivative is clearly and closely related to the host contract in a power purchase agreement*

Utilities and power companies often enter into power purchase or other agreements that include multiple products and/or services. For example, a contract may require the delivery of capacity, energy, and other items such as ancillary services or renewable energy credits. Typically, this type of contract does not meet the net settlement criterion in its entirety; therefore, further evaluation under the embedded derivative guidance is required. The evaluation of whether the products are clearly and closely related is a key question in the analysis.

In accordance with ASC 815-15-25-1, the determination of whether the embedded derivative is clearly and closely related to the host contract should be based on an analysis of economic characteristics and risks of the potential embedded derivative and host contract. Said differently, the clearly and closely related criterion considers whether the attributes of the derivative behave in a manner similar to the attributes of the host contract. The economic characteristics and risks are generally measured by reference to the cost or market value of the derivative and host.

In evaluating the application of clearly and closely related to a typical power purchase agreement, in general, we believe that separate products delivered in a single contract will not qualify as clearly and closely related (and thus further evaluation of whether the embedded derivative should be separated is required). This conclusion is based on the following primary factors:

□ *Separate products*

The concept of clearly and closely related in ASC 815-15 is focused on pricing features that change the cash flows of an arrangement and are expected to settle concurrently with settlement of the host contract. The ASC 815-15 guidance generally does not address contracts with multiple products or services. However, the risks and characteristics of a contract with multiple products or services that have different deliverables and settlement dates (e.g., timing of delivery of energy may not coincide with delivery of ancillary services or renewable energy credits) are not analogous to a contract with cash flow variations due to pricing features. Furthermore, for contracts with more than one deliverable (e.g., debt and equity, such as convertible debt) the embedded derivative typically is not clearly and closely related.

In a power purchase agreement containing multiple products, the buyer is paying for delivery of more than one item. Although the prices of the products in the contract may be interrelated (i.e., there could be some benefit by bundling the products into one contract as compared to stand-alone selling prices), the price of one product does not represent a price adjustment but instead represents a payment for a different deliverable.

□ *Periodic settlement*

A contract for more than one physically delivered product requires settlement (payment) for each of those products on a periodic basis. Each product represents a different cash flow under the contract and the settlement of one product does not result in settlement of the remaining products or obligations under the contract. ASC 815-15-25-41 provides an example of call and put options that do not accelerate the repayment of principal on a debt instrument but rather force a cash settlement that is equal to the price of the option at the date of exercise. The guidance in that paragraph states that the option, which has an independent settlement feature, would not be considered clearly and closely related to the debt host.

□ *Nonfinancial products*

ASC 815 provides limited guidance on how to perform this analysis for nonfinancial contracts; almost all of the application examples in ASC 815 pertain to financial hybrid instruments. In discussing one of the few nonfinancial hybrid examples, the response to DIG Issue B14, *Embedded Derivatives: Purchase Contracts with a Selling Price Subject to a Cap and a Floor* (DIG Issue B14), states, in part:

However, when deciding whether the economic characteristics and risks of the embedded derivative are clearly and closely related to the host contract for other nonfinancial hybrid contracts, it may not be appropriate to analogize to the guidance in paragraph 61 [now ASC 815-15-25-23 to 25-51]. The guidance in paragraph 61 is not meant to address every possible feature that may be included in a hybrid instrument but, instead, that paragraph covers common features present in financial hybrid contracts.

The DIG Issue B14 response indicates that, in general, the guidance provided on clearly and closely related in ASC 815 is applicable for financial hybrid contracts but not necessarily for nonfinancial hybrid contracts.

Based on these factors, we believe that multiple deliverables in a single contract are usually not clearly and closely related to the nonderivative host contract; therefore, further evaluation is required to determine if separation is required from the host contract (see UP 3.4.2). See further discussion of the application of the embedded derivative guidance to power contracts in Question 3-30 and the simplified examples that follow.

Question 3-28

How does the interpretation of clearly and closely related for embedded derivatives relate to the clearly and closely related criterion applied in the normal purchases and normal sales scope exception?

PwC response

ASC 815-10-15-30 through 15-34 establish a qualitative and quantitative approach for assessing whether a pricing feature is clearly and closely related in application of the normal purchases and normal sales scope exception. However, it also clarifies that the phrase conveys a different meaning than in the embedded derivative analysis.

Excerpt from ASC 815-10-15-31

The phrase *not clearly and closely related*...with respect to the normal purchases and normal sales scope exception is used to convey a different meaning than in paragraphs 815-15-25-1(a) and 815-15-25-16 through 25-51 with respect to the relationship between an embedded derivative and the host contract in which it is embedded.

In general, the normal purchases and normal sales scope exception establishes a more structured approach compared to the analysis performed in the embedded derivative evaluation. Specifically, the clearly and closely related analysis for purposes of applying the normal purchases and normal sales scope exception requires a qualitative and quantitative analysis of pricing features within the contract. To apply the exception, at contract inception the price adjustment should be expected to impact the price in a manner comparable to the outcome that would be obtained if, at each delivery date, the parties were to reprice the contract under then-existing conditions. In contrast the analysis of potential embedded derivatives does not require explicit comparison of the pricing but instead focuses on the overall economic risks and characteristics of the potential embedded derivative and the host.

See UP 3.3.1 for further discussion of the normal purchases and normal sales scope exception, including application of the exception to embedded derivatives.

Question 3-29

How is the host contract determined when assessing a hybrid contract?

PwC response

Identification of the host contract is a key question when determining whether a hybrid instrument requires bifurcation. There is little specific guidance on the identification of the host and we are aware that different methodologies are discussed. For example, some believe that the host contract should represent the “predominant characteristic(s)” within the hybrid, while others look to separate the derivative and nonderivative elements.

The Basis for Conclusions of FAS 133 discusses some of the FASB’s considerations in developing the hybrid approach. The FASB considered evaluating potential embedded derivatives based on predominant characteristics or yield, but concluded that those approaches would scope in instruments that were not the intent of the guidance and may not be operational. The FASB also initially considered requiring that the entire instrument be measured at fair value when a contract included both derivative and nonderivative elements. However, the FASB decided to only require the embedded derivative to be measured at fair value, except in limited circumstances, such as when the embedded derivative cannot be reliably identified and measured. The FASB believed that this approach was most consistent with the objective of measuring derivative instruments at fair value.

In evaluating the appropriate accounting, we further consider the guidance of ASC 815-15-05-1.

Excerpt from ASC 815-15-05-1

The effect of embedding a derivative instrument in another type of contract (the host contract) is that some or all of the cash flows or other exchanges that otherwise would be required by the host contract, whether unconditional or contingent on the occurrence of a specified event, will be modified based on one or more underlyings.

We also consider the accounting for the host contract discussed in ASC 815-15-25-54.

ASC 815-15-25-54

If an embedded derivative is separated from its host contract, the host contract shall be accounted for based on GAAP applicable to instruments of that type that do not contain embedded derivatives.

Considering the FASB’s objectives and related guidance, we believe the appropriate approach for determining the host contract is to identify those elements (cash flows) of a contract that meet the definition of a derivative separately from the nonderivative elements (cash flows) of the contract. Any nonderivative elements should be considered together as a single host contract and the potential derivative elements

should be evaluated for separation from the single host contract. Because the host contract follows other applicable U.S. GAAP, we do not believe any of the derivative elements can be the host contract. This approach is consistent with the FASB's overall objectives of measuring only derivative elements at fair value.

Question 3-30

Is energy and capacity considered clearly and closely related for purposes of assessing whether a hybrid contains an embedded derivative?

PwC response

Generally, no. As described above, we believe that the clearly and closely related exception for embedded derivatives was not intended to apply to contracts with separate products and deliverables with different pricing and settlements. Therefore, when evaluating capacity and energy combined in the same contract, we generally believe that they are not clearly and closely related (with a limited exception if these products are bundled in the area of the United States where they are being transacted).

Some may hold an alternative view that energy and capacity, or other products that could be combined in a power purchase agreement, should be subject to a quantitative and/or qualitative evaluation when performing the clearly and closely related analysis. Because of the nature of the markets (e.g., pricing of the products is sometimes correlated with each other), the source of the products (e.g., energy and capacity originating from the same plant or location), or the interrelationship within the contract (e.g., default provisions, pricing), proponents of this view believe that a clearly and closely related conclusion could be reached based on this type of analysis.

However, the intent (and examples that demonstrate the objective) of the ASC 815 guidance on clearly and closely related is to provide reporting entities with a practical accommodation for prepayment, pricing, and other features that modify the cash flows of a host contract; it is not to combine different products within the same contract. Therefore, we believe that separate deliverables under a contract are generally not clearly and closely related when the contract includes separate performance obligations, separate pricing, or multiple settlement dates for the products. In many cases, the energy portion within these contracts meets the definition of a derivative and so separate accounting for the energy and capacity portions of the contract would result.

3.4.3.1 Application examples — embedded derivative evaluation

The following simplified examples are provided to illustrate the evaluation of whether a contract contains an embedded derivative that requires separation.

EXAMPLE 3-24**Embedded derivative analysis – power purchase agreement**

On May 10, 2015, Ivy Power Producers (IPP) enters into a one-year agreement to sell an hourly amount of 100 MWs of capacity and energy, during on-peak hours, to Rosemary Electric & Gas Company (REG). The contract includes a capacity fee as well as separate charges for energy, start-up, and other ancillary charges.

REG operates in a market where energy and capacity are sold as separate products and there is no spot market for bundled energy and capacity. Furthermore, although there is bilateral activity in capacity, there is no active spot market and stand-alone physical capacity contracts do not meet the definition of a derivative instrument.

Does the arrangement contain an embedded derivative?

Analysis

The contract is not a derivative in its entirety because it does not meet the criteria of net settlement. The results of the analysis of potential embedded derivatives are summarized below.

ASC 815 criteria	Capacity	Energy
Economic characteristics of the embedded are not clearly and closely related to the host	Not applicable. Capacity is not a derivative on a stand-alone basis and would not be accounted for as a derivative. The capacity component is determined to be the host contract.	Met. The energy is not clearly and closely related to the capacity.
Hybrid instrument is not remeasured at fair value under otherwise applicable U.S. GAAP	Met. The power purchase agreement is not measured in its entirety at fair value under other applicable U.S. GAAP.	Met. The power purchase agreement is not measured in its entirety at fair value under other applicable U.S. GAAP.
A separate instrument with the same terms as the embedded derivative would be a derivative instrument subject to ASC 815	Not met. There is no active spot market for capacity and a stand-alone capacity contract would not be accounted for as a derivative in this market.	Met. There is an active spot market for power and management concludes that a stand-alone contract with the same terms would be accounted for as a derivative. If the normal purchases and normal sales scope exception is elected, the power component would not require separation.

In evaluating the clearly and closely related criterion, the energy is not clearly and closely related to the capacity given it is a separate deliverable with separate settlement dates. Furthermore, the delivery of energy does not adjust the cash flows related to capacity. Consistent with the discussion in UP 3.4.3, we believe that separate products combined in the same contract would generally not qualify as clearly and closely related to the host contract. As a result, in this example, the energy component should be separated from the capacity and accounted for as a derivative instrument, unless the energy component of the contract qualifies and the party elects the normal purchases and normal sales scope exception. The start-up and other ancillary costs would also not qualify as an embedded derivative under a similar analysis because these features, when present within a separate instrument, would not meet the definition of a derivative.

In addition, the analysis would not change even if the products were priced together within the contract (i.e., one bundled fixed price for both the energy and capacity). The contract as a whole would still not meet the net settlement criterion (i.e., there are no active spot markets for the bundled contract of energy and capacity) and evaluation of the separate capacity and energy components would be required. The bundled pricing would not change the evaluation completed as outlined above. See UP 1 and DH 3.7.1 for information on allocating fair value to a derivative that is separated from the host contract.

Question 3-31

Would a fully prepaid commodity agreement contain an embedded derivative that would require separation from the host?

PwC response

Generally yes. A fully prepaid commodity agreement would not meet the definition of a derivative instrument as the full amount of the agreement has already been paid and as such, the contract has an initial net investment. As a result, an entity should consider whether the agreement contains an embedded derivative that would require separate accounting. The prepayment of the commodity for the full term of the agreement would represent a financing or loan and thus the prepaid commodity agreement would be considered a debt host contract. However, the loan is being repaid through the delivery of a commodity (e.g., natural gas or crude oil) and therefore the interest rate on the loan is effectively tied to the price of the commodity. As such, the economic characteristics and risks of the potential embedded derivative (e.g., natural gas or crude oil pricing) are not clearly and closely related to those of the host loan contract (i.e., interest rates). The embedded derivative would require separation from the debt host and should be accounted for at fair value, unless the contract qualifies for and is designated under the normal purchases and normal sales scope exception.

Question 3-32

Would a contract that has an index relating to the transportation of the commodity be considered clearly and closely related?

PwC response

It depends. The clearly and closely related criterion considers whether the attributes of the derivative behave in a manner similar to the attributes of the host contract. One way the economic characteristics and risks can be measured is by reference to the cost of the derivative and host. As a result, if the index included in the pricing of the commodity is based on the cost to produce the commodity, the index would still be considered to be clearly and closely related as long as there is no leverage introduced in the agreement. For example, if a contract to purchase coal includes a gasoline price index that represents the transportation cost of moving the coal from the coal mine to the market, the gasoline price index would not require bifurcation if it can be demonstrated that the index represents the transportation cost of taking the coal to the market and does not introduce any extraneous impact from changes in gasoline prices or leverage. Similarly, for a biomass facility that burns wood for fuel and has a pricing component tied to diesel, we would deem a potential embedded derivative tied to the price of diesel to be clearly and closely related to the host contract to purchase power. This is because diesel is a key component of the price of the transportation to get the wood to the delivery location. In contrast, a host supply contract for the purchase of natural gas, with pricing based on the Consumer Price Index, would likely not capture the overall economic risk of natural gas price changes to enable application of the clearly and closely related criteria.

EXAMPLE 3-25**Embedded derivative analysis — coal contract with price inflation**

Ivy Power Producers (IPP) enters into a coal purchase contract that has terms requiring delivery of 100 tons of coal per week for 5 years with initial pricing fixed at \$90 per ton. The coal is delivered to a plant near the Powder River Basin from a specified mine. IPP has determined the contract does not meet the definition of a derivative because there is no method of net settlement. A price inflation clause in the agreement provides that the price per ton will be increased on each anniversary date by the change in a published market index for coal of the same quality as the coal in the Powder River Basin.

Is there an embedded derivative that needs to be bifurcated?

Analysis

The executory contract for the purchase of coal is the host contract. The price inflator would be a derivative on a stand-alone basis because there is a notional amount (100 tons of coal per week for 5 years), an underlying (the price of Powder River Basin coal), no initial net investment in the contract, and a cash settlement representing the price inflator. The economic characteristics of the published market index bear a close economic relationship to the host contract (the purchase of coal from a source in the

Powder River Basin). The pricing in the contract that includes the adjustment based on the change in the published market index would be expected to be closely correlated with the pricing at Powder River Basin. As such, the embedded derivative would not require separation from the host contract. If the inflator was based on a broader coal index that did not reflect the economic conditions of the region (e.g., the coal index was based on all of North and South America, but the region where the coal is sourced from is Powder River Basin), IPP would need to perform a detailed analysis to demonstrate that the economic characteristics and risks of the inflator were clearly and closely related to those of the host contract.

3.5 *Hedge accounting*

Commodity contracts that meet the definition of a derivative and do not qualify for or are not otherwise designated under a scope exception are accounted for at fair value. If a reporting entity executes contracts to manage risk associated with forecasted purchases or sales of power, natural gas, or other commodities, it may seek to apply hedge accounting to such derivatives to minimize volatility associated with recording changes in fair value in the income statement. Commodity derivatives may be designated in a cash flow or fair value hedge if all of the criteria in ASC 815 for hedge accounting are met. If cash flow hedging is used, changes in the fair value of the derivative associated with the effective portion of the hedge are initially recorded in other comprehensive income (OCI) and remain deferred in accumulated other comprehensive income (AOCI) until the underlying forecasted transaction impacts earnings or the forecasted transaction is deemed probable of not occurring.

The documentation and accounting requirements for hedge accounting are intricate and can be onerous. In addition, changes in commodity markets and the evolution of potential hedging strategies have perpetuated challenges in qualifying for hedge accounting at inception and on an ongoing basis. As a result, and to avoid potential misapplication of the hedge accounting guidance, some reporting entities may choose to instead enter into “economic” hedges. An economic hedge may be used for the same risk management purpose as an accounting hedge; however, because the contract is not designated as a hedge for accounting purposes, changes in fair value of the derivative are recorded in the income statement instead of being deferred in other comprehensive income.

ASC 815-20-25-1 outlines the main criteria necessary to qualify for hedge accounting. Figure 3-11 highlights key considerations related to applying the hedge accounting criteria to commodity cash flow hedges.

Figure 3-11
Key considerations for commodity cash flow hedge accounting

Requirement	Key industry considerations
Formal designation and documentation at hedge inception (UP 3.5.1)	<ul style="list-style-type: none"> □ Hedge should be concurrently designated and completely documented □ Detailed information about the hedge relationship and effectiveness methods to be used should be included in the documentation (ASC 815-20-25-3)
Eligibility of hedged items and transactions (UP 3.5.2)	<ul style="list-style-type: none"> □ The forecasted transaction is probable of occurring; consider counterparty credit worthiness □ Individual or groups of forecasted transactions may be designated in a hedge; in a hedge of a group of forecasted transactions, the transactions within the group should share similar risks □ The forecasted transaction should be documented with sufficient specificity so that it is clear what is being hedged, and to allow for appropriate de-designation when applicable □ A normal purchases and normal sales contract that is not a firm commitment can qualify as a hedged item □ A component risk of a commodity purchase cannot be the designated hedged item other than foreign currency risk; all changes in cash flows (including transportation as applicable) should be designated (ASC 815-20-25-15(i))
Eligibility of hedging instruments (UP 3.5.3)	<ul style="list-style-type: none"> □ A proportion of a hedging derivative can be used to hedge a forecasted transaction but portions representing different risks cannot be separately designated □ More than one derivative can be used in combination to hedge a forecasted transaction (e.g., two derivatives to hedge a price and locational basis difference)
Hedge effectiveness (UP 3.5.4)	<ul style="list-style-type: none"> □ Hedge effectiveness should be assessed at the time the hedge is designated and the hedging derivative should be expected to be highly effective in offsetting changes in cash flows relating to the hedged risk □ All potential sources of ineffectiveness (e.g., daily versus monthly pricing or settlements) should be identified and considered regardless of the method of assessing effectiveness that is used; ineffectiveness when using the critical terms match method should be expected to have a de minimis impact □ Counterparty credit worthiness should be considered as part of the evaluation of effectiveness

This section addresses specific issues encountered by utilities and power companies related to cash flow hedging for commodities. See DH 6 for further information on the requirements of and accounting for cash flow hedging in general, including cash flow hedges of other risks (e.g., interest rate risk on debt). See DH 5 for information about fair value hedging.

3.5.1 **Formal designation and documentation**

Certain criteria must be met for a derivative instrument and a hedged item to qualify for cash flow hedge accounting. In particular, the hedge relationship must be formally designated and documented at hedge inception.

Excerpt from ASC 815-20-25-3

Concurrent designation and documentation of a hedge is critical; without it, an entity could retroactively identify a hedged item, a hedged transaction, or a method of measuring effectiveness to achieve a desired accounting result.

The documentation requirements outlined in ASC 815-20-25-3 are voluminous, but a mandatory component of qualifying for hedge accounting. The designation and related documentation provide the foundation on which a reporting entity can qualify, monitor, and maintain an accounting hedging relationship. Furthermore, in addition to the documentation required at hedge inception, the assessment of hedge effectiveness and measurement of hedge ineffectiveness should be updated and documented each reporting period, and at least quarterly. A summary of the documentation requirements relating to cash flow hedges is included in Figure 3-12.

Figure 3-12 Cash flow hedge documentation requirements

ASC 815-20-25-3 includes the following hedge documentation requirements, which would be applicable for cash flow hedges of forecasted commodity transactions:

- The hedging relationship (e.g., a description of the hedge being undertaken)
- The risk management objective and strategy for undertaking the hedge, including: (1) the hedging instrument; (2) the hedged item or transaction; (3) the risk being hedged; (4) how effectiveness will be evaluated retrospectively and prospectively; and (5) how hedge ineffectiveness will be measured, if applicable
- Demonstration of the expectation that the hedging instrument will be highly effective in offsetting cash flows of the forecasted transaction
- The date on or period within which the forecasted transaction is expected to occur (e.g., a specific date or month) as well as the quantity being hedged (e.g., amount of megawatt-hours or MMBtus)

In addition, the forecasted transaction being hedged should be identified and documented in a manner that is specific enough to know what is being hedged.

Detailed documentation designed to meet the ASC 815-20-25-3 criteria is critical to comply with the hedge accounting requirements. See DH 6 for further information on cash flow hedging documentation requirements and DH 6.9 for sample hedge documentation.

3.5.2 Eligibility of hedged items and transactions

ASC 815-20-25-13 and 25-15 include specific guidance on the items or transactions eligible to be designated in a cash flow hedge.

Excerpt from ASC 815-20-25-13

An entity may designate a derivative instrument as hedging the exposure to variability in expected future cash flows that is attributable to a particular risk. That exposure may be associated with either of the following:

- a. An existing recognized asset or liability (such as all or certain future interest payments on variable-rate debt)
- b. A forecasted transaction (such as a forecasted purchase or sale).

Typically, the hedged item in a commodity cash flow hedge is a forecasted purchase or sale of a commodity, such as natural gas, coal, power, or fuel oil.

Definition from ASC 815-20-20

Forecasted Transaction: A transaction that is expected to occur for which there is no firm commitment. Because no transaction or event has yet occurred and the transaction or event when it occurs will be at the prevailing market price, a forecasted transaction does not give an entity any present rights to future benefits or a present obligation for future sacrifices.

ASC 815 permits a forecasted transaction to be the hedged item in a cash flow hedge if certain specified requirements are met. In addition to the basic criteria for hedge accounting, ASC 815-20-25-15 outlines the criteria for a forecasted transaction to qualify as the hedged transaction in a cash flow hedge. The key requirements in ASC 815-20-25-15 for a forecasted transaction to qualify for a commodity cash flow hedge include:

- The transaction is specifically identified as either a single transaction or group of transactions.
- The transaction is probable of occurring.
- The transaction represents an exposure to variable cash flows that impacts earnings and is with a third party.
- The transaction is not the acquisition of an asset or incurrence of a liability that will subsequently be measured at fair value, such as a derivative (i.e., a reporting entity cannot hedge a derivative with a derivative).

- If the hedged item is a nonfinancial transaction (e.g., a purchase or sale with physical delivery), the risk being hedged should be for all of the cash flows relating to the forecasted purchase or sale (i.e., the variability in all cash flows, including transportation to the item's location should be hedged; a reporting entity cannot hedge only a component risk of the forecasted transaction).

Each of these requirements is further discussed in this section.

Question 3-33

Can a contract designated under the normal purchases and normal sales scope exception qualify as the hedged item (forecasted transaction) in a cash flow hedge?

PwC response

It depends. A derivative cannot be a hedged item, but once the normal purchases and normal sales scope exception is elected, the contract is no longer within the scope of ASC 815. ASC 815-20-25-7 through 25-9 provide guidance on the designation of a normal purchase or normal sale contract as a hedged item. The contract can be designated as the hedged item in a fair value hedge if it meets the definition of a firm commitment, otherwise it could be the hedged transaction in a cash flow hedge. Whether the contract is a firm commitment will depend on whether the contract contains a fixed price and a disincentive for nonperformance that is sufficiently large such that performance under the contract is probable (definition of firm commitment from ASC 815-20-20). However, if the contract pricing is based on an index or other variable pricing, the reporting entity continues to have an earnings exposure and would be able to designate the contract as a forecasted transaction in a cash flow hedge, provided all the other criteria for cash flow hedging are met.

3.5.2.1 Transaction is specifically identified

When hedging a forecasted transaction, reporting entities have flexibility to hedge individual transactions or groups of individual transactions that share similar risks.

ASC 815-20-25-15(a)

The forecasted transaction is specifically identified as either of the following:

1. A single transaction
2. A group of individual transactions that share the same risk exposure for which they are designated as being hedged. A forecasted purchase and a forecasted sale shall not both be included in the same group of individual transactions that constitute the hedged transaction.

In either case, the cash flow hedge documentation should identify the forecasted transaction with sufficient specificity. The documentation requirement is further detailed in ASC 815-20-25-3(d)(1)(vi).

ASC 815-20-25-3(d)(1)(vi)

The hedged forecasted transaction shall be described with sufficient specificity so that when a transaction occurs, it is clear whether that transaction is or is not the hedged transaction. Thus, a forecasted transaction could be identified as the sale of either the first 15,000 units of a specific product sold during a specified 3-month period or the first 5,000 units of a specific product sold in each of 3 specific months, but it could not be identified as the sale of the last 15,000 units of that product sold during a 3-month period (because the last 15,000 units cannot be identified when they occur, but only when the period has ended).

When preparing hedge documentation, a reporting entity should ensure that there is sufficient specificity so that it is clear what forecasted transaction is being hedged. The designation and documentation of the hedged transaction depends on the nature of the forecasted transaction and, absent an all-in-one hedge of a firm commitment (see UP 3.5.2.5), linkage back to a specific vendor, customer, or contract is not required. For example, if a reporting entity is selling power into the open market, it should document details about the quantity, location, and timing of the forecasted sales, but it would not typically designate a specific contract or counterparty as part of the forecasted transaction.

Reporting entities should carefully consider how they describe the forecasted transaction in their documentation because it may impact the accounting upon discontinuation of the hedge. For example, if the documentation of a hedged transaction identifies forecasted sales to a specific counterparty, a subsequent conclusion that sales to that counterparty are probable of not occurring would lead to discontinuation of the hedge relationship and immediate release of amounts deferred in accumulated other comprehensive income. In contrast, if the designation is more general, changes in the customer mix alone would not affect the hedging designation.

Question 3-34

If a reporting entity is uncertain about the timing of a forecasted transaction, can it use a range of time in designating its forecasted transaction?

PwC response

No. As described in ASC 815-20-25-3, the forecasted transaction needs to be sufficiently specific so that it is clear what is being hedged. If only a general timeframe for occurrence of the forecasted transaction is documented, it may not be clear when the hedged transaction occurs. If a reporting entity is hedging a future sale of natural gas, it could specify the time period and quantity in a manner such as:

- The first 1,000 MMBtus of natural gas sold in each of the months of October, November, and December 2016
- The first 1,000 MMBtus of natural gas to be sold on December 15, 2016

By designating the hedged transaction as the first number of units sold during the specified period, a reporting entity is not “locked in” to a specific date, and if the transaction does not occur on that specific date, the reporting entity’s hedge will not be affected (as long as it occurs within a reasonable range; see UP 3.5.2.2 *Timing of the forecasted transaction* for further information about uncertainty within a range).

It would be insufficient to identify the hedged item in this scenario as “1,000 MMBtus of natural gas to be sold in the fourth quarter of 2016” or “the last 1,000 MMBtus of natural gas to be sold to Company X in December 2016.” By designating the hedge in either of these two ways, a reporting entity would be able to select which transactions in the fourth quarter or in December 2016 it uses as the forecasted transaction after the fact, which is inconsistent with the requirements in ASC 815-20-25-3(d)(1)(vi).

Hedging a group of forecasted transactions

Provided that the forecasted transactions are identified with sufficient specificity, a reporting entity could also hedge a group of forecasted transactions.

Excerpt from ASC 815-20-55-22

Under the guidance in this Subtopic, a single derivative instrument of appropriate size could be designated as hedging a given amount of aggregated forecasted transactions, such as any of the following:

- a. Forecasted sales of a particular product to numerous customers within a specified time period, such as a month, a quarter, or a year
- b. Forecasted purchases of a particular product from the same or different vendors at different dates within a specified time period

Although a group of forecasted transactions can be the hedged item in a cash flow hedge, ASC 815-20-25-15(a)(2) and ASC 815-20-55-23 require that the individual transactions within the group share the same risk exposure for which they are being hedged. For example, a group of natural gas sales at the same delivery location would be considered to share a similar risk. However, if the group of natural gas sales is at different locations, the variability of cash flows relating to those locations would need to be sufficiently correlated to support that the sales share the same risk exposure. In addition, ASC 815 precludes the grouping of a forecasted purchase and a forecasted sale (e.g., the risk of the spread between the two prices) because the risk exposures are different. ASC 815-20-55-14 provides guidance for evaluating a portfolio of assets or liabilities and whether it can be designated in a fair value hedging relationship.

Excerpt from ASC 815-20-55-14

If the change in fair value of a hedged portfolio attributable to the hedged risk was 10 percent during a reporting period, the change in the fair values attributable to the hedged risk for each item constituting the portfolio should be expected to be within a fairly narrow range, such as 9 percent to 11 percent. In contrast, an expectation that the change in fair value attributable to the hedged risk for individual items in the portfolio would range from 7 percent to 13 percent would be inconsistent with the requirement in that paragraph.

This test (known as the “similar assets test”) is specific to fair value hedges. ASC 815-20-25-15 does not specifically require reporting entities to perform this test for cash flow hedges of groups of individual transactions. However, we believe that the similar assets test guidance for fair value hedges is similarly applicable for evaluating cash flow hedges of groups of forecasted transactions. See DH 5.3.1 for further information on applying the similar assets test.

The similar assets test should be used by a reporting entity that designates a group of either forecasted sales or purchases at similar locations as a single hedged item. The similar assets test should be performed at inception of the hedging relationship as well as on an ongoing basis. Subsequent to the inception of the hedge, a reporting entity should monitor whether the group of transactions continues to meet the similar assets test (e.g., pricing relating to multiple locations within the group remains highly correlated). Any reasonable statistical method, such as regression analysis, can be used to support that the forecasted transactions are similar and have a similar set of risk exposures.

Simplified Example 3-26 illustrates the evaluation of a group of individual transactions being designated as a single hedged item. The example addresses only the similar assets test; the reporting entity would also need to meet all other hedge accounting requirements to designate a cash flow hedge.

EXAMPLE 3-26**Hedging accounting – group of forecasted sales of natural gas**

Guava Gas Company (GGC) sells natural gas at five locations in Texas. To mitigate cash flow volatility associated with fluctuating natural gas prices, GGC decides to hedge its forecasted sales. However, because it manages all of its sales in Texas as one portfolio, instead of designating a hedging relationship for each separate location, GGC designates all of its forecasted sales within one hedging relationship. The group of forecasted sales is hedged with NYMEX “pay fixed, receive floating” swaps based on the monthly Henry Hub index price. For purposes of this example, assume all physical sales are also based on a monthly index price.

What evidence and documentation must GGC have in place to support its designated hedging transaction?

Analysis

To hedge the forecasted sales at all five locations as a group (rather than individual transactions or locations), GGC would need to perform a quantitative similar assets test at inception to demonstrate that the sales at all five of the locations have similar risks. In general, the similar assets test may be difficult for locations that are geographically disbursed or where locational prices are impacted by congestion or other factors that would not impact all locations equally. For example, it may be difficult to group physical transactions at the SoCal Border (a market hub for natural gas located in California) and Houston Ship Channel (a market hub for natural gas located in Houston, Texas).

Another challenge in grouping transactions for hedge accounting is in establishing the perfect hypothetical derivative for purposes of effectiveness and ineffectiveness testing. The reporting entity will need to make an initial assessment of the mix of transactions (e.g., 50% Houston Ship Channel, 50% Henry Hub) and would use that hypothetical derivative in its testing. The perfect hypothetical derivative would need to be updated if the forecast changes, which may lead to additional ineffectiveness in a particular period. In addition, a reporting entity's inability to accurately forecast the mix of sales may lead to a conclusion that a group method should not be applied.

Each time effectiveness is assessed, GGC would need to perform either a qualitative or quantitative analysis to demonstrate that the five locations continue to share similar risks. The determination of whether a quantitative or qualitative analysis is sufficient is highly judgmental and will depend on the nature of the commodity being hedged and the volatility of the prices within the group of forecasted transactions. If at any point in the hedging relationship, any one or more of the five locations fails the similar assets test, the entire hedging relationship should be de-designated. GGC may be able to enter into a new hedging relationship with the remaining locations that would qualify for the similar assets test.

Finally, this example focuses on grouping physical locations. In general, we would not expect a group including more than one commodity or different pricing structures (e.g., monthly, daily) to qualify for designation as the hedged item, because the forecasted transactions would not qualify under the similar asset test.

3.5.2.2 *Forecasted transaction is probable of occurring*

A key tenet to qualify to hedge a forecasted transaction is that the transaction is probable of occurring.

Excerpt from ASC 815-20-55-24

An assessment of the likelihood that a forecasted transaction will take place (see paragraph 815-20-25-15[b]) should not be based solely on management's intent because intent is not verifiable. The transaction's probability should be supported by observable facts and the attendant circumstances. Consideration should be given to all of the following circumstances in assessing the likelihood that a transaction will occur.

- a. The frequency of similar past transactions
- b. The financial and operational ability of the entity to carry out the transaction
- c. Substantial commitments of resources to a particular activity . . .
- d. The extent of loss or disruption of operations that could result if the transaction does not occur
- e. The likelihood that transactions with substantially different characteristics might be used to achieve the same business purpose

The evaluation of whether the forecasted transaction is probable of occurring is highly judgmental; “probable” in the context of hedge accounting is used in the same manner as in ASC 450. Specifically, the term probable means that “the future event or events are likely to occur” and thus the likelihood of occurrence is significantly greater than what is indicated by the phrase more likely than not. Although ASC 815 and ASC 450 do not establish bright lines, we believe that a transaction may be considered probable of occurring when there is at least a 75%-80% chance that it will occur on the specified date. In addition, there should be compelling evidence to support management’s assertion that the forecasted transaction is probable.

In addition to the impact on qualifying for hedge accounting, the assessment of whether the forecasted transaction is probable also impacts potential discontinuation of the hedge. The guidance on discontinuation of a cash flow hedge in ASC 815-30-40-1 through 40-5 explains how to address a change in the probability of a forecasted transaction subsequent to the initial designation of the hedging relationship. The impact of changes will depend on the reporting entity’s expectations regarding the possibility or probability of the originally forecasted transaction occurring at a certain time or not at all, as summarized in Figure 3-13 and further discussed below.

Figure 3-13
Impact on hedge accounting of a change in the probability of a forecasted transaction

Probability of forecasted transaction	Application of hedge accounting	Amounts deferred in accumulated OCI
Probable of occurring and hedge criteria continue to be met	Continue (unless the reporting entity elects to discontinue)	Reclassify out of AOCI into earnings only when the forecasted transaction impacts earnings
Reasonably possible of occurring (no longer probable)	Discontinue; record changes in fair value of the derivative in earnings going forward	Reclassify out of AOCI into earnings only when the forecasted transaction impacts earnings

Probability of forecasted transaction	Application of hedge accounting	Amounts deferred in accumulated OCI
Probable of not occurring	Discontinue; record changes in fair value of the derivative in earnings going forward	Immediately reclassify out of AOCI into earnings

As summarized in Figure 3-13, ASC 815-30-40-1 requires that if any of the cash flow hedge accounting criteria are no longer met, the hedging relationship should be discontinued; amounts previously deferred in accumulated other comprehensive income should continue to be deferred and recognized as the forecasted transaction impacts earnings or recognized in full immediately when the transaction is probable of not occurring. Changes in the fair value of the derivative instrument are recorded in earnings going forward, unless the instrument is designated as a hedging instrument in a new hedging relationship.

Documentation

We understand that the SEC staff believes management should formally document the circumstances that were considered in concluding that a transaction is probable. If a reporting entity has a pattern of determining that forecasted transactions are no longer probable of occurring, the appropriateness of management's previous assertions and its ability to make future assertions regarding forecasted transactions may be called into question. The SEC staff takes the position that although one instance of a changed assertion does not constitute a pattern, recurrence will quickly raise a red flag. The consequences (e.g., possible restatement) are serious; therefore, reporting entities need to be able to support their assertion that forecasted transactions are probable of occurring if cash flow hedge accounting is being sought.

In assessing the probability of the forecasted transaction occurring, a reporting entity should consider its past history in executing similar types of hedging transactions and its success in accurately forecasting these transactions. For example, a regulated utility may have a long history of buying a certain amount of power to support retail load during the third quarter of the year. It may be relatively easy to support a forecasted transaction that represents only a portion of the historical purchases and current forecast (and would become increasingly difficult as the percentage hedged increases). In contrast, if a power company has a new peaking facility and intends to sell into a new market, it may be more difficult to support a probable level of sales, compared to selling into a region where it has a longstanding history of successfully forecasting its sales.

The FASB specifically addresses the length of time that is expected to pass before a forecasted transaction is projected to occur and the quantity involved in the forecasted transaction as key considerations in assessing probability.

ASC 815-20-55-25

Both the length of time until a forecasted transaction is projected to occur and the quantity of the forecasted transaction are considerations in determining probability. Other factors being equal, the more distant a forecasted transaction is or the greater the physical quantity or future value of a forecasted transaction, the less likely it is that the transaction would be considered probable and the stronger the evidence that would be required to support an assertion that it is probable.

Therefore, a reporting entity should consider whether the volume of planned sales or purchases for the particular commodity, location, and timing for the forecasted transaction support a probable assertion. In making the probable assessment, the reporting entity should consider the volume of forecasted transactions (sales) and/or needs (purchases) compared to the designated hedge volume. For example, a power generation facility that is hedging its exposure to sales of power would need to forecast its wholesale load requirements and other non-derivative power sales to determine the total forecasted sales eligible for hedge accounting. This forecast should not include any derivative power sales contracts or any fixed-priced sales transactions, because neither a derivative nor a fixed-price firm commitment can be designated as the hedged item in a cash flow hedge.

Absent a contractual commitment for volumes, it may be challenging for a reporting entity to assert that a forecasted sale constituting a high percentage of its sales is probable, due to potential volatility of market demand. Similarly, if a power company produces energy using natural gas and wants to hedge its supply, it may be difficult to support designating a high percentage of its forecasted purchases of natural gas if energy sales are highly dependent on volatile markets.

Counterparty creditworthiness

Reporting entities should also consider the guidance in ASC 815-20-25-16(a) when assessing the probability of the forecasted transaction.

ASC 815-20-25-16(a)

Effect of counterparty creditworthiness on probability. An entity using a cash flow hedge shall assess the creditworthiness of the counterparty to the hedged forecasted transaction in determining whether the forecasted transaction is probable, particularly if the hedged transaction involves payments pursuant to a contractual obligation of the counterparty.

This assessment should be performed at least quarterly at the time of hedge effectiveness testing. If the probability of the forecasted transaction changes as a result of a change in counterparty creditworthiness, the reporting entity would need to evaluate whether its hedge continues to qualify. See Figure 3-14 for further information.

Timing of the forecasted transaction

When designating a forecasted transaction in a cash flow hedge, there may be a specific date on which the transaction is expected to occur (e.g., there is a contractual commitment for delivery on December 15, 20X2). However, in many cases delivery will be expected during a defined period rather than on a specific date. For example, deliveries of energy may be expected to occur during the third quarter but there may be uncertainty regarding the delivery month. ASC 815-20-25-16 provides guidance on the timing and probability of a forecasted transaction and specifically regarding uncertainty within a range.

Excerpt from ASC 815-20-25-16(c)

Uncertainty of timing within a range. For forecasted transactions whose timing involves some uncertainty within a range, that range could be documented as the originally specified time period if the hedged forecasted transaction is described with sufficient specificity so that when a transaction occurs, it is clear whether that transaction is or is not the hedged transaction. As long as it remains probable that a forecasted transaction will occur by the end of the originally specified time period, cash flow hedge accounting for that hedging relationship would continue.

Therefore, although uncertainty within a time period does not preclude hedge accounting (as long as the forecasted transaction is identified with sufficient specificity), the reporting entity should continue to monitor whether there are changes in the timing of the forecasted transaction.

If there is a change in the timing of the forecasted transaction such that it is no longer probable of occurring as originally documented, in general, the hedge should be discontinued. However, ASC 815-30-40-4 provides guidance in cases where it is still reasonably possible that the transaction will occur within two months of the original timing.

Excerpt from ASC 815-30-40-4

The net derivative instrument gain or loss related to a discontinued cash flow hedge shall continue to be reported in accumulated other comprehensive income unless it is probable that the forecasted transaction will not occur by the end of the originally specified time period (as documented at the inception of the hedging relationship) or within an additional two-month period of time thereafter.

If it is determined that the forecasted transaction has become *probable of not occurring* within the documented time period plus a subsequent two-month period, then the hedging relationship should be discontinued and amounts previously deferred in accumulated other comprehensive income should be immediately reclassified to earnings. See DH 9.1.2 for further information on discontinuation of cash flow hedges.

Changes in markets or pricing locations

In addition to changes in timing of the forecasted transaction, there may be other events or changes in the transaction that cause it to be no longer probable of occurring. The possibility of such changes should be considered in evaluating the probability of the forecasted transaction.

In particular, power markets continue to change and evolve. For example, some markets in recent years have increased the specificity of pricing by moving from nodal pricing to locational marginal pricing. In addition, a hedging derivative or normal purchases and normal sales contract designated as the hedged item could specify the substitution of a pricing point (location) or index to be used in the event the pricing index specified in the contract is no longer available.

A new market structure or the requirement to use a different index may result in or be an indication of a lack of liquidity at the existing location, which may call into question whether the forecasted transaction is still probable of occurring. For example, a change from a nodal market to locational margin pricing may result in a decline in liquidity for pricing locations that were previously used by market participants. The elimination or reduced liquidity of trading points may result in such points no longer having a risk profile that correlates with the original hedged transaction. As a result, reporting entities would need to consider whether existing hedges are still effective or whether they should be de-designated and re-designated.

When there is a market structure change or other pricing changes, reporting entities will also need to consider the impact on prospective effectiveness assessments for future transactions. There may be a lack of historical pricing information in the new market to support the effectiveness test prospectively. Reporting entities that have an accounting policy to use historical pricing information in their effectiveness assessments will need to consider what other information may be available to support the prospective tests, such as forward pricing information. Due to the lack of historical information, judgment and rigor will be needed in performing effectiveness tests using forward pricing information. Any new market structure with significant changes will also need to be incorporated into future hedge designations. See UP 3.5.4 for further information on evaluating hedge effectiveness.

Application examples — changes in the forecasted transaction

Simplified Examples 3-27 through 3-30 illustrate the impact of various types of changes in the forecasted transaction. In addition, ASC 815-30-55-100 through 55-105 provide case studies to illustrate this guidance.

EXAMPLE 3-27**Hedge accounting — natural gas sales shortfall compared to forecast**

In October 2012, Guava Gas Company (GGC) enters into a cash flow hedge of the sale of the first 10,000 MMBtus of natural gas per month in each of January through March 2013. The probability of the forecasted transaction was supported by GGC's current forecast, for which it had performed backtesting of its accuracy. GGC has also

met all of the other requirements for cash flow hedge accounting. In January 2013, GGC sells only 8,000 MMBtus of natural gas.

How should GGC account for its shortfall in sales in January?

Analysis

The amounts deferred in accumulated other comprehensive income related to the 8,000 MMBtus of January sales would be released to net income because the forecasted transaction occurred. GGC has already designated and hedged the first 10,000 MMBtus of sales of natural gas in February 2013. Therefore, the shortfall of 2,000 MMBtus in January 2013 cannot carry over as the “first” sales in February 2013. However, if GGC can support that it will sell additional natural gas in February 2013 (e.g., the sale of the volumes from 10,001 MMBtus through 12,000 MMBtus), then the amount previously deferred in accumulated other comprehensive income related to 2,000 MMBtus of shortfall in January 2013 should continue to be deferred because the forecasted transaction will occur within two months of the originally designated time period. The deferred amounts in AOCI would then be released to net income in February as the deliveries in excess of the first 10,000 MMBtus occur. GGC will also need to reevaluate whether the hedge is still effective, which may not be the case because of the change in time period for a portion of the forecasted sales.

If it is remote that GGC will have sales in excess of 10,000 MMBtus in February or March (two months beyond the initial designated period) then the forecasted transaction has become probable of not occurring. In that case, the hedging relationship should be discontinued and the amounts deferred in AOCI should be immediately released into earnings.

EXAMPLE 3-28

Hedge accounting — change in forecasted natural gas sales

In October 2014, Ivy Power Producers (IPP) enters into a natural gas swap contract to fix the price of 50,000 MMBtus of natural gas purchases per month for the period from January through March 2015. Based on IPP’s forecast, it expects to buy 100,000 MMBtus per month during this period. IPP designates and documents the swap as a cash flow hedge of its forecasted purchase of the first 50,000 MMBtus of natural gas purchased each month during the period. The natural gas purchased will be used to generate power at the Maple Generating Station. Assume all of the criteria for hedge accounting have been met.

In February 2015, due to a drop in power prices, IPP decides to purchase, rather than generate power for sales to its customers. As a result, IPP purchases only 20,000 MMBtus of natural gas in February 2015. In addition, IPP believes it is remote that it will purchase more than 10,000 MMBtus of natural gas in March through June 2015, therefore determining that it is probable its forecasted transaction will not occur.

How should IPP account for the changes in its forecast?

Analysis

Because IPP has determined that it is probable that the forecasted transaction will not occur, it should de-designate the hedging relationship and record subsequent changes in the fair value of the swap through earnings. In addition, the amounts previously deferred in accumulated other comprehensive income should be immediately released into earnings because the forecasted transaction is now probable of not occurring.

EXAMPLE 3-29**Hedge accounting — change in forecasted power sales**

In October 2014, Ivy Power Producers (IPP) enters into a receive fixed (\$90/MWh), pay floating swap for the hourly amount of 200 MWs of energy during on-peak hours for the period January 1, 2015 through March 31, 2015. The contract is designated as a hedge of forecasted power sales from the Maple Generating Station. The swap notional is based on IPP's forecast of power sales. In January 2015, IPP's plant is shut down due to a forced outage and no power is produced. IPP does not expect the plant to be back online until May 2015; therefore, it determines that it is probable the forecasted transaction will not occur.

How should IPP account for the changes in its forecast?

Analysis

Because IPP has determined it is probable that the forecasted transaction will not occur, it should terminate the hedging relationship immediately and record subsequent changes in the fair value of the swap through earnings. In addition, the amounts deferred in accumulated other comprehensive income should be immediately released into earnings. Because IPP does not expect to be able to sell until at least May 2015, the sales are probable of not occurring within two months of the original time period of January through March 2015.

EXAMPLE 3-30**Hedge accounting — forecasted transaction is no longer probable**

As of December 31, 2014, Ivy Power Producers (IPP) has hedged its forecasted purchases of natural gas of 200,000 MMBtus for the month of March 2015 using a combination of different hedging instruments. The derivatives are designated using a first-in, first-out methodology (i.e., the first derivative entered into for the specified period hedges the first sales in the month, the next derivative hedges the next sales in the month, and so forth). IPP designates the sequencing of the hedges at the time of contract execution to have an effective hedging relationship.

On December 31, 2014, IPP determines that 50,000 MMBtus of forecasted purchases in March 2015 and within two months are probable of not occurring.

How should IPP account for the hedged transactions in the sequence that are not probable of occurring?

Analysis

IPP should discontinue hedge accounting on a portion of the derivatives for which the forecasted transaction will not occur, and a corresponding portion of the amount deferred in accumulated other comprehensive income should be immediately reclassified into current earnings. In determining the amounts to be reclassified out of AOCI, the same sequencing used in the hedge designation (last-in, first-out) should be applied. That is, the last contract entered into and designated as a hedge of March 2015 purchases of natural gas would be the first contract de-designated.

3.5.2.3 *Earnings exposure*

Another key characteristic for a forecasted transaction to qualify for hedge accounting is that it should represent an earnings exposure for the reporting entity. Therefore, in accordance with ASC 815-20-25-15(c), a forecasted transaction must be with a party external to the reporting entity (although intercompany hedges for foreign currency exposures are permitted). In addition, the forecasted transaction should present a risk of changing cash flows that could impact reporting earnings (for the hedged risk).

Because a forecasted transaction must be with a party external to the reporting entity to qualify as an earnings exposure, the effects of any intercompany hedges between a parent and its subsidiaries or among subsidiaries should be reversed in the consolidated financial statements (other than hedges of foreign exchange risk). However, as long as the parent and subsidiary have the same functional currency, a subsidiary can apply hedge accounting to a hedge of a forecasted intercompany transaction in its stand-alone financial statements. At the subsidiary reporting level, that transaction is with an external party.

In addition, although a reporting entity cannot apply hedge accounting for non-foreign-currency-denominated intercompany forecasted transactions at the consolidated level, it is acceptable to hedge different exposures at different reporting levels. For example, a parent company may enter into a natural gas swap and designate that swap as a cash flow hedge of forecasted sales of natural gas by one of its subsidiaries. In this scenario, the parent company may apply hedge accounting in the consolidated financial statements if the swap was designated to hedge a risk exposure at the consolidated reporting level, the forecasted transaction is with an external party, and all other hedge accounting criteria are met. The subsidiary, however, will not apply hedge accounting in its stand-alone financial statements because the derivative instrument is not held at that level.

3.5.2.4 *Risks eligible for hedging*

A key consideration when establishing an accounting hedge is the appropriate designation of the risk to be hedged and appropriate matching of the risk with the hedging instrument. In accordance with ASC 815-20-25-15(i), the hedged risk in a

forecasted sale or purchase of a nonfinancial item (such as a commodity) should be the risk of changes in total cash flows related to all price changes of the commodity.¹²

Excerpt from ASC 815-20-25-15(i)

If the hedged transaction is the forecasted purchase or sale of a nonfinancial asset, the designated risk being hedged is either of the following:

...

2. The risk of changes in the cash flows relating to all changes in the purchase price or sales price of the asset reflecting its actual location if a physical asset..., not the risk of changes in the cash flows relating to the purchase or sale of a similar asset in a different location or of a major ingredient.

Therefore, a reporting entity cannot designate the price of natural gas as the hedged risk in a forecasted purchase of power, because the cash flow risk from the change in the price of natural gas is only a portion of the overall risk of the changes in cash flows relating to power.

However, a reporting entity could potentially use a natural gas derivative as a cash flow hedge of the entire forecasted purchase or sale of power. The reporting entity would need to designate all of the cash flows relating to the forecasted purchase of power as the hedged risk, and the change in fair value of the natural gas derivative should be expected to be highly effective at offsetting the total changes in those cash flows. All other hedge criteria should also be met. This hedging relationship may be highly effective in circumstances where power prices are highly correlated to natural gas. However, some ineffectiveness would be expected because changes in power prices are not entirely due to the change in natural gas prices.

3.5.2.5 All-in-one hedges

A reporting entity may wish to manage the risk of changing cash flows due to price variability prior to the purchase or sale, by entering into a firm purchase commitment. Generally, non-foreign-currency-denominated firm commitments are not eligible for designation as a hedged item in a cash flow hedging transaction because there is no variability in cash flows due to the fixed price in the firm commitment. However, the FASB provided an exception in ASC 815-20-25-22¹³ to permit a firm commitment to be designated as the hedging instrument in a cash flow hedge of a forecasted transaction that will be consummated upon gross settlement of the firm commitment itself.

¹² Foreign exchange risk alone may be a designated risk in a hedge of a forecasted purchase or sale of a nonfinancial asset. For the purposes of this section, we discuss only price risk. See DH 7.7.2 for further information on designating foreign currency risk in a cash flow hedge.

¹³ Guidance originally issued as DIG Issue G2, *Cash Flow Hedges: Hedged Transactions That Arise From Gross Settlement of a Derivative ("All-in-One" Hedges)*.

Definition in ASC 815-20-20

All-in-One Hedge: In an all-in-one hedge, a derivative instrument that will involve gross settlement is designated as the hedging instrument in a cash flow hedge of the variability of the consideration to be paid or received in the forecasted transaction that will occur upon gross settlement of the derivative instrument itself.

For a contract to qualify for designation in an all-in-one hedge, it must meet the definition of both a firm commitment and a derivative instrument.

Application example—All-in-one hedges

Simplified Example 3-31 provides an illustration of an all-in-one hedge transaction.

EXAMPLE 3-31**Hedge accounting — all-in-one hedge of natural gas**

Ivy Power Producers (IPP) enters into a contract for the purchase of 10,000 MMBtus of natural gas per day in the month of July 2014 for \$3.00/MMBtu. The contract meets the definition of a derivative. IPP determines that the contract is not eligible for the normal purchases and normal sales scope exception because it may be subject to net settlement as a result of its default provisions. Management has determined that the contract is probable of being physically settled.

Can IPP designate the contract as an all-in-one hedge?

Analysis

IPP has a firm commitment for the daily purchase of 10,000 MMBtus at a fixed price. It could designate the contract as an all-in-one hedge of the future purchase of natural gas. In addition, because the hedged item (the forecasted purchase of 10,000 MMBtus per day in July 2014) and the hedging instrument (the firm commitment) are the same transaction, the critical terms match and the forecasted transaction is settled with the delivery of the natural gas pursuant to the firm commitment. As such, there is an expectation of no ineffectiveness for this hedging transaction, and the critical terms match method can be used to assess effectiveness. See UP 3.5.4.3 for further information on the critical terms match method of assessing hedge effectiveness.

3.5.3 Eligible hedging instruments

ASC 815 allows entire derivatives or proportions thereof, as well as multiple derivatives together (or proportions of them) to be designated as a hedging instrument. A derivative cannot be separated into different time periods or different components because those would have different risk profiles. Separating a derivative in this manner would not necessarily result in the appropriate offset of cash flows relating to the risk being hedged.

Excerpt from ASC 815-20-25-45

Either all or a proportion of a derivative instrument (including a compound embedded derivative that is accounted for separately) may be designated as a hedging instrument. Two or more derivative instruments, or proportions thereof, may also be viewed in combination and jointly designated as the hedging instrument. A proportion of a derivative instrument or derivative instruments designated as the hedging instrument shall be expressed as a percentage of the entire derivative instrument(s) so that the profile of risk exposures in the hedging portion of the derivative instrument(s) is the same as that in the entire derivative instrument(s).

The following questions address specific issues related to application of this guidance.

Question 3-35

Can a proportion of a one-year natural gas swap be designated as a cash flow hedge of a forecasted transaction?

PwC response

Yes. In accordance with ASC 815-20-25-45, a reporting entity can designate a proportion of a derivative in a hedging relationship. A proportion should be expressed in the hedge documentation as a percentage of a derivative's notional amount over the entire term (e.g., 40% of 20,000 MMBtus over the entire term of the contract). It should be noted that the designation must be the proportion over the contract tenor, and different amounts should not be designated in different periods (see Question 3-36).

A reporting entity may also use proportions of a derivative in separate hedging relationships. For example, if 40% of the notional of a natural gas swap were used in one hedging relationship, all or a proportion of the remaining notional could be used in a separate hedging relationship. Each individual hedging relationship would have to be assessed separately to determine whether it meets the requirements for hedge accounting.

Question 3-36

Can a reporting entity select only certain months of a one-year derivative to hedge forecasted transactions of those specific months?

PwC response

No. ASC 815 precludes designating a portion of a hedging derivative that represents different risks as a hedging instrument. The risk profile of a calendar-year natural gas swap will change over the course of the year due to price fluctuations arising from seasonal changes in natural gas supply and demand. If a one-year swap is used to hedge forecasted purchases in only three months of the year, the derivative would not be expected to appropriately offset the cash flows. However, the reporting entity could designate a proportion of the notional of the swap (e.g., 50%) for each month of the

contract as a hedge of a forecasted transaction for each of the corresponding months. Alternatively, the reporting entity could enter into separate contracts for different time periods during the year and designate the separate contracts as hedges as applicable.

3.5.3.1 Contracts with fixed and variable pricing

Contracts with variable pricing and a fixed spread

ASC 815-20-55-46 and 55-47 indicate that a commodity contract that has index pricing with a fixed spread cannot be designated as a hedging instrument in the cash flow hedge of a forecasted transaction (e.g., a contract for the purchase of natural gas at NYMEX Henry Hub plus \$1.00). The guidance indicates that the underlying in these types of contracts is related only to changes in the basis differential (i.e., the fixed spread). As a result, using such an instrument to hedge a forecasted transaction where the variability in cash flows is based both on the basis spread and the index price would result in only a portion of the variability in cash flows being offset.

Excerpt from ASC 815-20-55-47

The entity is not permitted to designate a cash flow hedging relationship as hedging only the change in cash flows attributable to changes in the basis differential. For an entity to be able to conclude that such a hedging relationship is expected to be highly effective in achieving offsetting cash flows, the entity would need to consider the likelihood of changes in the base commodity price as remote or insignificant to the variability in hedged cash flows (for the total purchase or sales price). However, the mixed-attribute contract may be combined with another derivative instrument whose underlying is the base commodity price, with the combination of those derivative instruments designated as the hedging instrument in a cash flow hedge of the overall variability of cash flows for the anticipated purchase or sale of the commodity.

Therefore, reporting entities wishing to hedge a forecasted transaction using a derivative that is priced at index plus a fixed adder should carefully evaluate whether the hedge will be effective. In addition to determining if the hedge will be effective, reporting entities should also consider the impact on the calculation of effectiveness on an ongoing basis.

Basis swaps

Basis swaps are similar to contracts with variable pricing plus a fixed spread in that a basis swap represents the difference between two locations or underlyings and therefore is used to close off such differences (similar to a fixed spread, which is generally intended to compensate for location differences). Because a basis swap does not fix the price, it cannot be used as a hedging instrument on a stand-alone basis; however, a basis swap can be used in combination with a forward or futures contract as a combined hedging instrument to hedge a forecasted transaction. The following questions illustrate scenarios where basis swaps may be used.

Question 3-37

Can a natural gas futures contract and a basis swap be used in combination to hedge a forecasted transaction?

PwC response

Yes. Two derivatives (i.e., a futures contract and a basis swap) can be used together to hedge a forecasted sale or purchase. A reporting entity may use this strategy if the forecasted transaction will occur at a location for which there is no stand-alone index (e.g., hedging a forecasted transaction at Houston Ship Channel with a NYMEX future priced based on Henry Hub). The futures contract would be used to fix the price of natural gas and the basis swap would be used to bridge the two indices (i.e., from the NYMEX future to the actual location of the forecasted transaction, in this case Houston Ship Channel).

Application example — hedging with basis swaps

The following simplified example further illustrates the use of basis swaps.

EXAMPLE 3-32**Hedge accounting — use of a natural gas futures contract and basis swap in combination to hedge a forecasted transaction**

Guava Gas Company (GGC) has forecasted sales of 10,000 MMBtus of natural gas per day in the month of April 2015 at Houston Ship Channel. It decides to hedge the forecasted transaction. On January 1, 2015, GGC enters into a NYMEX futures contract priced based on Henry Hub for 10,000 MMBtus of natural gas per day for April 2015. Subsequently, on February 15, 2015, it enters into a receive Houston Ship Channel, pay Henry Hub basis swap for 10,000 MMBtus of natural gas per day in April 2015.

Can GGC designate the futures contract as a cash flow hedge on January 1, 2015?

Analysis

Assuming that all of the hedge criteria have been met, including the assessment that using the NYMEX future will result in a highly effective hedge, GGC can designate the futures contract as a cash flow hedge on January 1, 2015. This hedging relationship would result in ineffectiveness due to the Henry Hub-Houston Ship Channel basis difference.

When GGC enters into the basis swap on February 15, 2015, the original hedge would need to be de-designated and re-designated, if it wants the basis swap to be designated as a hedge for accounting purposes. The basis swap cannot be designated by itself as the hedging instrument (because it does not fix the cash flows) and also cannot be added to the existing hedging relationship. Furthermore, because the NYMEX futures contract has a fair value on February 15, 2015, GGC would need to consider the impact of the day one value on hedge effectiveness. In implementing this

strategy, GGC may alternatively elect to retain the original hedging relationship and allow the basis swap to be recorded directly to earnings (rather than designating it in a hedge). The changes in fair value of the basis swap would be expected to offset the ineffectiveness associated with the original hedging relationship.

3.5.3.2 *Changes in the hedging instrument*

Reporting entities should also consider the impact on an existing hedge when there are changes in the hedging instrument. In particular, if a hedging instrument is terminated, the hedge should be de-designated.

Excerpt from ASC 815-30-40-1

An entity shall discontinue prospectively the accounting specified in paragraphs 815-30-35-3 and 815-30-35-38 through 35-41 for an existing hedge if any one of the following occurs:

...

(b) The derivative instrument expires or is sold, terminated, or exercised.

In considering changes to derivatives designated as hedging instruments, one specific area of concern is when a derivative is modified and/or novated such that there is a new counterparty, as discussed in the following questions.

Question 3-38

What is the impact on hedge accounting when the terms of the hedging derivative are modified?

PwC response

Subsequent to the inception of a hedging relationship, a derivative counterparty may decide to novate the contract and engage a new counterparty. It may also modify the terms of the contract by altering the pricing. This raises a question as to whether the reporting entity would be able to continue the original hedging relationship when the swap is novated.

When a contract is novated, and the original terms of the contract are modified, it effectively results in a termination of the existing contract and the creation of a new contract. For the original hedging relationship to remain intact, the original terms of the hedging derivative should remain unchanged (other than for changes that are not substantive). A change such as pricing is considered substantive. Although hedge accounting is discontinued, a reporting entity may designate the novated swap as a hedging instrument in a new hedging relationship, provided it meets the conditions required for hedge accounting. The fair value on the date of novation would need to be considered in the evaluation of effectiveness and measurement of ineffectiveness of the new hedging relationship.

Question 3-39

What is the impact on hedge accounting when the hedging derivative is novated as a result of new legislation arising from the Dodd-Frank Wall Street Reform and Consumer Protection Act of 2010 (the Dodd-Frank Act)?

PwC response

As discussed in Question 3-38, contract modifications and novations generally result in the de-designation of an existing hedge. Under Title VII of the Dodd-Frank Act, certain derivatives that are executed in the over-the-counter market may be required to be cleared through derivative clearing organizations or clearing agencies, resulting in novations of the existing contracts.

The SEC staff has responded to questions about the accounting impact of these novations, particularly with respect to hedge accounting. The SEC staff has indicated that it would not object to a conclusion that, for accounting purposes, the original derivative contract is not considered terminated and replaced with a new derivative contract, nor would it object to the continuation of the existing hedging relationship, provided that other terms of the contract have not been changed. The SEC staff's views apply to the following circumstances that are potentially applicable to utilities and power companies:

- For an over-the-counter derivative transaction entered into prior to the application of mandatory clearing requirements, a reporting entity voluntarily clears the underlying over-the-counter derivative contract through a central counterparty, even though the counterparties had not agreed in advance that the contract would be novated to effect central clearing.
- For an over-the-counter derivative transaction entered into subsequent to the application of mandatory clearing requirements, the counterparties to the underlying contract agree in advance that the contract will be cleared through a central counterparty in accordance with standard market terms and conventions, and the hedging documentation describes the counterparties' expectations that the contract will be novated to the central counterparty.

Changes to the terms of the over-the-counter derivative contract that are a direct result of the novation of the contract to the central counterparty would not preclude the continuation of hedge accounting. For example, contractual collateral requirements of the original contract may change as a direct result of the novation, because the original counterparties must now comply with the contractual collateral requirements of the central counterparty. This guidance should not be interpreted as permitting any novation of a derivative contract to be viewed as a continuation of an existing derivative contract. The SEC staff's view is focused solely on the instances outlined above.

Question 3-40

Can a cash flow hedge relationship continue when an exchange offsets a hedging derivative against other positions?

PwC response

It depends. A reporting entity may have outstanding exchange-traded derivative transactions (e.g., futures contracts, swaps) that have been designated as hedging instruments in cash flow hedging relationships. An exchange may choose to offset these against other derivative transactions held by the reporting entity prior to the settlement of the transactions as a result of margin posting or other purposes.

ASC 815-30-40-1 provides specific guidance on when a hedging relationship should be discontinued. In making this assessment, the reporting entity should use judgment in evaluating whether the offsetting of contracts by an exchange results in the expiration, sale, or termination of the derivative instrument. The impact of offsetting by the exchange on an existing contract is a legal determination. Therefore, we believe reporting entities should consult with legal counsel to make this determination.

3.5.4 Hedge effectiveness

In accordance with ASC 815, a reporting entity should have an expectation that a hedging relationship will be highly effective in achieving offsetting cash flows attributable to the hedged risk during the term of the hedge. Key requirements include:

- A reporting entity is required to document how it will assess hedge effectiveness and the method selected should be applied consistently throughout the life of the hedge.
- There should be a reasonable basis for how the reporting entity plans to assess hedge effectiveness.
- The reporting entity should assess hedge effectiveness for all similar hedges in a similar manner, unless a different method can be justified.

The effectiveness assessment should be performed whenever financial statements are reported, and at least every three months. In addition to assessing *effectiveness*, reporting entities are required to measure *ineffectiveness* on a quarterly basis. The measurement of ineffectiveness is separate from the effectiveness assessment.

At a high level, there are three methods of evaluating effectiveness, as highlighted in Figure 3-14.

Figure 3-14
Methods of evaluating cash flow hedge effectiveness

Long-haul (Quantitative)	Critical terms match (Primarily qualitative)	Short cut (Qualitative)
<ul style="list-style-type: none"> □ Available for any qualifying hedging relationship □ At inception—quantitative prospective analysis □ Quarterly—retrospective and prospective testing □ Different methods may be used; commonly a hypothetical derivative is created and regression analysis is used 	<ul style="list-style-type: none"> □ Available for commodity hedges; allows the assumption of no ineffectiveness if certain criteria are met □ At inception—qualitative prospective analysis; quantitatively demonstrate and document that any potential sources of ineffectiveness are <i>de minimis</i> □ Quarterly—qualitative testing, including updates to original analysis if necessary 	<ul style="list-style-type: none"> □ Not available for commodity hedges; applies only to “plain-vanilla” interest rate swaps □ See DH 8.2 for information

Note that Figure 3-14 focuses on the applicability of effectiveness methods for commodity hedges. See DH 6 for further information on cash flow hedges in general and DH 8 for information on effectiveness evaluations in general, including for hedges of other risks such as interest rate risk. The following section addresses a few key considerations in evaluating hedge effectiveness for commodity hedge relationships.

3.5.4.1 Overall consideration — counterparty credit

In order for a hedging relationship to qualify for hedge accounting, there should be an expectation of high effectiveness throughout the hedge period. Nonperformance risk is an integral part of the determination of the fair value of a derivative as well as part of the expectation that a derivative will provide offsetting cash flows; therefore, the risk of counterparty default should be considered when evaluating effectiveness. ASC 815-20-35-14 through 35-18 provide guidance on considering the possibility of counterparty default in the evaluation of effectiveness and require that a reporting entity monitor the counterparty’s creditworthiness throughout the hedge period. If the likelihood that the counterparty will not default ceases to be probable, the reporting entity should discontinue hedge accounting.

Indicators of deteriorating credit quality that could result in the discontinuation of hedge accounting include:

- An increase in spreads on the counterparty’s credit default swap rates
- A downgrade of the counterparty’s credit rating by a rating agency

- A refusal by market participants to enter into new contracts with the counterparty
- A demand from market participants that the counterparty provide collateral for all new derivative contracts
- A widening of the credit spreads for the counterparty's public debt

In evaluating whether hedge accounting should be discontinued, a reporting entity should consider the specific facts and circumstances related to each counterparty and contract. In some cases, there may be mitigating circumstances (e.g., the counterparty's performance may be secured by collateral or a line of credit) that may indicate that hedge accounting can continue despite the decline in the counterparty's credit quality.

If a reporting entity determines that a cash flow hedging relationship no longer qualifies for hedge accounting, the overall change in fair value of the derivative instrument for that period, or subsequent to the triggering event if applicable, should be recognized in earnings. The reporting entity will also need to determine whether and when amounts deferred in accumulated other comprehensive income should be reclassified to earnings.

For example, in the case of a financially settled derivative instrument used to hedge physical purchases, the changes associated with the hedging instrument would have no impact on the probability of the forecasted transaction. However, in contrast, in assessing an all-in-one hedge in which the underlying transaction is delivery of the asset under the hedging instrument itself, a reporting entity should consider whether delivery is still likely to occur (which would result in continued deferral of amounts in accumulated other comprehensive income), or is now probable of not occurring (which would trigger immediate recognition of those deferred amounts in earnings).

3.5.4.2 Application of the long-haul method

The long-haul method is permitted to be used to evaluate effectiveness for any hedging relationship. ASC 815-20-25 does not prescribe a specific method for assessing hedge effectiveness but instead requires that a reasonable method based on the objective of management's risk management strategy and the nature of the hedging relationship be applied consistently to all similar hedges. This section addresses specific considerations in applying the long-haul method to commodity contracts.

Question 3-41

Can a reporting entity use spot prices in the evaluation of hedge effectiveness?

PwC response

Yes. A reporting entity may enter into a forward contract that it designates as the cash flow hedge of a forecasted commodity transaction. ASC 815-20-25-82(d) permits reporting entities to exclude the change in the fair value attributable to differences in spot prices and forward prices from effectiveness assessments.

ASC 815-20-25-82(d)

If the effectiveness of a hedge with a forward contract or futures contract is assessed based on changes in fair value attributable to changes in spot prices, the change in the fair value of the contract related to the changes in the difference between the spot price and the forward or futures price shall be excluded from the assessment of hedge effectiveness.

Therefore, in assessing effectiveness, reporting entities may choose to consider changes in the forward contract's fair value that are attributable only to changes in spot prices from one reporting period to the next. However, if this approach is used, some volatility in earnings will result, because the excluded portion of the change in fair value of the forward contract will be included in earnings as it occurs.

Variance reduction method

The variance reduction method is a form of long-haul effectiveness testing that allows a reporting entity to measure the extent to which the hedging instrument offsets the variance of the hedged item. This method is similar to regression analysis and is a statistical measure of the dispersion of the hedged item's possible values. The variance reduction test compares the statistical variance of the fair value of the combined position of the hedged item and the hedging instrument to the statistical variance of the fair value of the hedged item alone.

In applying this method, a reporting entity will need to determine and document how large a reduction of the variability of the hedged item is needed to conclude that the hedge is considered highly effective. Practice has developed to state that a variance reduction or epsilon of .80 or greater would be needed for a hedging relationship to be considered highly effective. A variance reduction of 0.80 means that the hedging instrument has reduced the dispersion of the hedged item to 20% based on the following formula:

$$\text{Variance reduction} = \epsilon \text{ (epsilon)} = 1 - s^2H / s^2Y$$

ϵ – Epsilon, the calculated variance reduction

s^2H – Sample variance of the hedged position (the hedging instrument and the hedged item), which is the sum of the squared variances of the hedged position

s^2Y – Sample variance of the hedged item, which is the sum of the squared variances of the hedged item alone

In calculating the sample variance of the hedged position and the hedged item, a reporting entity could use the historical monthly changes in prices for the hedged item and the derivative instrument. If the hedging relationship is deemed to be perfectly effective, the epsilon would be 1.0 because the numerator in the ratio (the dispersion of the combined hedged position) would be reduced to zero, thereby resulting in a ratio of zero. In practice, as long as the ratio is between .80 and 1.0, reporting entities generally conclude that the hedging relationship is considered highly effective.

Application example — variance reduction method of assessing hedge effectiveness

Simplified Example 3-33 illustrates application of the variance reduction method.

EXAMPLE 3-33**Hedge accounting — application of the variance reduction method**

Ivy Power Producers (IPP) owns the Camellia Generating Station, a 575 MW combined-cycle natural gas-fired generation facility. IPP is hedging forecasted purchases of natural gas for the Camellia power plant at Houston Ship Channel. IPP enters into a two-year NYMEX swap based on Henry Hub pricing to hedge its forecasted purchases of natural gas for Camellia.

The variance of the monthly changes in the Houston Ship Channel spot price for the 24-month period is 1.48. In addition, the variance of the monthly changes of the combined hedged position is 0.04.

Because the hedging instrument is priced at the Henry Hub location and the physical purchase of natural gas is priced at the Houston Ship Channel location, IPP's hedge is subject to ineffectiveness. IPP decides to use the variance reduction method to assess the effectiveness of the hedge.

Is the hedge highly effective?

Analysis

In applying the variance reduction method, IPP would calculate the sum of the variances of the combined hedged position and the sum of the variances of the hedged item based on historical data. Because this is a two-year hedge, the historical monthly prices for the prior 24 months would be used in the calculation. In this example, hedge effectiveness would be calculated as follows:

$$\text{Variance reduction} = \epsilon = 1 - 0.04 / 1.48 = 0.973$$

The hedging instrument offsets 97.3% of the variance of the hedged item, and, based on a critical value of 80% variance reduction, this calculation supports that the hedging relationship is expected to be highly effective. Similar to the other long-haul effectiveness methods, an ongoing assessment of effectiveness should be performed by calculating a prospective and retrospective effectiveness calculation at each financial reporting date, or at a minimum every three months.

3.5.4.3 Critical terms match method

Often, for commodity hedges, reporting entities seek to evaluate effectiveness using the critical terms match method, because it provides simplicity as compared to a quantitative assessment. A reporting entity may execute a commodity contract for which the terms perfectly match the hedged item or transaction such that the changes in cash flows attributable to the risk being hedged are expected to completely offset at the inception of the contract and on an ongoing basis. In the case of a commodity

contract, ASC 815 precludes the application of the shortcut method (which is only available for plain-vanilla interest rate swaps); however ASC 815-20-25-84 provides guidance on the use of a critical terms match method that can be used for commodity hedging relationships.

Excerpt from ASC 815-20-25-84

For example, an entity may assume that a hedge of a forecasted purchase of a commodity with a forward contract will be highly effective and that there will be no ineffectiveness to be recognized in earnings if all of the following criteria are met:

- a. The forward contract is for purchase of the same quantity of the same commodity at the same time and location as the hedged forecasted purchase.
- b. The fair value of the forward contract at inception is zero.
- c. Either of the following criteria is met:
 1. The change in the discount or premium on the forward contract is excluded from the assessment of effectiveness and included directly in earnings pursuant to paragraphs 815-20-25-81 through 25-83.
 2. The change in expected cash flows on the forecasted transaction is based on the forward price for the commodity.

If a reporting entity concludes that application of the critical terms match method of assessing effectiveness is appropriate, it is still required to assert and to document that the hedging instrument is expected to be perfectly effective in offsetting the hedged risk at the inception of the hedge.

The assessment should be updated quarterly; however, subsequent assessments can be limited to confirming that there have been no changes to the terms of the hedging instrument and forecasted transaction, as well as an updated analysis of potential for counterparty default. If there are changes or adverse developments, the reporting entity should measure ineffectiveness and quantitatively assess whether the hedge is expected to continue to be highly effective.

SEC observations

The SEC staff has expressed its view that known sources of variability that are not perfectly matched should be considered when evaluating hedge effectiveness (including when using the critical terms match method). The SEC staff further stated that when a reporting entity has inappropriately assumed there is no ineffectiveness in a relationship and did not measure the amount of the ineffectiveness, the error should be quantified as if the designated hedging relationship did not qualify for hedge accounting under ASC 815 (i.e., the hedge accounting should be reversed from inception, potentially leading to restatement if the impact is material).

The SEC staff expects that registrants will not ignore such sources of potential ineffectiveness but rather will prepare a quantitative analysis to support their assertions about hedge effectiveness. Specifically, where there are known sources of potential ineffectiveness, the SEC staff expects that a quantitative analysis will demonstrate that the hedge will nevertheless be expected to always be effective and that any ineffectiveness would be *de minimis*.

Therefore, as part of critical terms match hedging, reporting entities should:

- Identify all sources of potential ineffectiveness (if any).
- Document a basis for concluding that the relationship is nevertheless highly effective.
- Demonstrate that reasonably expected amounts of ineffectiveness are and will be *de minimis*.

These activities are further described below. The SEC staff did not prescribe the method(s) to be used to perform this analysis; ASC 815 allows considerable latitude in the manner in which hedge effectiveness can be supported. A reporting entity should determine the appropriate methodology based on its specific facts and circumstances. The analysis should be updated as necessary to address any changes impacting the initial analysis.

Without supporting analysis, the SEC staff believes it is inappropriate to assume that there is no ineffectiveness in a hedging relationship when there is a known source of variability that has not been perfectly matched. However, the SEC staff has accepted the application of hedge accounting in situations where the registrant has (1) identified the source of ineffectiveness; (2) evaluated the possible impacts and sufficiently demonstrated that the possible ineffectiveness would be *de minimis*; and (3) documented a quantitative analysis that demonstrated a continuing and realistic expectation of effectiveness. As a result, we recommend that reporting entities perform and document the following analyses:

Identify all sources of potential ineffectiveness in a hedging relationship

Common potential sources of ineffectiveness in commodity hedges:

- *Differences in settlement date*

Differences in settlement date will occur when payments related to the derivative contract occur on a different date than those associated with the hedged transaction. For example, a financial transaction may settle on the fifth day of the month while a physical purchase may settle on the twentieth day.

□ *Basis differences*

Basis differences occur when a derivative instrument is linked to a specified index price and the underlying hedged transaction is priced using a different index. These differences can occur as a result of differences in location (e.g., Houston Ship Channel versus Henry Hub) or time period (e.g., monthly versus daily).

In addition, the SEC staff has focused on potential ineffectiveness arising from differences in maturity dates and settlement/payment dates between the hedging instrument and the hedged forecasted transaction. The SEC staff believes that a difference between the hedged forecasted transaction date and the derivative instrument's maturity, or a difference between the settlement dates of the forecasted transaction and the derivative instrument, are known potential sources of variability (i.e., ineffectiveness) that should be addressed in the registrant's hedge documentation.

Document the basis for concluding that the hedging relationship is nevertheless expected to be highly effective and that expected amounts of ineffectiveness will be de minimis (in a critical terms match hedge)

As noted above, the SEC staff expects registrants to identify all potential sources of ineffectiveness in a hedging relationship. However, the registrant has some flexibility in the manner in which such differences are addressed. The overall objective is to perform an analysis (in part, quantitatively) that supports the registrant's underlying assertion that the hedging relationship was and will be expected to be highly effective, and that the aggregate and periodic amounts of any ineffectiveness would be *de minimis* (thus supporting the use of the critical terms match method). The reporting entity should determine the appropriate approach and level of analysis based on its specific facts and circumstances.

Update conclusion as necessary

After the initial assessment, on a quarterly basis, reporting entities should review their documentation, affirm that the underlying assertions are still appropriate, and, if necessary, update their prior analyses. Reporting entities will need to determine the appropriate amount of quantitative analysis on a quarterly basis, based on the specific facts and circumstances of their hedging relationships. In some cases, it may be appropriate to update the quantitative analysis performed at inception based on current data; in other situations, it may be sufficient to review the original assertion and adjust the analysis as applicable for any changes in the factors that support the initial conclusion. The quarterly procedures related to ineffectiveness should be documented as part of the critical terms match quarterly documentation.

Application examples – critical terms match method of evaluating hedge effectiveness

The following simplified examples illustrate considerations in applying the critical terms match method, including sample hedge documentation as well as the evaluation and documentation of potential sources of ineffectiveness.

EXAMPLE 3-34

Hedge accounting — critical terms match method of evaluating hedge effectiveness (monthly spot prices)

In October 2014, Ivy Power Producers enters into a swap for the purchase of 10,000 MMBtus per day of natural gas at a fixed price of \$2.00/MMBtu at SoCal Border (a market hub for natural gas located in California) for the month of August 2015. Under the terms of the swap, IPP will pay \$2.00 and will receive the monthly spot price at SoCal Border. The swaps are executed in anticipation of the forecasted purchase of at least 10,000 MMBtus per day of natural gas at the same location during the same period, at the monthly spot price. The hedging instrument will settle on July 31, 2015 and IPP will pay or receive the settlement amount on the fifth day of August 2015. IPP will pay for its physical purchases on the twentieth day of September 2015.

In this example, the hedging strategy is to hedge the changes in total cash flows by fixing the natural gas price through the fixed-for-floating index swap for the quantity needed to generate power. Although most of the critical terms (i.e., location, quantity, and price) match between the swap and the forecasted transaction, there is a difference in settlement dates because the financial swap and physical commodity purchase will settle on different dates, resulting in ineffectiveness arising out of the time difference in the value of cash.

Does the difference in settlement dates have a more than a *de minimis* impact?

Analysis

Any source of potential ineffectiveness (even a difference in settlement date of a few days) should be considered in IPP's hedge documentation and effectiveness assessment. A brief quantitative analysis should be included in the original hedging documentation.

The time value of the maximum expected settlement amount on the hedge would be calculated as follows:

- Total quantity: 10,000 MMBtus per day * 30 days = 300,000 MMBtus
- Maximum expected monthly index price: \$4/MMBtu (based on historical averages)
- Maximum expected settlement amount: 300,000 MMBtus * [\$4 (maximum variable price) – \$2 (fixed price)] = \$600,000
- Maximum discount rate: 4% (based on current rates and duration of the hedge)
- Maximum impact: \$3,000 (time value of money calculation based on 45 day difference in settlement dates)

The potential maximum impact is *de minimis* based on the time value of money compared to the total value of the hedge transaction. The analysis could also be performed on a periodic basis to support similar hedges (e.g., the analysis could be performed quarterly for all similar hedges executed in the quarter); however, the

hedge documentation for each hedge should clearly reference the analysis and document the conclusion.

Alternatively, this, or a similar analysis of settlement differences for similar hedges could be performed on a global basis, such as through an analysis of average total monthly settlements. Reporting entities have flexibility in performing their analysis; however, the conclusion should be supported by a quantitative analysis for these types of differences.

In addition, IPP is still required to update its hedge effectiveness evaluation at least quarterly. However, when the critical terms match approach is used, the subsequent assessment of effectiveness can be performed by verifying and documenting that there has been no change in the critical terms of the hedging instrument or forecasted transaction during the period. IPP should consider if there have been any changes in circumstances or market interest rates that necessitate an update to its time value analysis. Finally, IPP should also specifically consider and document whether there have been any adverse developments with respect to counterparty credit risk during the period (see UP 3.5.2.2 *Counterparty creditworthiness*).

EXAMPLE 3-35

Hedge accounting — critical terms match method of evaluating hedge effectiveness (daily spot prices)

Assume the same facts as in Example 3-34, except that Ivy Power Producers will settle the forecasted physical transaction using the daily spot prices instead of monthly prices. In this example, the hedging strategy is to hedge the changes in total cash flows by fixing the natural gas price as of the beginning of the transaction month. Note—the mismatch in settlement dates described in Example 3-34 also applies here. However, this difference has been ignored in this example to focus on other effectiveness issues.

In this fact pattern, the critical terms relating to location and timing match; however, the pricing of the swap (based on the monthly index) does not match that of the forecasted transaction which will be settled using the daily spot prices. A daily/monthly pricing mismatch represents a basis difference. Although the forecasted purchases occur within the same month, there is a difference in maturity date between the hedging instrument (matures on August 1, 20X2) and the forecasted transaction (forecasted to occur each day throughout the month of August 20X2 with settlement in September 20X2). The difference in maturity date and the difference in the settlement index (monthly index for the hedging instrument compared with daily index for the physical transactions) will create ineffectiveness in the hedging relationship.

How should IPP determine the amount of ineffectiveness?

Analysis

As a result of the basis mismatch, IPP should evaluate whether use of the critical terms match method is appropriate. If the critical terms match method is used, IPP would be expected to perform a quantitative analysis to support the assertion that any ineffectiveness due to the basis mismatch would be *de minimis*. It may be more appropriate to perform a long-haul assessment of effectiveness, essentially evaluating

the relationship between the daily natural gas prices versus the monthly prices at the given location.

There are several ways reporting entities may perform this analysis, including:

- Regression analysis—Performing a regression of daily versus monthly prices using a complete set of data or the 30 most recent observable prices, as well as using outlier prices from certain periods (e.g., if a major weather event has caused unusual, large swings in pricing).
- Dollar offset method—Calculating the ratio of the sum of changes in the spot prices versus the sum of changes in the forward prices.
- Variance reduction method—Subtracting the ratio of variances of cash flows under the spot price exposure and the hedged portfolio from “1.”

Reporting entities should carefully evaluate hedges established using swaps or financial forward contracts based on a monthly index to hedge forecasted purchases that will occur at daily spot prices. Some markets may have distortions between daily and monthly prices, which could negatively impact the effectiveness evaluation.

3.6 Other products

This section illustrates the application of the derivative accounting framework to certain common types of commodity contracts entered into by reporting entities in the utility and power industry. Figure 3-15 summarizes the sample contracts and cross-references to the related discussion. The analysis of each of these products assumes the contract does not contain a lease.

The summary analysis performed in this section or as referenced in Figure 3-15 is provided for informational purposes only to assist reporting entities in identifying the key considerations for analyzing these types of contracts. Notwithstanding the analysis provided for each type of product described, reporting entities should evaluate each transaction or contract based on its individual facts and circumstances, which could result in different conclusions than described herein.

Figure 3-15
Common types of commodity contracts

Contract type	Derivative?	Key considerations
Ancillary services (UP 4.4)	It depends	<ul style="list-style-type: none"> □ Ancillary services vary depending on the location and market; individual contracts should be evaluated to determine if they meet the net settlement criterion.

Contract type	Derivative?	Key considerations
Auction revenue right (ARR) (UP 4.3.2)	Generally, yes	<ul style="list-style-type: none"> □ ARR are financial instruments that entitle holders to the proceeds, or require them to pay the charges, from the sale of Financial Transmission Rights in an annual auction (based on price differences between the point of receipt (source) and the point of delivery (sink) nodes)
Capacity contracts (power plant capacity) (UP 3.6.1)	Generally, no	<ul style="list-style-type: none"> □ Capacity contracts are usually physically settled and lack the net settlement characteristic; reporting entities should monitor markets for changes to determine if the net settlement criterion is met (see discussion of regional transmission organization-related capacity contracts below).
Coal contracts (UP 3.6.2)	It depends	<ul style="list-style-type: none"> □ Forward contracts for purchases and sales of coal may meet the definition of a derivative depending on the type of coal and the markets. □ Markets are continuing to change; reporting entities should monitor markets for changes to determine if the net settlement criterion is met.
Emission allowances (forward contracts) (UP 6.3.2.1)	It depends	<ul style="list-style-type: none"> □ Forward contracts for emission allowances may meet the definition of a derivative, depending on the type of allowances and the markets. □ Markets are changing as a result of ongoing regulatory developments; reporting entities should monitor markets for changes to determine if the net settlement criterion is met.
Financial transmission rights (FTR) (UP 4.4.3)	Yes	<ul style="list-style-type: none"> □ FTRs are financial instruments that entitle the holder to receive compensation for transmission congestion charges that arise when the transmission grid is congested in the day-ahead market.
Natural gas capacity agreements (transportation) (UP 5.5)	Generally, no	<ul style="list-style-type: none"> □ Contracts are usually physically settled and lack the net settlement characteristic. □ Some markets are developing; reporting entities should monitor markets for changes to determine if the net settlement criterion is met.

Contract type	Derivative?	Key considerations
Natural gas park and loan agreements (UP 5.4)	Generally, an embedded derivative exists	<ul style="list-style-type: none"> □ Once the transporter borrows the natural gas placed in storage, it will record a liability for the return of the natural gas at a future date; the liability includes an embedded derivative that should be separated and recognized at fair value.
Natural gas storage (UP 5.2)	Generally, no	<ul style="list-style-type: none"> □ Contracts are usually physically settled and lack the net settlement characteristic. □ Reporting entities should monitor markets for changes to determine if the net settlement criterion is met.
Natural gas virtual storage agreements (UP 5.3)	Generally, an embedded derivative exists	<ul style="list-style-type: none"> □ Agreements include an embedded derivative that should be separated from the host asset/liability contract and recognized at fair value by both the shipper and the transporter, respectively.
Reliability pricing model (RPM) contracts (UP 4.3.1)	Generally, no	<ul style="list-style-type: none"> □ RPM contracts are usually physically settled and lack the net settlement characteristic; reporting entities should monitor markets for changes to determine if the net settlement criterion is met. □ Capacity contracts in other regional transmission organizations would generally be evaluated similarly to RPM contracts, however each type of contract should be individually analyzed.
Renewable energy credits (forward contracts) (UP 7.5.1.2)	Generally, no	<ul style="list-style-type: none"> □ Contracts are usually physically settled and lack the net settlement characteristic. □ Some markets are developing, and reporting entities should monitor markets for changes to determine if the net settlement criterion is met.
Requirements contracts (UP 3.2.1.1)	It depends	<ul style="list-style-type: none"> □ The evaluation is contract specific and will generally depend on whether there is a notional amount.
Retail contracts for sale of power (UP 3.6.3)	It depends	<ul style="list-style-type: none"> □ Contracts may include other products or services that typically do not meet the definition of a derivative. □ The evaluation of the power component is contract specific and typically will depend on whether the contract has a notional amount.

Contract type	Derivative?	Key considerations
Seasonal power exchange contracts (UP 3.6.4)	It depends	<ul style="list-style-type: none"> □ Seasonal power exchange contracts typically result in the physical delivery of power at one time or location in exchange for power at a future point in time and/or in a different location. □ The key question is whether the contract has a notional amount; the assessment may sometimes change during the life of the contract.
Tolling agreements (UP 3.6.5)	It depends	<ul style="list-style-type: none"> □ Tolling agreements often specify a source of supply and lease accounting may be applicable. □ If lease accounting does not apply, the contract generally should be evaluated as a hybrid instrument; the key issue is usually whether the contract has a notional amount.
Transmission (UP 3.6.6)	Generally, no	<ul style="list-style-type: none"> □ Contracts are usually physically settled and lack the net settlement characteristic; reporting entities should monitor markets for changes to determine if the net settlement criterion is met.
Uranium (UP 14.2.2)	Generally, no	<ul style="list-style-type: none"> □ Contracts are usually physically settled and lack the net settlement characteristic; reporting entities should monitor market changes to determine if the net settlement criterion is met.
Water (UP 3.6.7)	Generally, no	<ul style="list-style-type: none"> □ Contracts are usually physically settled and lack the net settlement characteristic.
Weather (UP 3.3.2.1 and UP 3.6.8)	No; however, fair value accounting may apply	<ul style="list-style-type: none"> □ Accounting for non-exchange-traded weather derivatives will depend on the type of contract (e.g., forward or option) and whether contracts were executed as part of trading activities.

3.6.1 Capacity contracts (power plant capacity)

In general, contracts for capacity outside of a regional transmission organization without explicit net settlement terms do not meet the definition of a derivative. See UP 3.4.3 for analysis of capacity sold together with power and UP 4 for information on contracts in a regional transmission organization environment. Figure 3-16 highlights the derivative evaluation for a typical capacity contract; however, each contract should be evaluated based on its individual facts and circumstances.

Figure 3-16

Does a capacity contract meet the definition of a derivative?

Guidance	Evaluation	Comments
Notional amount and underlying	Met	<ul style="list-style-type: none"> □ Notional (quantity of capacity) and underlying (the price of the capacity) are usually specified.
No initial net investment	Met	<ul style="list-style-type: none"> □ No initial net investment is typically required.
Net settlement	Generally not met	<ul style="list-style-type: none"> □ Capacity contracts are generally physically settled; implicit net settlement is not typical but should be evaluated. □ Currently, there is no market mechanism to permit net settlement and no active markets for spot sales of capacity; however, markets should be monitored.

In general, we would not expect a contract for capacity to be accounted for as a derivative because it fails the net settlement criterion.

ASC 815-10-15-83(c)

Net settlement. The contract can be settled net by any of the following means:

1. Its terms implicitly or explicitly require or permit net settlement.
2. It can readily be settled net by a means outside the contract.
3. It provides for delivery of an asset that puts the recipient in a position not substantially different from net settlement.

Factors to consider in assessing whether capacity contracts executed outside of a regional transmission organization meet the net settlement criterion are further discussed in the following paragraphs. See UP 3.2.3 for further information on overall application of the net settlement criterion.

Net settlement under contract terms

When evaluating whether the net settlement criterion is met, a reporting entity should first consider whether the contract explicitly or implicitly provides for net settlement of the entire contract. Forward contracts for capacity typically require physical delivery and do not permit explicit net settlement. However, the contract terms should be carefully reviewed for any terms or liquidating damage provisions that the contract could be net settled.

Net settlement through a market mechanism

In this form of net settlement, one of the parties is required to deliver an asset, but there is an established market mechanism that facilitates net settlement outside the contract. ASC 815-10-15-110 through 15-116 provide indicators to consider in assessing whether an established market mechanism exists. A key aspect of a market mechanism is that one of the parties to the agreement can be fully relieved of its rights and obligations under the contract. We are not aware of any U.S. capacity markets such that a provider has the ability to be relieved of its full rights and obligations under a previously executed contract.

Net settlement by delivery of an asset that is readily convertible to cash

Whether there is an active spot market for the particular product being sold under the contract is the key factor in assessing whether the asset is readily convertible to cash. Current market conditions should always be considered in this analysis. To be deemed an active spot market, a market must have transactions with sufficient frequency and volume to provide pricing information on an ongoing basis. In addition, quoted prices from that market will be readily available on an ongoing basis. See UP 3.2.3.3 for further information on the determination of whether a market is active. Based on the current structure of the markets, we are not aware of any U.S. active spot markets for capacity.

Overall conclusion

We are not aware of a market mechanism or active spot market for capacity and thus we believe that derivative accounting is generally not applicable to these contracts. However, a reporting entity should evaluate all facts and circumstances in concluding on the appropriate accounting for a specific capacity contract. In addition, a reporting entity should monitor its conclusion periodically as markets may evolve, potentially rendering this type of contract a derivative. Reporting entities also should evaluate the contract to determine if there are any embedded derivatives that require separation.

Reporting entities may also consider conditionally designating capacity contracts under the normal purchases and normal sales scope exception if physical delivery is probable throughout the life of the contract and the other criteria for application of this exception are met (ASC 815-10-15-22 through 15-51 as applicable). If a conditionally designated normal purchases and normal sales contract meets the definition of a derivative at a later date, it would be accounted for as a normal purchases and normal sales contract from the time the contract becomes a derivative. Absent such a designation, the reporting entity would be required to record the contract at its fair value at the time it becomes a derivative. See UP 3.3.1 for further information on the normal purchases and normal sales scope exception.

3.6.2 Coal contracts

Physical forward contracts for the purchase or sale of coal may meet the definition of a derivative instrument. The key consideration in determining if a coal contract meets the definition of a derivative instrument is whether the contract meets the net settlement criterion. Figure 3-17 highlights the derivative evaluation for a typical coal

contract; however, each contract should be evaluated based on its individual facts and circumstances.

Figure 3-17

Does a coal contract meet the definition of a derivative?

Guidance	Evaluation	Comments
Notional amount and underlying	Met	<ul style="list-style-type: none"> □ Notional (quantity of coal) and underlying (price of the coal) are usually specified.
No initial net investment	Met	<ul style="list-style-type: none"> □ No initial net investment is typically required.
Net settlement	It depends	<ul style="list-style-type: none"> □ Contracts for coal are usually physically settled; implicit net settlement is not typical but should be evaluated. □ These contracts may result in physical delivery of an asset that is considered readily convertible to cash; however, the reporting entity should specifically evaluate based on the delivery location.

We would expect financially settled forward contracts for coal to meet the definition of a derivative and such contracts are not further discussed herein. In evaluating physically settled contracts for coal, the key question typically is whether the contract has the characteristic of net settlement.

ASC 815-10-15-83(c)

Net settlement. The contract can be settled net by any of the following means:

1. Its terms implicitly or explicitly require or permit net settlement.
2. It can readily be settled net by a means outside the contract.
3. It provides for delivery of an asset that puts the recipient in a position not substantially different from net settlement.

Factors to consider in assessing whether coal contracts meet the net settlement criterion are further discussed in the following paragraphs. See UP 3.2.3 for further information on overall application of the net settlement criterion.

Net settlement under contract terms

When evaluating whether the net settlement criterion is met, a reporting entity should first consider whether the contract explicitly or implicitly provides for net settlement of the entire contract. Forward contracts for coal typically require physical delivery and do not permit explicit net settlement. However, the type of contract and the terms

should be carefully reviewed for any implicit net settlement terms or liquidating damage provisions that may imply that the contract could be net settled.

Net settlement through a market mechanism

In this form of net settlement, one of the parties is required to deliver an asset, but there is an established market mechanism that facilitates net settlement outside the contract. ASC 815-10-15-110 through 15-116 provide indicators to consider in assessing whether an established market mechanism exists. A key aspect of a market mechanism is that one of the parties to the agreement can be fully relieved of its rights and obligations under the contract. We are not aware of any U.S. coal markets such that a provider has the ability to be relieved of its full rights and obligations under a previously executed contract.

Net settlement by delivery of an asset that is readily convertible to cash

Whether there is an active spot market for the particular product being sold under the contract is the key factor in assessing whether an asset is readily convertible to cash. To be deemed an active market, a market must have transactions with sufficient frequency and volume to provide pricing information on an ongoing basis. In addition, quoted prices from that market will be readily available on an ongoing basis. The analysis should consider the type of coal being sold in the contract and whether the transportation costs are at a level to support an assertion that the coal is readily convertible to cash (e.g., it may be too costly to transport the coal from the mine to a liquid trading hub). There may be some markets and mines where reporting entities have concluded that there is sufficient frequency and volume to support a conclusion that an active spot market exists for a particular type of coal and trading location. See UP 3.2.3.3 for information on evaluating the readily-convertible-to-cash criterion for commodities, including how to evaluate costs to transport a commodity to a liquid trading location.

Overall conclusion

A contract for coal may meet the net settlement criterion, depending on the type of contract and the related markets. Reporting entities should revisit this conclusion periodically as markets may evolve, potentially changing the conclusion. If a reporting entity concludes a coal contract does not meet the definition of a derivative because it fails the net settlement criterion, it may also consider conditionally designating the contracts under the normal purchases and normal sales scope exception if physical delivery is probable throughout the life of the contract and the other criteria for application of this exception are met. If a conditionally designated normal purchases and normal sales contract meets the definition of a derivative at a later date, it would be accounted for as a normal purchases and normal sales contract from the time the contract becomes a derivative. See UP 3.3.1 for further information.

3.6.3 Retail electricity contracts

Retail electricity contracts typically result in the physical delivery of electric energy to an end user, such as a retail consumer or direct access customer. Retail contracts for delivery of electric energy may meet the definition of a derivative, if the contract has a

notional amount and the net settlement criterion is met. Figure 3-18 highlights the derivative evaluation for a typical retail electricity contract; however, each contract should be evaluated based on its individual facts and circumstances.

Figure 3-18

Does a retail electricity contract meet the definition of a derivative?

Guidance	Evaluation	Comments
Notional amount and underlying	It depends	<ul style="list-style-type: none"> □ Contracts are often requirements contracts, which may or may not specify a minimum quantity; see UP 3.2.1.1 for information on how to evaluate a requirements contract. □ Some contracts may specify a fixed quantity and would therefore have a notional; the underlying is the price of power in the contract.
No initial net investment	Met	<ul style="list-style-type: none"> □ No initial net investment is typically required.
Net settlement	It depends	<ul style="list-style-type: none"> □ These contracts may result in physical delivery of energy that is considered readily convertible to cash; however, the reporting entity should specifically evaluate based on the delivery location (see UP 3.2.3.3 <i>Access to an active market</i>).

Although this type of contract is typically structured to meet the needs of one of the parties to the contract (i.e., a requirements contract), it may still meet the definition of a derivative. A reporting entity will need to analyze the terms of the contract to determine whether the contract contains a notional amount and whether it meets the criterion of net settlement.

Notional amount

In evaluating a retail electricity sales agreement, the parties should consider whether the contract contains a notional amount. In particular, many retail electricity contracts are requirements contracts that are designed to meet the needs of the retail customer, with purchases limited to the amount needed for the customer's own use. In such cases, unless the contract specifies a minimum quantity, there would be no notional amount. However, if the contract does not limit purchases for the off-taker's own use, the contract may have a notional amount and further evaluation under the net settlement criteria will be required. See UP 3.2 for further information on evaluating whether a contract has a notional amount.

Net settlement

As further discussed in ASC 815-10-15-83(c), there are three possible forms of net settlement: net settlement under the contract terms, net settlement through a market mechanism, and net settlement because the contract requires delivery of an asset that is readily convertible to cash. Retail electricity sales agreements typically require physical delivery and do not permit explicit net settlement. Furthermore, because the notional, if any, is not usually a standard market quantity, there would be no market mechanism for net settlement. Therefore, the key question is whether the parties to the contract have access to a market where power is readily convertible to cash. This assessment will depend on the price of transmission to access a liquid market hub from the delivery point (see UP 3.2.3.3 *Access to an active market*). The fact that one of the parties to the contract (i.e., the retail customer) may not have the knowledge to access the market would not change the conclusion that the contract is readily convertible to cash.

Overall conclusion

A retail electricity sales agreement may meet the definition of a derivative, depending on whether the contract has a notional amount and the energy can be sold in a liquid market.

Application of the normal purchases and normal sales scope exception

Retail power sales contracts that meet the definition of a derivative may be designated as normal purchases and normal sales if delivery is probable throughout the term of the contract and all other requirements are met. To designate the contract as a normal purchase or normal sale, the reporting entity will need to support the assertion that delivery is probable and that the other criteria for designation as normal are met (see UP 3.3.1).

In some situations, a retail contract for a fixed quantity may exceed the off-taker's forecasted needs in some hours of the day or periods during the year and as a result, the power in those periods would not be delivered. In such cases, the contract would not qualify for the normal purchases and normal sales scope exception for either party because physical delivery is not probable, even if the excess quantities are not significant in relation to the overall contract. In accordance with ASC 815-10-15-35, physical delivery must be "probable at inception and throughout the term of the individual contract." As such, a contract that may settle net in some periods would not meet this assertion.

Additionally, if a reporting entity concludes that a retail electricity sales agreement does not meet the definition of a derivative because it fails the net settlement criterion, it may also consider conditionally designating the contract under the normal purchases and normal sales scope exception if physical delivery is probable throughout the life of the contract and the other criteria for application of this exception are met. If a conditionally designated normal purchases and normal sales contract meets the definition of a derivative at a later date, the contract would be accounted for as a normal purchases and normal sales contract from the time it becomes a derivative. Absent such a designation, the reporting entity would be

required to initially fair value the contract at the time the contract is determined to be a derivative. See UP 3.3.1 for further information on the normal purchases and normal sales scope exception.

Multiple products

Retail electricity contracts may also include ancillary services or other products such as capacity, renewable energy credits, energy-efficiency equipment, demand-side management, or maintenance. Retail contracts that include multiple deliverables would not meet the definition of a derivative in their entirety unless the contract has explicit or implicit net settlement provisions. However, the reporting entity should analyze the contract to determine if it includes one or more embedded derivatives that require separation from the host contract. Figure 3-19 summarizes this analysis.

Figure 3-19

Does a retail electricity contract with multiple products and/or services include an embedded power derivative that requires separation?

Guidance	Evaluation	Comments
Economic characteristics of the embedded are not clearly and closely related to the host	Met	<ul style="list-style-type: none"> □ The host contract is determined based on the nonderivative elements; typically the host includes an energy services agreement that provides for the execution of the different specified deliverables (see UP 3.4.3).
Hybrid instrument is not remeasured at fair value under otherwise applicable U.S. GAAP	Met	<ul style="list-style-type: none"> □ The overall contract is not remeasured at fair value in its entirety.
A separate instrument with the same terms as the embedded derivative would be a derivative instrument subject to ASC 815	It depends	<ul style="list-style-type: none"> □ The key questions are whether the contract has a notional and access to a liquid market. □ The derivative may be eligible for the normal purchases and normal sales scope exception and if elected, no separation is required.

In evaluating this type of contract, the reporting entity should first assess whether the energy component is clearly and closely related to the other products or services in the contract. A retail electricity contract that includes more than the sale of energy often provides for the delivery of multiple products or services at different times. Furthermore, although some of the contractual elements may impact power consumption (e.g., energy-efficient equipment, demand-side management services), the value and cost of these products or services are separate from the energy. As such, the energy component generally is not clearly and closely related to these other products and services due to their nature, and bifurcation of the contract would be

required. See UP 3.4.3 for further information on the clearly and closely related assessment for contracts with multiple products.

The determination of whether a separate instrument with the same terms would meet the definition of a derivative for the energy component is performed in a manner consistent with the evaluation of a stand-alone power agreement.

3.6.4 *Seasonal power exchange contracts*

Seasonal power exchange contracts typically result in the physical delivery of electric energy over a period of time or at a certain location in exchange for physical receipt of energy at a future point in time and/or in a different location. Seasonal power exchanges may be executed to enhance system reliability or to help utilities balance their available generation resources with their load requirements. These contracts are often highly structured and the derivative determination may be complex, with varying conclusions depending on the specific contract terms. In addition, the assessment may change over the various stages of the contract. Figure 3-20 highlights the derivative evaluation for a typical seasonal power exchange contract; however, each contract should be evaluated based on its individual facts and circumstances.

Figure 3-20

Does a seasonal power exchange contract meet the definition of a derivative?

Guidance	Evaluation	Comments
Notional amount and underlying	It depends	<ul style="list-style-type: none"> □ Contracts that specify a fixed quantity of energy to be exchanged generally have a notional amount, if the quantity is enforceable. □ Some exchanges may allow initial delivery at the option of one of the parties; this optionality may impact the notional analysis.
No initial net investment	Met	<ul style="list-style-type: none"> □ No initial net investment is typically required prior to the initial delivery; see further considerations below.
Net settlement	Usually met	<ul style="list-style-type: none"> □ These contracts generally result in physical delivery of energy that is considered readily convertible to cash; delivery location however, should be considered.

Factors to consider in assessing the accounting for a seasonal power exchange are further discussed below. See UP 3.2.1 and UP 3.2.3 for further information on the determination of notional amounts and evaluation of embedded derivatives, respectively.

Notional amount

Determining whether a contract has a notional amount is often the most difficult aspect of evaluating a seasonal exchange contract, particularly if the contract includes more than one exchange or some form of optionality. Reporting entities should evaluate all aspects of the contract, such as the initial delivery provisions, return requirements, and any provisions for net settlement or optional repayment in lieu of return of energy.

Embedded derivative

Seasonal power exchange contracts that specify the quantity, delivery period, and delivery location for both the initial delivery and the return of energy have a notional amount and should be accounted for as a derivative. Upon initial delivery, the receiving utility has a payable for the return of power, while the delivering party has a receivable. The asset or liability is a hybrid instrument comprising a payable or receivable and a forward contract for the future delivery or receipt of energy. The value of the receivable or payable will fluctuate with power price changes. As a result, once the initial leg of the power exchange is delivered, the remainder of the contract is a hybrid instrument with an embedded derivative (the forward purchase or sale of power) that should be separated.

Figure 3-21

Does a seasonal exchange include an embedded derivative after initial delivery occurs?

Guidance	Evaluation	Comments
Economic characteristics of the embedded are not clearly and closely related to the host	Met	<ul style="list-style-type: none"> □ The host contract is a receivable or payable; changes in the price of power are not clearly and closely related to a debt host.
Hybrid instrument is not remeasured at fair value under otherwise applicable U.S. GAAP	Met	<ul style="list-style-type: none"> □ The receivable or liability is not remeasured at fair value in its entirety.
A separate instrument with the same terms as the embedded derivative would be a derivative instrument subject to ASC 815	Met	<ul style="list-style-type: none"> □ A firm commitment to purchase or sell power would generally meet the definition of a derivative. □ The embedded derivative may be eligible for the normal purchases and normal sales scope exception and if elected, no separation is required.

Even if the contract in its entirety does not meet the definition of a derivative, derivative accounting may be applicable after the initial energy is delivered.

Normal purchases and normal sales scope exception

Seasonal power exchange contracts are usually intended to help balance load requirements, provide system reliability, or meet other operational needs. Therefore, the initial leg of the transaction, as well as the embedded derivative will often qualify for the normal purchases and normal sales scope exception (see the response to Question 3-22). However, if the contract includes optionality with respect to timing and volumes of delivery, or net settlement provisions in lieu of return of energy as an option of one of the parties, the embedded forward purchase or sale (created after the initial delivery) would not qualify for the normal purchases and normal sales scope exception if physical delivery is not probable.

3.6.5 Tolling agreements

In a typical tolling agreement, one party provides the fuel source for a specific power generation facility in exchange for the energy and capacity from the power plant. A plant-specific contract should initially be assessed to determine if it contains a lease (see UP 1 and UP 2). If the contract does not contain a lease, the reporting entity should next assess whether it is a derivative in its entirety. A reporting entity should then consider whether the contract contains any embedded derivatives requiring separation from the host contract (unless the contract is a derivative in its entirety). The following analysis assumes that the tolling agreement is not a lease.

The determination of whether a tolling agreement is a derivative or contains one or more embedded derivatives will depend on the terms of the contract as well as the market in which delivery is required. Key questions to consider in the evaluation of this type of contract are highlighted below; however, individual contracts will require further evaluation based on the specific contract terms. Tolling agreements are not standard and the underlying markets vary significantly across the United States.

Does the contract have a notional amount?

The determination of whether the contract has a notional amount will depend on the specific terms of the contract. Some tolling agreements are for a specified quantity of energy and capacity, while other contracts may be for all or a portion of the capacity and production from a specific plant. In such cases, the reporting entity will need to consider the default provisions and other relevant terms to determine if there is a notional. See UP 3.2.1 for further information on the assessment of notional amount. If the contract does not have a notional amount, no further evaluation under the derivative framework is required.

Does the contract meet the net settlement criterion?

The key factor in determining whether the contract is a derivative in its entirety is whether the contract has the characteristic of net settlement. As further discussed in ASC 815-10-15-83(c), there are three possible forms of net settlement: net settlement under the contract terms, net settlement through a market mechanism, and net settlement because the contract requires delivery of an asset that is readily convertible to cash.

Most tolling agreements do not include explicit net settlement provisions and currently there are no market mechanisms to net settle a long-term power supply contract in the United States. However, the evaluation of whether the contract requires delivery of an asset that is readily convertible to cash will depend on the specific local market for power. In many parts of the United States, the markets for power and capacity have been unbundled and there is no market for a combined capacity and power product. However, in other situations, the standard power product may include bundled capacity. In such cases, the reporting entity may conclude that the contract meets the definition of a derivative, if all applicable criteria are met.

We are not aware of a market mechanism or active spot market for tolling agreements and thus we believe that derivative accounting is generally not applicable to these contracts as a whole. However, as noted above, there may be circumstances where the market standard power product includes bundled capacity, resulting in a conclusion that the contract is a derivative in its entirety. If the agreement is not a derivative in its entirety, the reporting entity should perform further evaluation to determine if the contract includes one or more embedded derivatives.

Does the contract contain one or more embedded derivatives?

The next step in the analysis is to determine if the power or capacity supplied under the agreement is an embedded derivative that requires separation from the host contract. The analysis for capacity contracts will be similar to that for a stand-alone contract for capacity as discussed in UP 3.6.1. Figure 3-22 summarizes the key considerations for the separate power component in a typical tolling agreement. However, each contract should be evaluated based on its individual facts and circumstances.

Figure 3-22

Does a tolling agreement include an embedded power derivative that requires separation?

Guidance	Evaluation	Comments
Economic characteristics of the embedded are not clearly and closely related to the host	Met	□ The host contract is a capacity agreement (assuming capacity does not meet the definition of a derivative; if capacity is a derivative, the contract may be a compound derivative) (see UP 3.4.3).
Hybrid instrument is not remeasured at fair value under otherwise applicable U.S. GAAP	Met	□ The overall contract is not remeasured at fair value.

Guidance	Evaluation	Comments
A separate instrument with the same terms as the embedded derivative would be a derivative instrument subject to ASC 815	It depends	<ul style="list-style-type: none"> □ See UP 3.2.1 and UP 3.2.3 for further information on determination of notional and assessment of the net settlement criterion, respectively. □ The embedded derivative may be eligible for the normal purchases and normal sales scope exception and if elected, no separation is required.

If the energy portion of the contract is an embedded derivative that requires separation, it may be eligible for designation as a normal purchase or normal sale or as a hedge, if the applicable criteria are met.

3.6.6 *Transmission contracts*

Bilateral transmission contracts generally will not meet the definition of a derivative. Note that transmission-related contracts in an environment where there is a regional transmission organization may have additional considerations and are not addressed in the following discussion. See UP 4 for information on regional transmission organizations and related contracts. Figure 3-23 highlights the derivative evaluation for a typical transmission contract; however, each contract should be evaluated based on its individual facts and circumstances.

Figure 3-23

Does a transmission contract meet the definition of a derivative?

Guidance	Evaluation	Comments
Notional amount and underlying	Met	<ul style="list-style-type: none"> □ Notional (quantity of transmission availability) and underlying (the price of the transport or transmission service) are usually specified.
No initial net investment	Met	<ul style="list-style-type: none"> □ No initial net investment is typically required.
Net settlement	Generally not met	<ul style="list-style-type: none"> □ Transmission contracts are generally physically settled; implicit net settlement is not typical but should be evaluated. □ Currently, there is no market mechanism for net settlement and no active market for spot sales of transmission; however, markets should be monitored.

Transmission contracts are not usually financially settled; however, if this type of contract included terms that required explicit or implicit net settlement, we would expect it to meet the definition of a derivative. In general, transmission contracts do not meet the definition of a derivative because they fail the net settlement criterion. As further discussed in ASC 815-10-15-83(c), there are three possible forms of net settlement: net settlement under the contract terms, net settlement through a market mechanism, and net settlement by delivery of an asset that is readily convertible to cash. Factors to consider in assessing whether transmission contracts meet the net settlement criterion are further discussed in the following paragraphs. See UP 3.2.3 for further information on overall application of the net settlement criterion.

Net settlement under contract terms

When evaluating whether the net settlement criterion is met, a reporting entity should first consider whether the contract explicitly or implicitly provides for net settlement of the entire contract. Forward contracts for transmission typically require physical delivery and do not permit explicit net settlement. However, the type of contract and the terms should be carefully reviewed for any implicit net settlement terms or liquidating damage provisions that may imply that the contract could be net settled.

Net settlement through a market mechanism

In this form of net settlement, one of the parties is required to deliver an asset, but there is an established market mechanism that facilitates net settlement outside the contract. ASC 815-10-15-110 through 15-116 provide indicators to consider in assessing whether an established market mechanism exists. A key aspect of a market mechanism is that one of the parties to the agreement can be fully relieved of its rights and obligations under the contract. We are not aware of any markets in the United States for traditional transmission contracts such that a provider has the ability to be relieved of its full rights and obligations under a previously executed contract.

Net settlement by delivery of an asset that is readily convertible to cash

Whether there is an active spot market for the particular product being sold under the contract is the key factor in assessing whether an asset is readily convertible to cash. Current market conditions should always be considered in this analysis. To be deemed an active market, a market must have transactions with sufficient frequency and volume to provide pricing information on an ongoing basis. In addition, quoted prices from that market will be readily available on an ongoing basis. See UP 3.2.3.3 for further information on the determination of whether a market is active. We are not aware of any active spot markets for transmission in the United States.

Overall conclusion

We are not aware of a market mechanism or active spot market for transmission and thus we believe that derivative accounting is generally not applicable to these contracts. However, a reporting entity should evaluate all facts and circumstances in concluding on the appropriate accounting for transmission contracts, including whether there is a market mechanism or active spot market. In addition, a reporting

entity should monitor its conclusion periodically as markets may evolve, potentially rendering this type of contract a derivative.

Reporting entities may also consider conditionally designating transmission contracts under the normal purchases and normal sales scope exception if physical delivery is probable throughout the life of the contract and the other criteria for application of this exception are met (ASC 815-10-15-22 through 15-51 as applicable). If a conditionally designated normal purchases and normal sales contract meets the definition of a derivative at a later date, it would be accounted for as a normal purchases and normal sales contract from the time the contract becomes a derivative. Absent such a designation, the reporting entity would be required to record the contract at its fair value at the time it becomes a derivative. See UP 3.3.1 for further information on the normal purchases and normal sales scope exception.

Other considerations

Some transmission contracts may contain a lease. For example, a transmission contract for the entire use of a dedicated line with variable pricing as specified in the contract would likely represent a lease of the specified transmission assets. Whether a contract contains a lease should be determined prior to evaluating whether it is a derivative or contains one or more embedded derivatives. See UP 2 for further information on lease accounting considerations.

3.6.7 Water contracts

A forward contract for the physical purchase or sale of water generally will not meet the definition of a derivative instrument because it fails the net settlement criterion. Figure 3-24 highlights the derivative evaluation for a typical water contract; however, each contract should be evaluated based on its individual facts and circumstances.

Figure 3-24

Is a forward physical sale or purchase of water a derivative?

Guidance	Evaluation	Comments
Notional amount and underlying	It depends	<ul style="list-style-type: none"> □ Notional (quantity of water) and underlying (the price of water) may be specified. □ In some cases, production may be dependent on a specific source (plant-specific contract).
No initial net investment	Met	<ul style="list-style-type: none"> □ No initial net investment is typically required.

Guidance	Evaluation	Comments
Net settlement	Generally not met	<ul style="list-style-type: none"> □ Water contracts are generally physically settled; implicit net settlement is not typical but should be evaluated. □ Currently, there is no market mechanism for net settlement and no active markets for spot sales of water; however, markets should be monitored.

In general, a physically settled water contract does not meet the definition of a derivative because it fails the net settlement criterion.

ASC 815-10-15-83(c)

Net settlement. The contract can be settled net by any of the following means:

1. Its terms implicitly or explicitly require or permit net settlement.
2. It can readily be settled net by a means outside the contract.
3. It provides for delivery of an asset that puts the recipient in a position not substantially different from net settlement.

Typically, water-related contracts are not financially settled; however, if a contract with an underlying of water was to be financially settled we would expect it to meet the definition of a derivative. Factors to consider in assessing whether physically settled water contracts meet the net settlement criterion are discussed in the following paragraphs. See UP 3.2.3 for further information on overall application of the net settlement criterion.

Net settlement under contract terms

When evaluating whether the net settlement criterion is met, a reporting entity should first consider whether the contract explicitly or implicitly provides for net settlement of the entire contract. Forward contracts for water typically require physical delivery and do not permit explicit net settlement. However, the contract terms should be carefully reviewed for any terms or liquidating damage provisions that the contract could be net settled.

Net settlement through a market mechanism

In this form of net settlement, one of the parties is required to deliver an asset, but there is an established market mechanism that facilitates net settlement outside the contract. ASC 815-10-15-110 through 15-116 provide indicators to consider in assessing whether an established market mechanism exists. A key aspect of a market mechanism is that one of the parties to the agreement can be fully relieved of its rights and obligations under the contract. We are not aware of any markets in the United

States for water such that a provider has the ability to be relieved of its full rights and obligations under a previously executed contract.

Net settlement by delivery of an asset that is readily convertible to cash

Whether there is an active spot market for the particular product being sold under the contract is the key factor in assessing whether an asset is readily convertible to cash. Current market conditions should always be considered in this analysis. To be deemed an active market, a market must have transactions with sufficient frequency and volume to provide pricing information on an ongoing basis. In addition, quoted prices from that market will be readily available on an ongoing basis (see UP 3.2.3.3 for further information on active markets). We are not aware of any active spot markets for water.

Overall conclusion

We are not aware of a market mechanism or active spot market for water and thus we believe that derivative accounting is generally not applicable to these contracts. However, a reporting entity should evaluate all facts and circumstances in concluding on the appropriate accounting for water contracts, including evaluating whether there is a market mechanism or active spot market. In addition, a reporting entity should monitor its conclusion periodically as markets evolve, potentially rendering this type of contract a derivative. In addition, reporting entities should evaluate this type of contract to determine if there are any embedded derivatives that require separation.

Reporting entities may also consider conditionally designating these contracts under the normal purchases and normal sales scope exception if physical delivery is probable throughout the life of the contract and the other criteria for application of this exception are met (ASC 815-10-15-22 through 15-51 as applicable). If a conditionally designated normal purchases and normal sales contract meets the definition of a derivative at a later date, it would be accounted for as a normal purchases and normal sales contract from the time the contract becomes a derivative. Absent such a designation, the reporting entity would be required to record the contract at its fair value at the time the contract becomes a derivative. See UP 3.3.1 for further information on the normal purchases and normal sales scope exception.

3.6.8 Weather contracts

ASC 815-10-15-59 provides a specific scope exception for non-exchange-traded contracts with an underlying based on a climatic or geological variable, such as a weather-related contract with pricing based on the number of cooling-degree days. Consistent with this exception, derivative accounting is only applicable to weather-related contracts traded on an exchange.

However, ASC 815-45 does provide specific nonderivative guidance on accounting for non-exchange-traded weather derivatives. The guidance includes two different accounting models, depending on the reporting entity's purpose for executing the contracts. The models are summarized in Figure 3-25 and further discussed in ASC 815-45.

Figure 3-25
Weather derivative contract accounting models

Intent	Product	Initial accounting	Subsequent accounting
Nontrading activity	Forward contract	Typically no day one accounting	<input type="checkbox"/> Apply the intrinsic value method
	Purchased option	Recognize an asset measured initially at the amount of premium paid	<input type="checkbox"/> Intrinsic value method should be used at each measurement date <input type="checkbox"/> The option premium should be amortized to expense in a rational and systematic manner ¹
	Written option	Recognize a liability measured initially based on the option premium received	<input type="checkbox"/> Any subsequent changes in fair value should be recognized in earnings <input type="checkbox"/> The option premium should not be amortized
Trading or speculative activity	Forwards and options	All contracts should be accounted for as assets or liabilities at their fair value	<input type="checkbox"/> All subsequent changes in fair value should be recognized in earnings

¹ As discussed in ASC 815-45-30-3A, a purchased or written option may contain an embedded premium or discount if the contract terms are not consistent with current market terms. In those circumstances, the embedded premium or discount should be quantified, removed from the quantified strike price, and accounted for following the guidance for premiums and discounts.

The accounting model applied largely depends on whether a non-exchange-traded weather derivative was executed as part of a reporting entity's trading activities. ASC 815-45-55-1 through 55-6 provide guidance on identifying trading activities relating to weather derivatives, including fundamental and secondary indicators.

ASC 815-45-55-1

Determining whether or when an entity is involved in trading or speculative activities involving weather derivative contracts is a matter of judgment that depends on the relevant facts and circumstances. The framework in which such facts and circumstances are assessed shall be based on an evaluation of the various activities of an entity rather than solely on the terms of the contracts. Inherent in that framework is an evaluation of the entity's intent for entering into a weather derivative contract.

ASC 815-45-20 defines trading as follows:

Partial definition from ASC 815-45-20

Trading: An activity involving securities sold in the near term and held for only a short period of time. The term trading contemplates a holding period generally measured in hours and days rather than months or years.

Overall, a reporting entity is considered to be involved in trading activities related to weather derivatives if it enters into the contracts with an objective of generating short-term profits from the contracts. In accordance with ASC 815-45-55-1, the evaluation of trading versus nontrading should be performed based on the activities of an organization or legal entity. However, if a reporting entity conducts both trading and nontrading activities and those activities are not segregated in such a manner, contracts should be evaluated at inception in accordance with the indicators outlined in ASC 815-45-55-1 through 55-6 to determine if they are trading or nontrading. Only those contracts that are deemed trading should be accounted for at fair value. See UP 3.7 for further information on trading activities.

Recognition and measurement

In general, nontrading weather derivatives are accounted for using the intrinsic value method described in ASC 815-45-35-2. ASC 815-45-55-7 through 55-11 provide application examples, including sample calculations and accounting assuming that the contracts were executed as part of a reporting entity's nontrading operations. In addition, reporting entities should recognize subsequent changes in the fair value of nontrading written option contracts instead of following the intrinsic value method.

Disclosure

In accordance with ASC 815-45-50-1, non-exchange-traded weather derivatives are financial instruments; therefore, these transactions are subject to the disclosure requirements for financial instruments in ASC 825, *Financial Instruments* (ASC 825).

3.7 Trading activities

In some cases, a reporting entity will need to consider whether its derivative-related activities are trading activities. For example, some transactions involving weather derivatives (see UP 3.6.8) and natural gas virtual storage (see UP 5.3) may be considered trading activities. This section provides guidance on what types of activities are considered trading activities.

ASC 815-10-20 provides two useful definitions.

Partial definitions from ASC 815-10-20

Trading: An activity involving securities sold in the near term and held for only a short period of time. The term trading contemplates a holding period generally measured in hours and days rather than months or years.

Trading Purposes: The determination of what constitutes trading purposes is based on the intent of the issuer or holder and shall be consistent with the definition of trading in paragraph 320-10-25-1(a).

ASC 320, *Investments—Debt and Equity Securities* (ASC 320), also addresses trading activities. The definition of trading in ASC 320-10-25-1(a) is consistent with the definition in ASC 815-10-20. The determination of whether a derivative instrument held by a reporting entity is being held for trading purposes is a matter of judgment and will be based on the reporting entity's intent and the specific facts and circumstances. A reporting entity is considered to be involved in trading activities related to commodity derivatives if it enters into the contracts with an objective of generating short-term profits from the contracts.

Reporting entities may also have both trading and nontrading activities. In such cases, an evaluation should be performed to understand the nature and intent of the activities to account for them appropriately. Factors for reporting entities to consider include:

- The purpose—Are the transactions intended to serve customers or to generate additional profits?
- The scope—Are the transactions routine and in accordance with the operating protocols for normal business operations or are they new or structured transactions that require additional approval?
- The timing—Are the instruments longer-term and/or expected to be held over a longer period or are they very short-term and/or expected to be sold within a short period of time?

In addition to the need to consider whether certain transactions are trading for accounting purposes, designation of derivatives as trading instruments will also have an impact on presentation of gains and losses in the income statement. In accordance with ASC 815-10-45-9, realized and unrealized gains and losses on trading derivatives should be presented net in the income statement. Furthermore, unless accounted for in a hedging relationship, a derivative's realized and unrealized gains and losses should not be separately presented in the income statement, irrespective of whether the derivative is classified as trading (see DH 10.2.2 for further information).

Question 3-42

Are there ever circumstances where derivatives not held for trading purposes should be presented net in the income statement?

PwC response

It depends. Reporting entities evaluating the appropriate presentation of nontrading derivatives should consider the guidance provided by ASC 815-10-55-62. In accordance with this guidance, a reporting entity should consider the following factors

in determining whether physically settled derivative instruments not held for trading purposes should be presented on a gross or net basis:

- Economic substance of the transaction
- Guidance related to nonmonetary exchanges
- Gross versus net reporting indicators provided in Subtopic 605-45

The income statement presentation of physically settled derivatives not held for trading purposes will depend on the specific facts and circumstances.

3.8 Presentation and disclosure

The presentation and disclosure requirements for commodity derivative instruments and hedging activities are the same as non-commodity instruments and hedging strategies. These requirements are discussed in detail in FSP 19 and include the following:

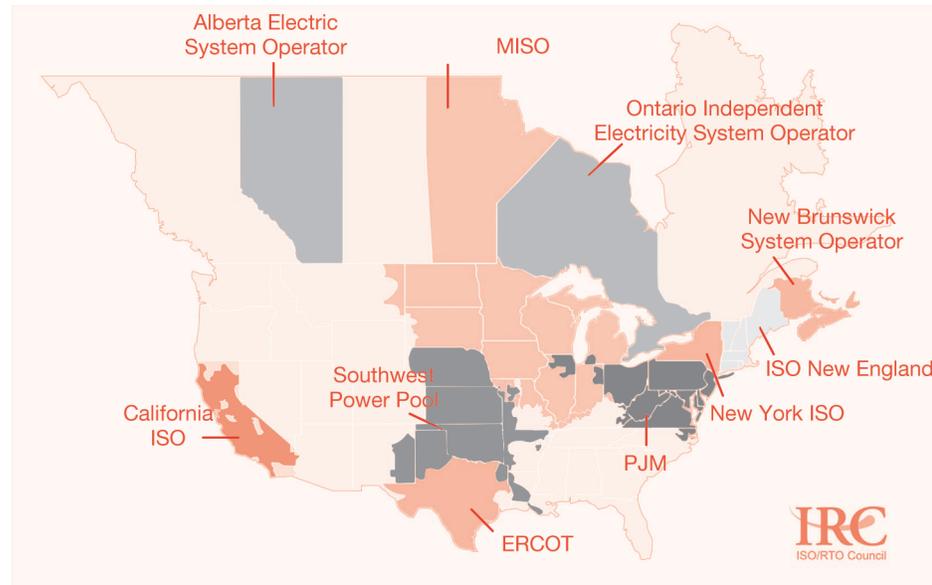
- Presentation of derivative instruments and hedges on the balance sheet, income statement, statement of cash flows, and statement of other comprehensive income
- Qualitative and quantitative disclosures
- Disclosures relating to offsetting and netting of derivative positions
- Disclosures required for bifurcated embedded derivative instruments

Chapter 4:
Regional transmission
organizations

4.1 Chapter overview

The Federal Energy Regulatory Commission (FERC) was established in 1977 through the Department of Energy Organization Act of 1977. The FERC is a U.S. federal agency with jurisdiction over interstate electricity sales, wholesale electricity rates, hydroelectric licensing, natural gas pricing, and oil pipeline rates. In 1996 and 1999, the FERC issued Orders No. 888 and 2000,¹ respectively, which provided the framework to establish the independent entities tasked with overseeing wholesale transmission and energy commerce within the United States. Pursuant to these orders, seven independent system operators (ISOs) and regional transmission organizations (RTOs) were created in the United States. In addition, three similar organizations have been established in Canada. Figure 4-1 provides geographical information regarding ISOs and RTOs in the United States and Canada (herein referred to as regional transmission organizations or RTOs).

Figure 4-1
Map of ISOs and RTOs in the United States and Canada



Source—ISO/RTO Council: Copyright © ISO/RTO Council, all rights reserved.

Regional transmission organizations currently operate markets that ultimately serve about two-thirds of electricity consumers in the United States and more than 50 percent of the population of Canada. In general, RTOs are tasked with maintaining the reliability of the high-voltage electric transmission system and facilitate wholesale power markets in their service territories.

Although RTOs were established in response to various FERC initiatives, FERC purposefully did not insist on one specific approach to their development. This has

¹ FERC Order No. 888, *Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*; FERC Order No. 2000, *Regional Transmission Organizations*.

resulted in varying types of organization and services offered by RTOs across the United States. Although each RTO may have some unique features, these organizations generally ensure nondiscriminatory access to transmission, enable wholesale competition, and perform regional planning to ensure adequate electric resources. The markets administered by these organizations are monitored and assessed by the FERC on an ongoing basis and will continue to evolve in response to market and regulatory influences.

This chapter provides background information on RTOs and addresses certain types of transactions entered into by reporting entities impacted by these organizations. For illustrative purposes, the topics are initially discussed in the context of the market rules of PJM Interconnection, L.L.C. (PJM), a regional transmission organization that manages movement of wholesale electricity in all or parts of 13 mid-Atlantic states and the District of Columbia. PJM is the largest RTO in the United States.

This chapter also highlights considerations for similar instruments in other RTO markets in the United States.

4.2 *Transmission*

The regional RTOs were established primarily to enable short-term and long-term reliability within their respective territories. This is accomplished through certain functions including measuring and monitoring of activity, the balancing of supply and demand, coordination of maintenance, and oversight of the long-term growth strategy of the network. The RTOs themselves do not own or operate any of the transmission assets. Instead they work directly with the transmission owners operating within their jurisdiction. Those entities which are users of the transmission grid or are impacted by its performance include power generation companies and retail distributors as well as investor entities which choose to trade on aspects of the power market.

Transmission owners are required to comply with RTO and FERC regulations when offering transmission services to their customers. Utilities receive regulatory approval for their Open Access Transmission Tariff (OATT), which represents the services available and terms established for all contractual arrangements involving use of the grid. The OATT also sets the pricing for the services provided. The OATT rate is determined based on the expected total cost, both direct and indirect, of moving electricity between generating plants and substations, plus an approved return on equity. Transmission operators are typically regulated public utilities and therefore, accounting for transmission tariffs (billing, collection, cost deferral, etc.) may qualify for application of the guidance in ASC 980. The facts and circumstances of the respective arrangements however, must be considered before applying the standard.

4.3 *PJM capacity market*

PJM's capacity market design is known as the Reliability Pricing Model. RPM is designed to ensure the reliability of the electric grid. Capacity Resources are obtained through an auction process for capacity in PJM. Market participants may also engage in bilateral transactions. PJM requires varying levels of participation in the RPM by market participants as summarized in Figure 4-2:

Figure 4-2
Participation in RPM

Form of participation	Type of entity
Mandatory	Resource providers with (1) available unforced capacity from existing generation resources located in PJM and (2) bilateral contracts for available unit-specific Capacity Resources located in PJM
Generally mandatory	Load Serving Entities (LSEs); however, LSEs can avoid direct participation in RPM auctions by using internally owned Capacity Resources to meet their fixed capacity resource requirement (Fixed Resource Requirement (FRR) alternative)
Voluntary	All other resource providers

Resource providers may alternatively export available capacity outside PJM under certain conditions. The RPM market design and structure as well as related accounting considerations are further discussed in this section. See UP 4.7 for definitions of key terms used throughout this chapter.

4.3.1 RPM auction contracts

The RPM market structure is as follows:

Figure 4-3
RPM auction structure



PJM procures resources through the auction process as follows:

- Base Residual Auction—conducted in May three years prior to the start of the Delivery Year. Load Serving Entities pay for the cost of the commitments obtained through this auction through the Locational Reliability Charge.
- First and Third Incremental Auctions—conducted 23 months and 4 months prior to the start of the Delivery Year, respectively. Market participants obtain additional resources when there is a decrease in the expected capacity committed through the Base Residual Auction (due to cancellation, derating, or other issues).

- Second Incremental Auction—conducted 15 months prior to the start of the Delivery Year. Market participants procure incremental Capacity Resources when capacity needs change due to a change in load forecast.

In addition to scheduled RPM auctions, PJM may conduct a conditional incremental auction if necessary. The auction process allows for the procurement of resource commitments to satisfy the region’s capacity requirements. The cost of those resource commitments is allocated among the LSEs through a Locational Reliability Charge. LSEs may partially or totally offset their Locational Reliability Charge obligations by offering and clearing resources in the base residual auction and second incremental auction, or by designating self-supplied resources.

4.3.1.1 Accounting considerations

In accordance with the commodity contract accounting framework (see UP 1), because property is specified, after identifying the deliverables and the unit of accounting, a reporting entity should first determine whether an RPM auction contract contains a lease. If the contract does not contain a lease, a reporting entity should next assess whether it is a derivative in its entirety. A reporting entity should then consider whether the contract contains any embedded derivatives requiring separation from the host contract (unless the contract is a derivative in its entirety). If neither lease nor derivative accounting apply, the reporting entity would account for the RPM contract as an executory contract (i.e., on an accrual basis).

Lease accounting

A contract for the purchase of capacity that is sourced from a specified power plant could technically qualify as a lease. However, because power plants also produce other outputs, such as power and ancillary services, it is generally not expected that the capacity alone would represent 90 percent of the total value of the plant outputs. As such, this type of contract is generally not expected to meet the definition of a lease (see UP 2 for further information). Therefore, the following discussion focuses on whether an RPM auction contract is a derivative.

Derivative accounting

RPM auction contracts generally will not meet the definition of a derivative instrument. Figure 4-4 highlights the derivative evaluation for a typical RPM auction contract; however, each contract should be evaluated based on its individual facts and circumstances.

Figure 4-4
Does an RPM auction contract meet the definition of a derivative?

Guidance	Evaluation	Comments
Notional amount and underlying	Met	□ Notional (quantity of capacity) and an underlying (auction proceeds) are specified.

Guidance	Evaluation	Comments
No initial net investment	Met	<ul style="list-style-type: none"> □ No initial net investment is required.
Net settlement	Not met	<ul style="list-style-type: none"> □ RPM auction contracts are generally physically settled through delivery of the capacity; implicit net settlement is not typical but should be evaluated. □ Currently, there is no market mechanism for net settlement and no active markets for spot sales of RPM capacity; however, markets should be monitored.

In general, we would not expect an RPM auction contract to be accounted for as a derivative because it fails the net settlement criterion.

ASC 815-10-15-83(c)

Net settlement. The contract can be settled net by any of the following means:

1. Its terms implicitly or explicitly require or permit net settlement.
2. It can readily be settled net by a means outside the contract.
3. It provides for delivery of an asset that puts the recipient in a position not substantially different from net settlement.

The following discussion provides information on factors to consider in assessing whether an RPM auction contract has the characteristic of net settlement. See UP 3.2.3 for further information on the overall application of the net settlement criterion.

Net settlement under contract terms

When evaluating whether the net settlement criterion is met, a reporting entity should first consider whether the contract explicitly or implicitly provides for net settlement of the entire contract. RPM auction contracts require the generator to deliver capacity during the Delivery Year equal to the notional amount of capacity that the generator won in the auction. This requirement is for each day of the Delivery Year; and if the capacity is not provided, the generator may incur significant fines and penalties. There are no provisions permitting or requiring net settlement in the contract, either explicitly or implicitly.

Net settlement through a market mechanism

In this form of net settlement, one of the parties is required to deliver an asset, but there would need to be an established market mechanism that facilitates net settlement outside the contract. ASC 815-10-15-110 through 15-116 provides guidance on indicators to consider in assessing whether an established market mechanism

exists. A key aspect of a market mechanism is that one of the parties to the agreement can be fully relieved of its rights and obligations under the contract.

In the case of RPM, resource providers that bid into the initial base residual auction have an opportunity to be relieved of their obligations through the first and third incremental auctions. However, this opportunity exists only if there is a physical issue associated with the plant (e.g., it is not available or it is derated) and the auctions occur only twice in a three-year period. Moreover, the incremental auctions do not have the level of activity found in the initial auction because only residual resources are available to participate.

Due to the market design, the incremental auctions are not intended to and do not provide the resource provider with the ability to be relieved of its full rights and obligations under a previously executed contract. Therefore, the auction structure does not create a market mechanism as defined in ASC 815. In addition, the RPM market includes bilateral transactions that are facilitated by PJM through an electronic board (eRPM). As discussed in UP 4.3.2, the eRPM bulletin board currently does not meet the criteria to qualify as a market mechanism.

Net settlement by delivery of an asset that is readily convertible to cash

Whether there is an active spot market for the particular product being sold under the contract is the key factor in assessing whether an asset is readily convertible to cash. Current market conditions should always be considered in this analysis. To be deemed an active spot market, a market must have transactions with sufficient frequency and volume to provide pricing information on an ongoing basis. In addition, quoted prices from that market must be readily available on an ongoing basis. See UP 3.2.3.3 for further information on the determination of whether a market is active.

In the case of the RPM market, we understand that there may be some bilateral spot market activity, with trading among market participants to meet daily obligations. However, there are no quoted prices in the market or transparency into the level of activity, frequency, and volume of transactions. These are indicators that there is not an active spot market for capacity in PJM.

Overall conclusion

We are not aware of a market mechanism or active spot market for RPM capacity contracts and thus we believe that derivative accounting is generally not applicable to these contracts. Instead, the contracts should be accounted for as executory contracts or a legal obligation to the PJM market. However, a reporting entity should evaluate all facts and circumstances in concluding on the appropriate accounting for an RPM contract. In addition, a reporting entity should monitor its conclusion periodically because markets may evolve, potentially rendering this type of contract a derivative. Finally, a reporting entity should evaluate the contract to determine if there are any embedded derivatives that require separation.

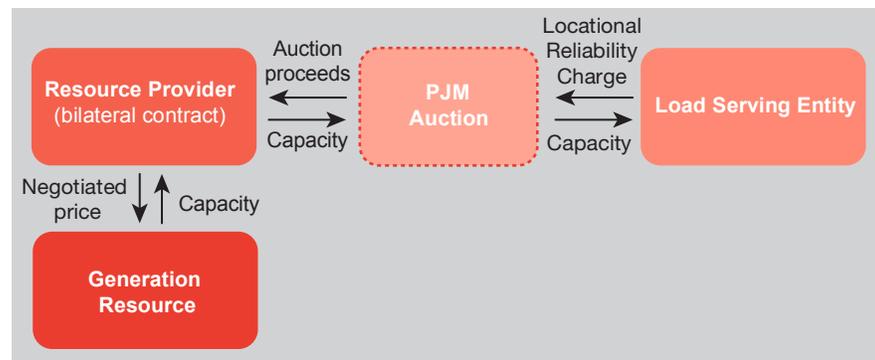
Reporting entities may also consider conditionally designating RPM contracts under the normal purchases and normal sales scope exception if physical delivery is probable throughout the life of the contract and the other criteria for application of

this exception are met (ASC 815-10-15-22 through 15-51 as applicable). If a conditionally designated normal purchases and normal sales contract meets the definition of a derivative at a later date, the contract would be accounted for as a normal purchases and normal sales contract from the time it becomes a derivative. Absent such a designation, the reporting entity would be required to record the contract at its fair value at the time it becomes a derivative. See UP 3.3.1 for further information on the normal purchases and normal sales scope exception.

4.3.2 Bilateral capacity contracts

The basic transaction structure for bilateral capacity contracts in PJM is as follows:

Figure 4-5
RPM unit-specific bilateral capacity transaction structure



PJM’s bilateral capacity market provides Load Serving Entities with the opportunity to hedge the Locational Reliability Charge. This market also allows resource providers to transact for any auction commitment shortfalls by using unit-specific contracts. The purpose of a unit-specific bilateral contract is to transfer the rights to or control of a specified amount of capacity from the seller to the buyer. Bilateral contracts for unit-specific resources can be offered in the RPM if PJM’s specifications are met.

Unit-specific capacity transactions are posted through PJM’s eRPM, which allows participants to post and view requests to buy and sell capacity. This electronic bulletin board is intended to facilitate bilateral activity. Both parties to a transaction must confirm the transaction in eRPM prior to the start date of the transaction. These transactions may occur before or after the PJM auctions. If the transaction occurs before the auction, capacity obtained through a unit-specific contract may be offered in the auction and the buyer of the capacity will transact with PJM. If the activity occurs after the auction, the PJM auction credit and related resource requirement is transferred from the seller to the buyer.

4.3.2.1 Accounting considerations

The determination of the appropriate accounting for unit-specific bilateral capacity contracts follows an approach similar to the discussion of RPM auction contracts in UP 4.3.1. Consistent with the conclusions reached for RPM auction contracts, generally, we would not expect a unit-specific bilateral capacity contract to meet the

definition of a lease. Therefore, this discussion focuses on whether this type of contract meets the definition of a derivative.

Derivative accounting

Unit-specific bilateral capacity contracts generally will not meet the definition of a derivative instrument. Figure 4-6 highlights the derivative evaluation for a typical unit-specific bilateral capacity contract; however, each contract should be evaluated based on its individual facts and circumstances.

Figure 4-6

Does a unit-specific bilateral capacity contract meet the definition of a derivative?

Guidance	Evaluation	Comments
Notional amount and underlying	Met	<ul style="list-style-type: none"> □ Notional (quantity of capacity) and underlying (the price of the capacity) are usually specified.
No initial net investment	Met	<ul style="list-style-type: none"> □ No initial net investment is typically required.
Net settlement	Generally not met	<ul style="list-style-type: none"> □ Unit-specific bilateral capacity contracts are generally physically settled; implicit net settlement is not typical but should be evaluated. □ Currently there is no market mechanism for net settlement and no active markets for spot sales of PJM capacity; however, markets should be monitored.

In evaluating unit-specific bilateral capacity contracts, the key question is whether the contract has the characteristic of net settlement.

ASC 815-10-15-83(c)

Net settlement. The contract can be settled net by any of the following means:

1. Its terms implicitly or explicitly require or permit net settlement.
2. It can readily be settled net by a means outside the contract.
3. It provides for delivery of an asset that puts the recipient in a position not substantially different from net settlement.

Factors to consider in making the net settlement assessment in the context of unit-specific bilateral capacity contracts are discussed in the following paragraphs. See UP 3.2.3 for further information on overall application of the net settlement criterion.

Net settlement under contract terms

When evaluating whether the net settlement criterion is met, a reporting entity should first consider whether the contract explicitly or implicitly provides for net settlement of the entire contract. With respect to unit-specific bilateral capacity contracts, the selling party is required to deliver capacity to the buyer as registered in the eRPM system. Once the contract is executed, the capacity is recognized within the PJM market as the buyer's capacity. Therefore, the seller is required to deliver capacity to the buyer and we would not expect any provisions for net settlement in this type of contract. However, the reporting entity should review the contract terms to ensure that there are no implicit net settlement terms or liquidating damage provisions that may imply the contract could be net settled.

Net settlement through a market mechanism

In this form of net settlement, one of the parties is required to deliver an asset, but there would need to be an established market mechanism that facilitates net settlement outside the contract. ASC 815-10-15-110 through 15-116 provides guidance on indicators to consider in assessing whether an established market mechanism exists. A key aspect of a market mechanism is that one of the parties to the agreement can be fully relieved of its rights and obligations under the contract.

There are two potential market mechanisms for unit-specific bilateral capacity contracts: (1) the PJM auction process (see evaluation in UP 4.3.1) and (2) the electronic bulletin board structure used to transact unit-specific bilateral contracts. The eRPM structure results in the transfer of all rights and obligations under the contract. Therefore, we specifically evaluated the eRPM structure based on the market mechanism framework. In accordance with ASC 815-10-15-111, the term market mechanism may be interpreted broadly but must have all of the characteristics discussed below (excerpts from ASC 815-10-15-111 are highlighted in italics):

- *ASC 815-10-15-111(a)—It is a means to settle a contract that enables one party to readily liquidate its net position under the contract.*

The eRPM market structure does not provide the means to net settle a contract. It may enable transactions between individual buyers and sellers; however, the seller under the contract is required to deliver capacity to the buyer and would not be able to net settle a bilateral or auction contract. In addition, there are not multiple counterparties standing by and willing to take on this type of contract. As such, it is not possible for either party to the contract to readily liquidate its net position under the contract.

- *ASC 815-10-15-111(b)—It results in one party to the contract becoming fully relieved of its rights and obligations under the contract.*

This condition is met. If parties execute a unit-specific bilateral capacity contract involving "cleared capacity," the seller's obligation to deliver to PJM under its RPM auction contract is transferred to the buyer.

- *ASC 815-10-15-111(c)—Liquidation of the net position does not require significant transaction costs.*

Whether this condition is met will depend on the specific facts and circumstances related to the bilateral transactions. Due to the lack of market transparency, reporting entities would need to perform due diligence to determine the level of transaction costs and whether those are customary for bilateral activity.

- *ASC 815-10-15-111(d)—Liquidation of the net position under the contract occurs without significant negotiation and due diligence and occurs within a time frame that is customary for settlement of the type of contract.*

Factors that would indicate this criterion is met are discussed in ASC 815-10-15-116 and include: (a) binding prices for the instrument are readily available; (b) transfers of the instrument involve standardized documentation (rather than contracts with entity-specific specifications) and standardized settlement procedures; (c) individual contract sales do not require significant negotiation and unique structuring; and (d) the closing period is not extensive since there is not a need to permit legal consultation and document review.

Reporting entities should assess whether this criterion is met based on current activity in eRPM. However, a lack of transparency in the eRPM market would suggest that a reporting entity's ability to determine whether this criterion is met is restricted.

The key factor in this evaluation is that there are no quoted market prices and no buyers standing ready to transact via eRPM. We understand there is some level of activity in this market; however, it does not appear that there is sufficient liquidity to support the conclusion that a market mechanism exists.

Net settlement by delivery of an asset that is readily convertible to cash

Whether there is an active spot market for the particular product being sold under the contract is the key factor in assessing whether an asset is readily convertible to cash. Current market conditions should always be considered in this analysis. To be deemed an active market, a market must have transactions with sufficient frequency and volume to provide pricing information on an ongoing basis. In addition, quoted prices from that market must be readily available on an ongoing basis. See UP 3.2.3.3 for further information on the determination of whether a market is active.

Consistent with the discussion of RPM auction contracts (see UP 4.3.1), we understand that there is some bilateral spot market activity as market participants trade to meet daily obligations. However, there are no quoted prices in the market or transparency into the level of activity, frequency, and volume of transactions.

Overall conclusion

We are not aware of a market mechanism or active spot market for RPM unit-specific bilateral contracts, and thus we believe that derivative accounting is generally not applicable to these contracts. Instead, the contracts should be accounted for as executory contracts or a legal obligation. However, a reporting entity should evaluate

all facts and circumstances in concluding on the appropriate accounting for RPM unit-specific bilateral contracts. In addition, a reporting entity should monitor its conclusion periodically because markets may evolve, potentially rendering this type of contract a derivative. Finally, a reporting entity should evaluate the contract to determine if there are any embedded derivatives that require separation.

Reporting entities may also consider conditionally designating RPM unit-specific bilateral contracts under the normal purchases and normal sales scope exception if physical delivery is probable throughout the life of the contract and the other criteria for application of this exception are met (ASC 815-10-15-22 through 15-51 as applicable). If a conditionally designated normal purchases and normal sales contract meets the definition of a derivative at a later date, the contract would be accounted for as a normal purchases and normal sales contract from the time it becomes a derivative. Absent such a designation, the reporting entity would be required to record the contract at its fair value at the time it becomes a derivative. See UP 3.3.1 for further information on the normal purchases and normal sales scope exception.

4.4 *PJM congestion instruments*

Within PJM, congestion creates direct costs to market participants related to transmission congestion charges as well as indirect costs as a result of differences in locational prices when generators are dispatched out of merit order (i.e., in a different sequence than the original schedule) to relieve congestion. Auction Revenue Rights and Financial Transmission Rights are financial instruments used in PJM that provide holders with the opportunity to offset congestion costs. ARRs and FTRs entitle or require the holder to receive payment or pay charges based on price differences at the applicable trading locations.

This section provides an overview of the ARR and FTR process and addresses related accounting issues, including whether the instruments meet the definition of a derivative. UP 4.7 includes the definitions of key terms used throughout this chapter.

4.4.1 *Overview of the ARR and FTR process*

ARRs and FTRs are financial instruments designed to provide a financial hedge against transmission congestion charges.

□ *Auction Revenue Rights*

ARRs are allocated annually to Firm Transmission Service Customers and entitle holders to the proceeds, or require them to pay the charges, related to the sale of FTRs in an annual FTR Auction (based on price differences between the point of receipt (Source) and the point of delivery (Sink) nodes. The economic value of an ARR can be positive (a benefit) or negative (a liability). ARR holders also have an option to “self-schedule” and convert the ARRs to FTRs (see discussion under *Allocation of ARRs* below).

- *FTR obligations*

FTRs are financial instruments that entitle the holder to receive compensation for transmission congestion charges that arise when the transmission grid is congested in the day-ahead market. Each FTR obligation is defined from the Source to the Sink. FTR obligations entitle the holder to receive or require the holder to make payments based on locational price differences experienced in the Day-Ahead Energy Market. FTRs essentially entitle the holder to rebates of congestion charges paid by the Firm Transmission Service Customers.

- *FTR options*

FTR options are similar to FTR obligations; however, no payment is required from the FTR option holder if the value is negative.

The ARR and FTR process in PJM has the following general timeline:

Allocation of ARRs

The annual ARR allocation is a two-stage process that typically begins in mid-March and concludes in early April. During the first stage of the process, Firm Transmission Service customers may request ARRs along transmission paths for all or any portion of an existing generation resource, up to their individual total network load in a particular Zone. During the Planning Period (June 1 to May 31), ARRs are automatically reallocated on a daily basis based on changes in zonal peak load.

ARR holders have an option to convert the product to an FTR with the same Source and Sink points as the ARR through a process called “self-scheduling” in the first round of the annual FTR Auction. In effect, an ARR provides the holder with a fixed amount of revenue (based on the results of the FTR Auction) compared with an FTR, which provides ongoing offset against transmission congestion charges.

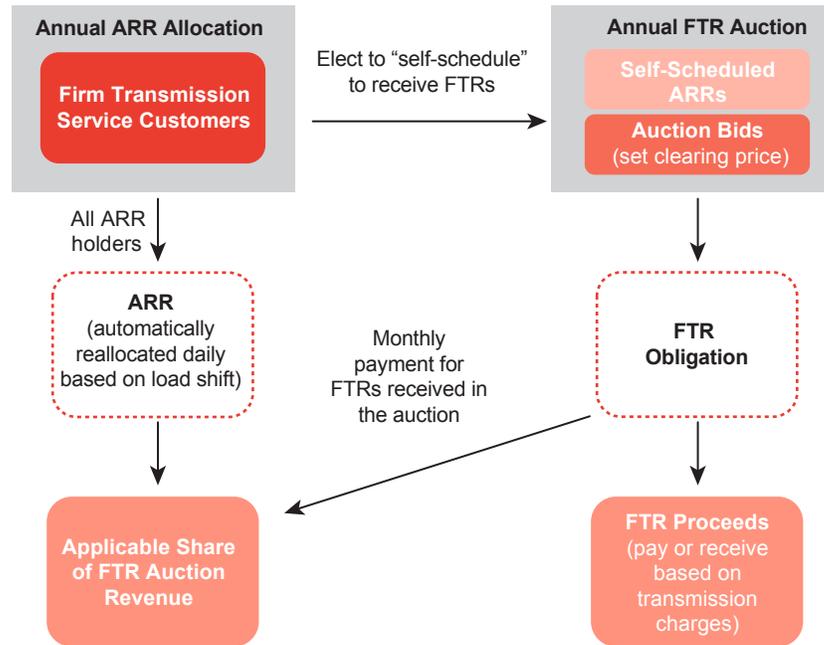
FTR Auction

After the conclusion of the ARR allocation process, PJM conducts a four-round annual FTR Auction, which typically occurs from mid-April to early May of the PJM Planning Period. The FTR Auction conducted by PJM generates revenues by selling FTRs to the highest bidders. Self-scheduled ARRs are included in the FTR Auction and require ARR holders to pay the auction price. Proceeds generated from the annual FTR Auctions are provided to the holders of the ARRs. Additionally, FTRs can be acquired through monthly or long-term FTR Auctions or secondary market trades.

ARRs and FTRs—process

The annual ARR process and cash flows are summarized in Figure 4-7.

Figure 4-7
ARR and FTR process



Incremental ARR, residual ARR, and the monthly and long-term FTR Auctions are not included in the flowchart above. In addition, there are no self-scheduled ARRs in the monthly or long-term FTR Auctions. Monthly and long-term FTR Auctions include residual FTRs not sold through the annual process. In addition, FTR options are not included in the flowchart. FTR options provide only for payment to the holder based on transmission charges.

In summary, ARR and FTR financial instruments are both designed to provide a hedge against transmission congestion charges. Revenues received by PJM in the FTR Auction process are allocated to the holders of ARRs. Similarly, PJM collects transmission congestion costs from market participants delivering power and paying congestion cost and allocates these proceeds to the holders of the FTRs. In theory, an ARR holder that self-schedules to an FTR (i.e., converts its ARR into an FTR) and uses the underlying transmission to serve customers, should be net income neutral, as it would receive and pay the following cash flows:

- From the ARR—it will receive FTR Auction proceeds
- From the FTR—it will pay FTR Auction charges and receive transmission congestion charges
- As a transmission user—it will pay transmission charges

As a result of these transactions, a transmission customer (i.e., an ARR holder) has the opportunity to obtain FTRs at no net cost along those paths needed to serve its customers. As a user of the transmission, an FTR holder may be required to make congestion payments; however, these payments should be offset by the benefit of holding the FTR. As such, in theory, a Load Serving Entity should not have any net cash inflow/outflow associated with congestion charges required to serve load (although there may be some differences due to shortfalls in amounts received).

The accounting for ARR and FTRs is discussed in the following section.

4.4.2 **Accounting for ARRs**

ARRs are allocated to transmission service customers based on their load commitments and underlying firm transmission agreements. As further discussed below, an allocated ARR initially qualifies as a derivative; however, the FTR Auction results in the settlement of the derivative, at which time it is accounted for as a receivable. For calendar year-end companies, the allocation and auction process is completed within the second quarter of the year (i.e., the ARR is a receivable balance at the end of the second quarter). The accounting prior to and subsequent to the FTR Auction is discussed in the following sections.

4.4.2.1 **Initial accounting for the ARR**

In determining the initial accounting for ARRs, a reporting entity should first consider the accounting for the ARR itself and then consider the accounting for the receipt of the ARR proceeds. As summarized in Figure 4-8, during the period after the ARR allocation and before the FTR Auction, we believe that an ARR generally meets the definition of a derivative.

Figure 4-8

Does an ARR meet the definition of a derivative?

Guidance	Evaluation	Comments
Notional amount and underlying	Generally met	<ul style="list-style-type: none"> □ Notional (quantity of megawatts) and underlying (settlement is based on locational price differences between the Source and the Sink) are specified. □ If load shifts are significant, the reporting entity may initially conclude that a notional amount cannot be determined.
No initial net investment	Met	<ul style="list-style-type: none"> □ No initial net investment is required.
Net settlement	Met	<ul style="list-style-type: none"> □ Contractual ARRs are settled in cash; therefore, ARRs meet the net settlement criterion in ASC 815-10-15-83(c)(1).

The ARR specifies a notional amount (a specific megawatt amount) and is settled based on locational price differences. The ARR settlement amount is determined based on the auction price and the notional amount of the ARR. The settlement proceeds are received in cash. Therefore, we generally conclude that the ARR meets the definition of a derivative. See further discussion in the responses to the following questions.

Question 4-1

Is there an acceptable alternative view that an ARR is not a derivative?

PwC response

Some believe that ARRs do not meet the definition of a derivative based on the conclusion that an ARR does not have an underlying. The price of an ARR is determined through the auction process, with market participants determining the value by bidding on various paths. As such, the settlement amount is not based on the interaction between the underlying and the notional. Thus, supporters of this view believe that this criterion is not met. Instead, they believe ARRs represent a receivable at the point of initial allocation.

We believe that ARRs should be accounted for as derivatives. However, from a practical perspective, the ARRs are allocated in May and the annual FTR Auctions are completed (and the ARR value is established) before the end of June. As a result, by the end of the second quarter (for calendar year-end companies), the ARR value is fixed and the ARR asset represents a receivable for the proceeds to be received on a monthly basis from the annual FTR Auction. Therefore, for most reporting entities, the question of whether an ARR is a derivative is applicable only for internal reporting purposes. By June 30 of each year, the value of an ARR is established and should be accounted for as a receivable. See UP 4.4.2.2 for discussion of the subsequent accounting.

Question 4-2

Does an ARR qualify for the scope exception available for certain contracts that are not traded on an exchange?

PwC response

No. ASC 815-10-15-59 provides guidance on certain contracts that are not traded on an exchange as follows:

Excerpt from ASC 815-10-15-59

Contracts that are not exchange-traded are not subject to the requirements of this Subtopic if the underlying on which the settlement is based is any one of the following: . . . (b) The price or value of a nonfinancial asset of one of the parties to the contract provided that the asset is not readily convertible to cash. This scope exception applies only if both of the following are true:

1. The nonfinancial assets are unique.
2. The nonfinancial asset related to the underlying is owned by the party that would not benefit under the contract from an increase in the price or value of the nonfinancial asset.

In accordance with this exception, a contract is not a derivative if it is based on the fair value of a nonfinancial asset of one of the parties to the contract. In certain cases, the ARR holder may have contractual transmission service on a line where it receives ARRs. The value of the ARR is based on the difference in price between the Source and the Sink as determined in the FTR Auction. Therefore, a question arises as to whether the settlement of the ARR is based on the value of a nonfinancial asset of one of the parties to the contract (i.e., the value of the underlying transmission).

However, the transmission revenue (to be received by the transmission holder) and the congestion revenue (to be received by the holder of the FTR) represent two separate payment streams. The value of the transmission contract is the tariff value of the transmission and does not incorporate the separate congestion cash flows. The ARR holder is generally the Load Serving Entity and will receive proceeds from the ARR that are based on the expected value of congestion costs (bid amounts for the FTRs).

As such, we do not believe that the value of the ARR is linked to the value of transmission contracts or underlying transmission owned by the ARR holder. Therefore, the scope exception is not applicable.

Question 4-3

Do ARR reallocations (load shift) change the conclusion that an ARR is a derivative?

PwC response

It depends. ARR holders are entitled to self-schedule FTRs equal to the allocated quantity of ARRs in the first round of the annual FTR auction. The notional amount for this right is fixed in the initially allocated ARR. However, the notional amount of the ARR may subsequently change prior to receipt of the cash as a result of load shifts.

ASC 815-10-55-5 through 55-7 provides relevant guidance in addressing notional amounts that may change over the life of a contract in the context of requirements contracts. Although ARRs are not requirements contracts, the overall guidance is helpful in evaluating the impact of potential notional changes.

Excerpt from ASC 815-10-55-7(a)

The determination of a requirements contract's notional amount must be performed over the life of the contract and could result in the fluctuation of the notional amount if, for instance, the default provisions reference a rolling cumulative average of historical usage. If the notional amount is not determinable, making the quantification of such an amount highly subjective and relatively unreliable . . . such contracts are considered not to contain a notional amount as that term is used in this Subtopic.

In accordance with this guidance, a potential future change in notional amount does not impact the conclusion that the contract has a notional. However, there would be no notional if the determination of the amount is highly subjective and unreliable.

In evaluating an ARR, the notional amount of the contract may change any time from the point it is initially allocated until the reporting entity receives the final cash proceeds. If load shift is minimal, the determination of the notional amount is reliable and, as a result, the contract has a notional. However, if the load shift is significant, the initial determination of the quantity would be unreliable and there would be no notional amount. Reporting entities should evaluate this consideration and make a determination based on their historical experience and future load expectations.

Question 4-4

Does determination of the ARR value based on the results of the auction change the conclusion that the ARR has an underlying and a notional amount?

PwC response

No. The ultimate value of the ARR is determined based on the difference between the locational marginal price at the ARR Sink and the ARR Source as determined in each round of the annual FTR Auction. Although the value is developed through an auction rather than through another mechanism, we believe this represents an interaction between an underlying and a notional amount.

The ARR settlement amount is determined based on the interaction between the prices (as determined through the auction) and the notional amount of the ARR. The incorporation of the auction results does not change the fact that the amount of the payout is determined by the terms of the contract and the interaction of the underlying and notional amount. Therefore, the auction does not impact the conclusion that the contract has an underlying and a notional amount.

Question 4-5

Is an ARR a derivative even though the settlement proceeds may change?

PwC response

Yes. There may be some adjustments to and differences in the actual proceeds due to the PJM allocation process. This may cause some to question whether the settlement truly reflects the interaction between an underlying and a notional amount. However, these adjustments are expected to primarily relate to credit or other shortfalls that occur in the payment process. Any contract may not be fully paid due to issues in settlement. Therefore, the potential settlement adjustments do not impact the conclusion that the contract has an underlying and notional amount.

Question 4-6

Is an ARR a derivative even though the FTR Auction proceeds are received over a 12-month period, instead of immediately?

PwC response

Yes. The value of an ARR is determined through the annual FTR auctions and the proceeds are distributed to the ARR holders over the Planning Period (the following 12 months). Whether this constitutes net settlement in accordance with ASC 815-10-15-83(c)(1) should be determined by reference to the guidance in ASC 815-10-15-104 through 15-106, which address settlement through a structured payment.

Excerpt from ASC 815-10-15-104

A contract that provides for such a structured payout of the gain (or loss) resulting from that contract meets the characteristic of net settlement in paragraphs 815-10-15-100 through 15-109 if the fair value of the cash flows to be received (or paid) by the holder under the structured payout are approximately equal to the amount that would have been received (or paid) if the contract had provided for an immediate payout related to settlement of the gain (or loss) under the contract.

In this case, the payments are received over 12 months and there is no interest component. Therefore, the holder of the ARR does not receive the benefit of reinvestment of the proceeds. However, the bidder is also paying for the FTR over a 12-month period; therefore, the bid price presumably incorporates a time-value element.

Furthermore, given the relatively short duration of the payout (less than one year), we conclude that any time value of money would have an inconsequential impact on the fair value of the cash flows to be received over the duration of the payout as compared with those that would be received upon immediate payment. As such, the contract meets the net settlement criterion.

4.4.2.2 *Accounting for ARRs subsequent to the FTR Auction*

Subsequent to the FTR Auction, an ARR holder has a receivable for its share of the auction proceeds. In assessing the accounting for the ARR, reporting entities should consider the appropriate timing and amount of revenue to be recognized. As noted above, PJM imposes a restriction on the receipt of the ARR revenues, requiring that ARRs be reallocated over the following year on a daily basis based on actual customer load. A reporting entity should consider this obligation to serve future load, a requirement that is substantive and outside of its control. In addition, a reporting entity may have other regulatory requirements associated with its activities. In light of these obligations, reporting entities generally recognize revenue contemporaneously with receipt of the ARR-related cash flows (i.e., when the reporting entity serves the underlying load).

Prior to the recognition of revenue, reporting entities often record no amounts related to the ARR, because the performance obligation would offset any asset recorded. PJM requires explicit net settlement provisions for all transactions between it and its customers. PJM's operating protocols² require set-off of ongoing billing amounts as

² This requirement is pursuant to the Amended and Restated Operating Agreement of PJM Interconnection, L.L.C., effective July 5, 2012.

well as amounts owed in the event of default by one of the members. In addition, in accordance with these protocols, PJM has the right of offset for any amounts due to or from a member, arising from any agreement or arrangement. All PJM-related amounts are reported on and settled through combined periodic invoices. PJM requires setoff of all amounts due to and from it, all amounts are billed on one invoice, and only one net payment is made. Therefore, the asset and any related liability would be eligible for net reporting in accordance with the guidance provided by ASC 210, *Balance Sheet* (ASC 210), in ASC 210-20-45-1.

4.4.3 Accounting for FTRs

Reporting entities may purchase FTRs through the long-term, annual, or monthly FTR Auctions, as well as through bilateral transactions with other market participants. FTR bilateral transactions may be made through eFTR or directly with other market participants. Transactions completed through eFTR result in a transfer of ownership and are reflected in subsequent PJM invoices. Independent trades are not tracked by PJM and are settled apart from the PJM invoice.

4.4.3.1 Initial accounting for FTRs

An FTR obligation is a financial instrument that results in payment or receipt of funds based on the difference in the day-ahead locational marginal price (LMP) between the Source and the Sink. Similarly, an FTR option is based on differences in the day-ahead LMP; however, the FTR option holder will not be obligated to make a payment if the value is negative. FTR obligations and FTR options are referred to collectively in this section as “FTRs.”

Due to the nature of an FTR, a question arises as to whether it meets the definition of a derivative. As summarized in Figure 4-9, FTRs meet the definition of a derivative as set out in ASC 815-10-15-83.

Figure 4-9
Does an FTR meet the definition of a derivative?

Guidance	Evaluation	Comments
Notional amount and underlying	Met	Notional (quantity of megawatts) and underlying (the difference between the price at the Source and the Sink) are specified.
No initial net investment	Met	No initial net investment is required.
Net settlement	Met	FTRs are settled in cash; therefore, FTRs meet the criterion in ASC 815-10-15-83(c)(1). The FTR contract does not require the delivery of electricity across the path that is designated in the FTR.

An FTR has an underlying and a notional amount specified in the contract. These amounts are not subject to change in the future (i.e., load shift does not impact FTRs). Furthermore, FTRs require no initial net investment and require settlement in cash. As such, FTRs are financial derivatives in accordance with ASC 815.

Question 4-7

Does the auction payment required to acquire the FTR represent an initial net investment in the contract?

PwC response

No. A reporting entity may pay a significant dollar amount for an FTR at the annual, monthly, or long-term auctions, or through bilateral trading. However, these payments represent settlement of the fair value of the contract on the transaction date (not the expected payout when the FTR is later settled). Fair value payments do not represent a significant initial net investment in the contract.

Question 4-8

How should a reporting entity record the initial purchase of FTRs?

PwC response

A reporting entity may bid for an FTR or obtain an FTR by “self-scheduling” an ARR in the FTR auction. In either case, the reporting entity has a payable to PJM and a derivative with an initial carrying amount equal to the auction price. Therefore, upon purchase, the reporting entity should record the following journal entries with respect to its FTRs (whether self-scheduled or obtained through bid in the auction process):

DR FTR asset	xx
CR PJM FTR payable	xx

The payable would be reversed once it is settled with PJM. Similarly, an FTR obtained through a bilateral transaction would result in an FTR asset and a payable to the counterparty. Subsequent changes in the fair value of the FTR would be recognized as gains or losses in the income statement.

Question 4-9

Are there any specific accounting considerations for self-scheduled FTRs?

PwC response

No. The accounting for a self-scheduled FTR is consistent with the overall model for FTRs described above. The reporting entity has no continuing obligation related to the FTR itself once the FTR is obtained. The FTR will not be adjusted for load shift and a reporting entity can sell the FTR with no future obligation to PJM. Thus, the

accounting for self-scheduled FTRs is consistent with FTRs obtained through the auction. The reporting entity should record an FTR asset and related FTR payable after the FTR auction, and subsequent gains and losses related to such FTRs should be recognized in the income statement. In addition, the reporting entity should continue to follow the accounting for the related ARR as discussed in UP 4.4.2.

4.5 *PJM ancillary services market*

Ancillary services are used within an RTO to support the transmission of energy from generation sources to areas of load and to maintain reliable operation of the energy grid. Ancillary services in PJM include:

- Regulation market—regulation service adjusts for short-term changes in electricity usage that might impact the stability of the power system. Resource owners submit specific offers and PJM utilizes these offers together with energy offers and resource schedules to optimize the dispatch profile and forecast hourly clearing prices. These clearing prices are then utilized to compute the credits allocated to providers and charges allotted to purchasers of the regulation service.
- Synchronized reserve market—the synchronized reserve market supplies or removes electricity from the grid if it experiences an imbalance between customer load and generation supply. Resource owners submit resource-specific offers to provide synchronized reserve. PJM utilizes these offers together with energy offers and resource schedules to optimize the RTO dispatch profile and forecast prices.

In addition to the two markets described above, Black Start Service enables transmission providers and owners to designate certain generators as “Black Start Units,” which are used to restore power to the transmission system following a system-wide blackout. An agreement for ancillary services should be evaluated to determine if it qualifies as a derivative under ASC 815. In general, ancillary services contracts in PJM do not meet the definition of a derivative because they fail the net settlement criterion. Figure 4-10 highlights the derivative evaluation for a typical ancillary services contract; however, each contract should be evaluated based on its individual facts and circumstances.

Figure 4-10

Does a PJM ancillary services agreement meet the definition of a derivative?

Guidance	Evaluation	Comments
Notional amount and underlying	Met	□ Notional (quantity of the ancillary service) and underlying (the price) are usually specified.
No initial net investment	Met	□ No initial net investment is typically required.

Guidance	Evaluation	Comments
Net settlement	Generally not met	<ul style="list-style-type: none"> □ Ancillary service contracts are generally physically settled; implicit net settlement is not typical but should be evaluated. □ Currently, there is no market mechanism for net settlement and no active market for spot sales of ancillary services; however, markets should be monitored.

In general, we would not expect a contract for PJM ancillary services to be accounted for as a derivative because it fails the net settlement criterion.

ASC 815-10-15-83(c)

Net settlement. The contract can be settled net by any of the following means:

1. Its terms implicitly or explicitly require or permit net settlement.
2. It can readily be settled net by a means outside the contract.
3. It provides for delivery of an asset that puts the recipient in a position not substantially different from net settlement.

Factors to consider in assessing whether PJM ancillary services contracts meet the net settlement criterion are further discussed in the following paragraphs. See UP 3.2.3 for further information on overall application of the net settlement criterion.

Net settlement under contract terms

When evaluating whether the net settlement criterion is met, a reporting entity should first consider whether the contract explicitly or implicitly provides for net settlement of the entire contract. Contracts for ancillary services typically require physical delivery (i.e., a notional amount of power to provide for system stability) and do not permit explicit net settlement. In PJM, bilateral contracts for regulation and synchronized reserve service typically require physical transfer and may not be changed once reported and confirmed. If changes are necessary, the original bilateral contracts would need to be deleted and a new contract created. However, the type of contract and its terms should be carefully reviewed to determine that there are no implicit net settlement terms or liquidating damage provisions that may imply that the contract could be net settled.

Net settlement through a market mechanism

In this form of net settlement, one of the parties is required to deliver an asset, but there is an established market mechanism that facilitates net settlement outside the contract. ASC 815-10-15-110 through 15-116 provide guidance on indicators to consider in assessing whether an established market mechanism exists. A key aspect of a market mechanism is that one of the parties to the agreement can be fully relieved

of its rights and obligations under the contract. Ancillary services information is posted to PJM eMKT, a market participant interface. We understand there may be some activity in this market; however, it does not appear that there is sufficient liquidity that provides the ability of parties to be relieved of their rights and obligations. The key factor in this evaluation is that there are no quoted market prices and no buyers standing ready to transact via eMKT.

Net settlement by delivery of an asset that is readily convertible to cash

Whether there is an active spot market for the particular product being sold under the contract is the key factor in assessing whether an asset is readily convertible to cash. Current market conditions should always be considered in this analysis. To be deemed an active spot market, a market must have transactions with sufficient frequency and volume to provide pricing information on an ongoing basis. In addition, quoted prices from that market will be readily available on an ongoing basis. See UP 3.2.3.3 for further information on the determination of whether a market is active. Based on the current structure of the markets, we are not aware of any active spot markets for PJM ancillary services.

Overall conclusion

We are not aware of a market mechanism or active spot market for PJM ancillary services contracts, and thus we believe that derivative accounting is generally not applicable to these contracts. Instead, the contracts are accounted for as executory contracts or a legal obligation. However, a reporting entity should evaluate all current facts and circumstances in concluding on the appropriate accounting for a specific PJM ancillary services contract. In addition, a reporting entity should monitor its conclusion periodically because markets may evolve, potentially rendering this type of contract a derivative. Finally, a reporting entity should evaluate the contract to determine if there are any embedded derivatives that require separation.

Reporting entities may also consider conditionally designating PJM ancillary services contracts under the normal purchases and normal sales scope exception if physical delivery is probable throughout the life of the contract and the other criteria for application of this exception are met (ASC 815-10-15-22 through 15-51 as applicable). If a conditionally designated normal purchases and normal sales contract meets the definition of a derivative at a later date, it would be accounted for as a normal purchases and normal sales contract from the time the contract becomes a derivative. Absent such a designation, the reporting entity would be required to record the contract at its fair value at the time it becomes a derivative. See UP 3.3.1 for further information on the normal purchases and normal sales scope exception.

4.6 Other markets

As depicted in Figure 4-1, in addition to PJM, there are a number of other RTOs in the United States, most of which also have transmission capacity, congestion, and ancillary services instruments. Although there may be differences in the names of these instruments and some of the specifics of their features, in general, the key considerations and evaluation of the accounting for the instruments will be similar.

Therefore, reporting entities may consider the information included in the rest of UP 4 when evaluating contracts executed in other markets. To assist in this analysis, Figure 4-11 highlights the primary RTOs in the United States and related products, along with mapping to the equivalent PJM product.

Figure 4-11

Summary of regional transmission organizations and related instruments

Market	Capacity	Transmission congestion	Ancillary services
PJM Interconnection, L.L.C. (UP 4.3)	RPM	ARRs and FTRs	Ancillary services
California Independent System Operator Corporation	Not applicable	Congestion Revenue Rights: function similar to FTRs in PJM	Ancillary services: considerations are generally consistent with those in PJM
Electric Reliability Council of Texas (ERCOT)	Not applicable	Congestion Revenue Rights: function similar to FTRs in PJM	Ancillary services: considerations are generally consistent with those in PJM
ISO New England Inc.	Capacity Market: functions similar to RPM in PJM	ARRs and FTRs: function similar to ARR and FTRs in PJM	Ancillary services: considerations are generally consistent with those in PJM
Midcontinent Independent System Transmission Operator, Inc. (MISO)	Voluntary capacity market: market participants obtain “planning resource credit” that allows them to demonstrate they have adequate resources; functions similar to RPM in PJM	ARRs and FTRs: function similar to ARR and FTRs in PJM	Not applicable

Market	Capacity	Transmission congestion	Ancillary services
New York Independent System Operator, Inc.	Capacity market	Transmission Congestion Contracts: consider guidance on ARR in PJM for contributed transmission congestion contracts	Ancillary Services: considerations are generally consistent with those in PJM
Southwest Power Pool	Not applicable	ARRs and Transmission Congestion Rights (TCRs): function similar to ARRs and FTRs in PJM	Ancillary Services: considerations are generally consistent with those in PJM

Note that Figure 4-11 focuses on non-energy related products. Each RTO also facilitates transactions involving energy.

In late 2014, a regional Energy Imbalance Market (EIM) operated by the California ISO was created. The EIM is developing a governance process that, although closely coordinated, is separate and distinct from the California ISO. The EIM anticipates continuing to add new members and increasing its regional footprint, which could ultimately lead to changes in the scope and configuration of the California ISO.

The primary differences in the RTOs are in terminology. However, there are certain variations in the functions of the RTOs that should be noted. The ISO-NE does not allow conversion of its ARRs into FTRs. Although these instruments would be accounted for individually, it does expose the holder to greater price discrepancies as they cannot match the congestion variances without bidding on the FTRs. Only the PJM offers FTR option instruments as discussed in 4.4.1. The frequency and duration of the FTR auctions vary by RTO.

4.7 PJM: key terms

Figure 4-12 includes the definition of selected key PJM-related terms used in this chapter. The definitions are obtained from PJM Manual 35: *Definitions and Acronyms* (revision 22, effective date February 28, 2013).

Figure 4-12
Key PJM terms

Term	Definition
Auction Revenue Rights (ARR)	Entitlements allocated annually to Firm Transmission Service Customers that entitle the holder to receive an allocation of the revenues from the Annual FTR Auction.
Available Transfer Capability (ATC)	The amount of energy above “base case” conditions that can be transferred reliably from one area to another over all transmission facilities without violating any pre- or post-contingency criteria for the facilities in the PJM Control Area under specified system conditions.
Base Residual Auction	Allows for the procurement of resource commitments to satisfy the region’s unforced capacity obligation and allocates the cost of those commitments among the LSEs through the Locational Reliability Charge.
Capacity Resource	Includes megawatts of net capacity from existing or planned generation Capacity Resources or load reduction capability provided by Demand Resources or ILR in the PJM Region.
Daily Unforced Capacity Obligation	Equals the LSE’s Obligation Peak Load in the zone/area * the Final Zonal RPM Scaling Factor * the Forecast Pool Requirement for an LSE in a zone/area.
Day-Ahead Energy Market	A day-ahead hourly forward market in which PJM market participants may submit offers to sell and bids to buy energy. The results of the Day-Ahead Energy Market are posted daily at 4:00 p.m. and are financially binding. The Day-Ahead Energy Market is based on the concept of Locational Marginal Pricing and is cleared using least-price security-constrained unit commitment and dispatch programs.
Delivery Year	Planning period for which resources are being committed and for which a constant load obligation for the entire PJM region exists. For example, the 2007/2008 Delivery Year corresponds to the June 1, 2007–May 31, 2008 Planning Period.
eFTR	A computerized information system developed as an Internet application that is the Market Participant interface to the monthly FTR Auction. This application also facilitates trading of Fixed Transmission Rights on a bilateral basis (secondary market trading).

Term	Definition
eMKT	A computerized information system developed as an Internet application that is the Market Participant interface to the PJM Day-Ahead Energy Market and Real-Time Energy Market. This application provides an interface for Market Participants to submit Generation Offer Data Demand Bids, Increment Offers, Decrement Bids and Regulation Offers and to view Day-Ahead Energy Market Results and Regulation Market Results on a daily basis.
Equivalent Demand Forced Outage Rate (EFORd)	A measure of the probability that [a] generating unit will not be available due to forced outages or forced deratings when there is a demand on the unit to generate.
Financial Transmission Right (FTR)	A financial instrument that entitles the holder to receive compensation for certain congestion-related transmission charges that arise when the grid is congested and differences in locational prices result from the redispatch of generators out of merit order to relieve that congestion.
Firm Transmission Service	Transmission service that is intended to be available at all times to the maximum extent practicable, subject to an emergency, and unanticipated failure of a facility, or other event beyond the control of the owner or operator of the facility or PJM.
FTR Auction	A monthly market for FTR trading that is administered by PJM in which PJM Market Participants and Transmission Customers may submit offers to sell and bids to buy on-peak or off-peak FTRs. FTRs awarded in this auction have a term of one calendar month.
Incremental Auctions	Allow for an incremental procurement of resource commitments to satisfy an increase in the region's unforced capacity obligation due to a load forecast increase or a decrease in the amount of resource commitments due to a resource cancellation, delay, derating, EFORd increase, or decrease in the nominated value of a Planned Demand Resource.
InSchedules	A computerized information system, developed by PJM as an Internet application, that allows Load Aggregators and LDCs to provide and obtain information needed to schedule Internal Transactions under the Customer Choice Program.
Internal Transaction	An energy transaction between two parties in which the path of the energy remains inside the PJM RTO borders.
Load Aggregator (LA)	A licensed entity that may provide (sell) energy to retail customers within the service territory of a Local Distribution Company. Also known as Electric Generation Supplier (EGS).

Term	Definition
Load Serving Entity (LSE)	Any entity (or the duly designated agent of such an entity), including a load aggregator or power marketer that (a) serves end-users within the PJM Control Area, and (b) is granted the authority or has an obligation pursuant to state or local law, regulation, or franchise to sell electric energy to end-users located within the PJM Control Area.
Local Distribution Company (LDC)	A company in whose service territory Load Aggregators are providing energy to retail customers and whose distribution system is being used to transport the energy. Also known as Electric Distribution Company (EDC).
Locational Marginal Price (LMP)	The hourly integrated market clearing marginal price for energy at the location the energy is delivered or received.
Locational Reliability Charge	Fee applied to each LSE that serves load in PJM during the Delivery Year. Equal to the LSEs Daily Unforced Capacity Obligation multiplied by the applicable Final Zonal Capacity Price.
Market Participant	A Market Buyer or a Market Seller, or both.
Obligation Peak Load	The summation of the weather normalized coincident summer peaks for the previous summer of the end-users for which the Party was responsible on that billing day.
PJM Region	PJM Region represents the aggregate of the PJM Mid-Atlantic Control Zone and the PJM West Region.
Planned Demand Resource	A Demand Resource that does not currently have the capability to provide a reduction in demand or to otherwise control load, but that is scheduled to be capable of providing a reduction or control on or before the start of the Delivery Year for which the resource is to be committed.
Planning Period	The 12 months beginning June 1 and extending through May 31 of the following year. As changing conditions may require, the Markets and Reliability Committee may recommend other Planning Periods to the PJM Board of Managers.
Sink	<ul style="list-style-type: none"> □ The bus, buses, company, or pool receiving the transferred energy to evaluate ATC transfers for a given path using generation or load changes, or □ The point of receipt of the energy in a PJM InSchedules Contract.

Term	Definition
Source	<ul style="list-style-type: none"> □ The bus, buses, company, or pool supplying the energy used to evaluate ATC transfers for a given path using generation or load changes, or □ The point of delivery of the energy in a PJM InSchedules contract.
Unforced Capacity (UCAP)	Installed capacity rated at summer conditions that are not on average experiencing a forced outage or forced derating, calculated for each Capacity Resource on the 12-month period from October to September without regard to the ownership of or the contractual rights to the capacity of the unit.
Zonal Capacity Price	The price of UCAP in a Zone that an LSE that has not elected the FRR Alternative is obligated to pay for a Delivery Year. Zonal Capacity Prices are calculated in the Base Residual Auction or the Second Incremental Auction clearing process as the sum of (1) the marginal value of system capacity for the PJM Region; (2) the Locational Price Adder, if any, for such zones in a constrained Locational Deliverability Area (LDA); and (3) an adjustment in the Zone, if required, to account for any resource make-whole payments. <i>Preliminary Zonal Capacity Prices</i> are the result of the clearing of the Base Residual Auction. <i>Adjusted Zonal Capacity Prices</i> are the result of the clearing of the Second Incremental Auction. <i>Final Zonal Capacity Prices</i> are determined after the ILR Resources are certified (3 months prior to the Delivery Year).
Zone	An area within the PJM Region or such areas that may be combined as a result of mergers and acquisitions; or added as a result of the expansion of the boundaries of the PJM Region. A Zone will include any Non-Zone Network Load located outside the PJM Region that is served from inside a particular Zone.

Chapter 5: ***Natural gas***

5.1 Chapter overview

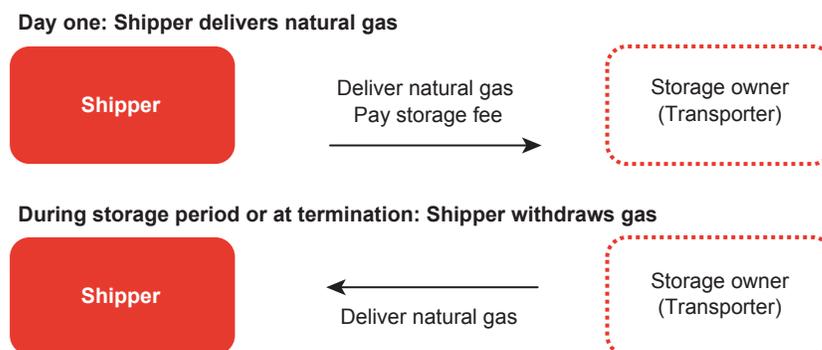
Natural gas local distribution companies, utilities, power generation companies, and natural gas traders procure natural gas for a variety of reasons including for the production of energy, resale to customers, and trading purposes. Typical contracts include physical forward contracts for the purchase or sale of natural gas itself and arrangements for natural gas storage and capacity. Continuing changes in natural gas storage and transportation markets have led to the evolution of new arrangements and increased accounting complexity. This chapter provides accounting guidance for common natural gas-related agreements, including natural gas storage, park and loan, capacity, and optimization agreements.

5.2 Physical natural gas storage

In a basic physical natural gas storage arrangement, natural gas is injected into a storage facility and is withdrawn based on terms and at intervals agreed with the storage owner as depicted in Figure 5-1.

Figure 5-1

Basic physical natural gas storage arrangement



The owner of the natural gas storage (herein referred to as the “storage owner” or “transporter”) is not entitled to sell or loan the natural gas but is obligated to store the natural gas for the customer (shipper). The storage owner earns a service fee for the shipper’s injection, storage, and withdrawal of the natural gas. The storage agreement specifies the storage location, duration, limits on injections and withdrawals, maximum storage capacity, and other terms.

5.2.1 Accounting for natural gas storage arrangements

A physical natural gas storage arrangement should be evaluated using the commodity contract assessment framework (see UP 1). After identifying the contract deliverables, the parties should first determine whether the storage agreement contains a lease. If the contract does not contain a lease, the reporting entity should next assess whether it is a derivative in its entirety. If not, a reporting entity should consider whether the contract contains any embedded derivatives requiring separation from the host contract. If neither lease nor derivative accounting apply, the parties should account for the physical natural gas storage agreement as an executory contract (i.e., on an

accrual basis). The accounting model applied impacts initial and subsequent recognition and measurement as discussed in the following sections.

5.2.1.1 Lease accounting

ASC 840 provides guidance for determining whether an agreement that transfers the right to use identified property, plant, or equipment should be accounted for as a lease. In accordance with this guidance, an arrangement contains a lease if both of the following conditions are met:

- Fulfillment of the arrangement is dependent on the use of specified property, plant, or equipment
- The arrangement conveys the right to control use of the property, plant, or equipment

Many contracts for physical natural gas storage specify a storage facility. A facility-specific natural gas storage agreement contains a lease if any one of the conditions set forth in ASC 840-10-15-6 is met. Those conditions include consideration of whether the purchaser has the right or ability to control the property, plant, or equipment, and whether it is remote that one or more parties other than the purchaser will take more than a minor amount of the output or other utility of the property, plant, or equipment. An agreement that conveys the right to use the entire pipeline capacity will likely contain a lease. In contrast, if an agreement conveys only a portion of the capacity of the storage facility, it will generally not contain a lease. For example, a storage agreement that provides the shipper with all of the storage capacity of a particular facility for a period of time may be a lease, whereas an agreement for only 25% of the capacity likely is not as the capacity is not considered specifically identifiable in the context of the overall facility (i.e., it is not a specific part of the storage facility). See UP 2.2 for further information on determining whether an arrangement contains a lease.

Although a natural gas storage agreement could contain a lease, in most cases these contracts convey the right to use only a portion of the storage facility. In such cases, none of the ASC 840-10-15-6 conditions would be met. If the contract does not contain a lease, the parties should then consider whether the contract is a derivative in its entirety or includes an embedded derivative.

Note about recent standard setting

The FASB issued ASC 842, *Leases*, in February 2016, which amends the guidance discussed in this chapter. The amended guidance will be effective for public companies for annual reporting periods beginning after December 15, 2018. Non-public companies have an additional year.

5.2.1.2 Derivative accounting

A natural gas storage contract that specifies a storage facility provides the customer with temporary use of a portion of the storage facility (similar to renting space in a building). Derivative accounting typically does not apply to this type of contract

because the criterion of net settlement is not met. Nonetheless, the parties should evaluate whether a natural gas storage contract is a derivative in its entirety in accordance with the criteria in ASC 815-10-15-83. Figure 5-2 highlights the evaluation considerations for a typical natural gas storage agreement.

Figure 5-2

Does a typical physical natural gas storage agreement meet the definition of a derivative?

Guidance	Evaluation	Comments
Notional amount and underlying	Met	<ul style="list-style-type: none"> □ Notional (quantity of storage) and underlying (price for the storage) are typically specified.
No initial net investment	Met	<ul style="list-style-type: none"> □ No initial net investment is typically required.
Net settlement	Generally not met	<ul style="list-style-type: none"> □ Contractual net settlement is typically not permitted in a physical storage agreement (see UP 5.3 for information on virtual storage). □ Generally, there is no market mechanism for net settlement and no active market for spot sales of natural gas storage; however, markets should be monitored to determine if a market mechanism or an active market develops.

In general, we would not expect a contract for physical natural gas storage to be accounted for as a derivative in its entirety because it fails the net settlement criterion.

ASC 815-10-15-83(c)

Net settlement. The contract can be settled net by any of the following means:

1. Its terms implicitly or explicitly require or permit net settlement.
2. It can readily be settled net by a means outside the contract.
3. It provides for delivery of an asset that puts the recipient in a position not substantially different from net settlement.

However, developing markets for physical natural gas storage in some parts of the United States and Canada could change that conclusion in certain locations. Because it is the *storage agreement* being assessed, the evaluation is based on whether storage itself has the characteristic of net settlement. The fact that the natural gas in storage may have the characteristic of net settlement (i.e., the natural gas may be readily convertible to cash) has no bearing on this evaluation. Factors to consider in assessing whether physical storage contracts for a specified storage facility meet the net

settlement criterion are discussed in the following paragraphs. See UP 3.2.3 for further information on the overall application of the net settlement criterion. See UP 5.3 for information about virtual storage.

Net settlement under contract terms

When evaluating whether the net settlement criterion is met, a reporting entity should first consider whether the contract terms explicitly or implicitly provide for net settlement of the entire contract. Natural gas storage contracts related to the use of a specified facility typically do not permit explicit net settlement. However, the type of contract and its terms should be carefully reviewed to ensure that there are no implicit net settlement terms, such as liquidating damage provisions, that may imply that the contract could be net settled.

Net settlement through a market mechanism

In this form of net settlement, one of the parties is required to deliver an asset, but there is an established market mechanism that facilitates net settlement outside the contract. ASC 815-10-15-110 through 15-116 provide guidance on indicators to consider in assessing whether an established market mechanism exists. A key aspect of a market mechanism is that one of the parties to the agreement can be fully relieved of all of its rights and obligations under the contract. We are not aware of any markets that allow for net settlement of contracts for natural gas storage in the United States such that a provider has the ability to be relieved of its full rights and obligations under a previously executed contract.

Net settlement by delivery of an asset that is readily convertible to cash

Whether there is an active spot market for the particular asset being sold under the contract is the key factor in assessing whether an asset is readily convertible to cash. In assessing this criteria, the asset being delivered under the contract and the ability to convert that asset to cash upon receipt should be considered. The nature of the asset and the structure of the markets may impact the conclusions in this analysis. Based on the nature of natural gas storage contracts, we do not believe this criteria would apply as the purchaser of the storage does not have the ability to sell the storage once it is obtained (i.e., the purchaser must use the capacity as soon as it is “delivered” and thus it cannot be converted to cash).

Overall conclusion

We are not aware of a market mechanism or active spot market for natural gas storage, and thus we believe that derivative accounting is generally not applicable to these contracts. However, a reporting entity should evaluate all facts and circumstances in concluding on the appropriate accounting for a specific natural gas storage contract. In addition, a reporting entity should monitor its conclusion periodically because markets evolve, potentially rendering this type of contract a derivative. Reporting entities also should evaluate the contract to determine if there are any embedded derivatives that require separation (assuming the contract does not meet the definition of a derivative in its entirety, refer to UP 3.4).

Reporting entities may also consider conditionally designating physical natural gas storage agreements under the normal purchases and normal sales scope exception if physical delivery is probable throughout the life of the contract and the other criteria for application of this exception are met (ASC 815-10-15-22 through 15-51, as applicable). In this circumstance, the reporting entity would document the requirements to elect the normal purchases and normal sales scope exception for effective designation at a future date. If a conditionally designated normal purchases and normal sales contract meets the definition of a derivative at a later date, the contract would be accounted for as normal at the time it meets the definition of a derivative. Refer to UP 3.3.1 for discussion around accounting for a normal contract. Absent such advanced designation, the reporting entity would be required to record the contract at its fair value at the time it becomes a derivative. However, it could be subsequently designated as normal after initial recognition. See UP 3.3.1 for further information on the normal purchases and normal sales scope exception.

5.2.1.3 *Executory contract accounting*

We would generally expect a physical natural gas storage agreement to be accounted for as an executory contract. In such cases, reporting entities should also evaluate whether there are any embedded derivatives (e.g., pricing mechanisms) that require separation from the host contract (see UP 3.4 for information on evaluating embedded derivatives).

In accounting for a natural gas storage contract following an executory contract model, the shipper should expense the cost of storage as a period cost when incurred. The storage owner should recognize revenue from storage fees over the period of the contract in accordance with the revenue guidance effective at the time of recognition. See UP 5.2.2 for a discussion of the impairment considerations associated with natural gas in storage and other natural gas inventory.

Application examples — natural gas storage agreements

The following examples provide guidance on how reporting entities should account for natural gas storage.

EXAMPLE 5-1

Shipper's accounting for a physical gas storage agreement

On April 1, 20X1, Ivy Power Producers (IPP) enters into a natural gas storage agreement with Guava Gas Company (GGC). The storage location and other key terms are specified in the agreement. On May 1, 20X1, IPP purchases 10,000 MMBtus of natural gas for \$4.00/MMBtu on the spot market and injects the natural gas into the GGC storage facility. IPP is required to withdraw the natural gas on December 1, 20X1. The storage facility's total capacity is 100,000 MMBtus of natural gas. IPP pays a storage fee of \$2,000 per month, regardless of the amount stored.

On December 1, 20X1, IPP withdraws the natural gas and sells it on the spot market.

For purposes of this example, the spot and forward prices (forward price for delivery in December 20X1) of natural gas are as follows (\$/MMBtu):

Date	Spot	Forward
May 1, 20X1	\$4.00	\$5.00
June 1, 20X1	4.00	4.75
June 30, 20X1	3.00	4.50
September 30, 20X1	3.50	5.50
December 1, 20X1	6.00	—

How should IPP account for the natural gas held in storage, as well as the expenses associated with this agreement?

Analysis

The natural gas storage agreement would not contain a lease because the contract is for use of only a portion of the facility and the arrangement does not meet any of the other conditions in ASC 840-10-15-6. Derivative accounting would also not apply due to the factors discussed in UP 5.2.1.2 related to net settlement not being met. Therefore, the storage agreement would be accounted for as an executory contract and the natural gas stored would be included in IPP's inventory.

IPP would record the following journal entries to account for the storage of natural gas in inventory and the expenses associated with this agreement (amounts in thousands). For purposes of this example, it is assumed that a lower of cost or market (LOCOM) charge is not necessary but would be considered in periods of declining prices. Refer to UP 5.2.2.2.

Date	Journal entries	Cash	Fuel inventory	Fuel revenue	Fuel expense
1 05/01	Initial purchase of inventory (10,000 × \$4.00/MMBtu)	(\$40)	\$40		
2 Monthly	To record storage fees (\$2,000 per month)	(2)			\$2
3 12/01	To record the sale of natural gas inventory (10,000 × \$6.00 spot)	60	(40)	(\$60)	40

In this example, the revenue is shown gross. In practice, IPP would need to assess whether gross versus net presentation would be appropriate (see UP 3.7).

No journal entries would be recorded by IPP when it first enters into the agreement (April 1, 20X1) because the natural gas storage agreement is an executory contract and there is no activity at that date. In addition, no journal entries are needed to reflect the injection into storage; natural gas in storage is reflected as part of a reporting entity's fuel inventory.

EXAMPLE 5-2**Storage owner's accounting for a physical natural gas storage agreement**

Assume the same fact pattern as in Example 5-1.

How should GGC account for the natural gas in storage, as well as the revenue from this arrangement?

Analysis

GGC would not record any journal entries when the natural gas inventory is received from the shipper or when it is withdrawn from storage. Title to the natural gas remains with the shipper during the storage period, so GGC would not record natural gas held for a third party. GGC should record the storage fees as revenue over the contract period (i.e., monthly).

If GGC had the right to use and then replace the gas at a later date, the accounting for a physical park and loan transaction would apply (see UP 5.4.1).

5.2.2 Accounting for natural gas held in storage

Reporting entities may hold natural gas in inventory ("working gas"), as well as gas held in storage fields that is not intended for sale, but is required for efficient and reliable operation of the facility ("base" or "cushion" gas). The nature and intended use of natural gas held by a reporting entity will impact its balance sheet classification, as well as the impairment model used in subsequent accounting.

5.2.2.1 Balance sheet classification**Figure 5-3****Balance sheet classification of natural gas**

Category	Description	Classification
Working gas	<ul style="list-style-type: none"> □ Portion of natural gas held by the reporting entity that is expected to be sold or used in operations 	Inventory (current or noncurrent depending on expected timing of sale or use)
Base or cushion gas	<ul style="list-style-type: none"> □ Portion of natural gas necessary to force the saleable gas from a storage field into the transmission system and for system balancing □ Not intended for sale and will not be fully recoverable if a storage project or related pipeline is abandoned 	Generally classified as part of property, plant, and equipment; represents a permanent investment necessary to use a storage facility and maintain reliability

Any volumes held in excess of amounts required for system deliverability or system balancing are considered natural gas for resale and should be classified as inventory.

5.2.2.2 *Impairment considerations*

Natural gas held in storage is subject to potential impairment. The impairment model applied will vary depending on whether the natural gas is classified as part of inventory or as property, plant, and equipment.

Natural gas classified as inventory

Natural gas classified as inventory is subject to the inventory accounting guidance in ASC 330, *Inventory*. Natural gas prices are volatile and a reporting entity that owns natural gas inventory may need to assess whether LOCOM adjustments to its carrying value are necessary as of the reporting date. ASC 330 establishes LOCOM as the guiding principle to be used in assessing whether cost or a lower estimate of realizable value should be used in valuing inventories. See UP 11.2 for information on evaluating LOCOM adjustments for inventory, including natural gas. See also UP 11.6 for information on additional LOCOM inventory considerations for regulated utilities.

Natural gas classified as part of property, plant, and equipment

Stored gas that is determined to be base or cushion gas is generally classified as property, plant, and equipment because it is necessary for a facility to operate. This type of natural gas should be accounted for and evaluated for impairment in accordance with the general guidance for plant. See UP 12 for further information.

Ongoing standard setting

In July 2015, the FASB issued ASU 2015-11, *Simplifying the measurement of inventory*, which simplifies the LOCOM analysis discussed above. This ASU is effective in fiscal years beginning after December 15, 2016 and may impact the evaluation of inventory impairment.

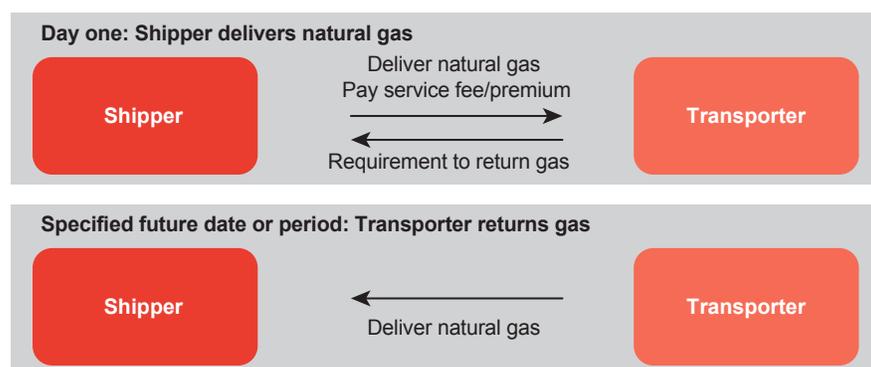
5.3 *Virtual storage or virtual park and loan*

Virtual storage (also known as virtual park and loan) is a common type of natural gas-related transaction. Although different terminology may be used to describe these transactions, the term “virtual storage” is used throughout this guide to refer to all similar arrangements.

In a typical virtual storage arrangement, a physical storage location is not specified. The shipper delivers natural gas to an agreed-upon pipeline location and the transporter takes custody of the natural gas. The transporter is required to return the same quantity of natural gas on a specified future date. The shipper does not have access to the natural gas during the period of the arrangement. Virtual storage arrangements are structured to allow the transporter to trade natural gas depending on price fluctuations.

No cash is exchanged in a virtual storage arrangement except for a fee paid by the shipper for the ability to “park” the natural gas for a specified period of time. The upfront service fee or premium is intended to compensate the transporter for the difference in the spot and forward natural gas prices between the dates of initial receipt and return (the seasonal spread amount). In addition, the transporter has the risks and rewards of ownership of the natural gas from the time the natural gas is delivered to the time it is returned to the shipper. A typical arrangement is depicted in Figure 5-4:

Figure 5-4
Typical virtual storage arrangement



The terms of virtual storage arrangements may vary. For example, the shipper may be able to choose both the date of initial delivery and the withdrawal (subsequent return) date. Additional optionality will increase the price of the arrangement. The key differentiating factor in a virtual storage arrangement compared with traditional storage is that no physical storage location is specified or included as part of a virtual storage arrangement.

5.3.1 Accounting for virtual storage

Lease accounting for virtual storage transactions is not applicable because this type of agreement does not provide the right to use identified property, plant, or equipment. Therefore, in accordance with the commodity contract accounting framework described in UP 1, a virtual storage arrangement should next be assessed to determine if it is a derivative in its entirety or if it includes any embedded derivatives.

5.3.1.1 Derivative accounting

A virtual storage agreement is not a derivative in its entirety because it requires an initial net investment, as summarized in Figure 5-5.

Figure 5-5

Does a virtual storage agreement meet the definition of a derivative?

Guidance	Evaluation	Comments
Notional amount and underlying	Met	<input type="checkbox"/> Notional (quantity of gas to be injected) and underlying (market price of the gas).
No initial net investment	Not met	<input type="checkbox"/> Shipper must deliver natural gas at inception that is equal to the amount that will be returned by the transporter.
Net settlement	Met	<input type="checkbox"/> A firm commitment to receive or deliver natural gas in the future would generally meet the criteria for net settlement.

The initial net investment criterion is discussed in ASC 815-10-15-83(b) and ASC 815-10-15-95.

Excerpt from ASC 815-10-15-95

A derivative instrument does not require an initial net investment in the contract that is equal to the notional amount (or the notional amount plus a premium or minus a discount) or that is determined by applying the notional amount to the underlying.

A virtual storage agreement typically requires that the shipper initially deliver natural gas to the transporter in a quantity equal to the amount that will be returned in the future. The shipper also pays a premium that is based on the seasonal spread value. The premium is derived from the expected price differences between the time of injection (initial delivery) and subsequent withdrawal (subsequent return). Because the contract requires initial delivery of natural gas equal to the notional amount of the returned natural gas and a fee that accounts for the seasonal spread, the contract contains an initial net investment and therefore is not a derivative in its entirety. Further evaluation is then required to determine if the contract includes an embedded derivative that requires separation from the host contract, or if other accounting is applicable.

5.3.1.2 Embedded derivative analysis

Although a virtual storage arrangement is not a lease and does not qualify as a derivative in its entirety, as outlined in Figure 5-5, it should be evaluated for potential embedded derivatives. The shipper would record a receivable from the transporter for the return of a specific quantity of natural gas on a specified future date. The value of the receivable will fluctuate with changes in the price of natural gas. This linkage to the price of natural gas would be the potential embedded derivative that would need to be evaluated for bifurcation.

Figure 5-6 outlines the analysis that would be performed on this embedded feature.

Figure 5-6

Does a virtual storage agreement contain an embedded derivative that requires separation?

Guidance	Evaluation	Comments
Economic characteristics of the embedded are not clearly and closely related to the host	Met	<ul style="list-style-type: none"> □ The host contract is a receivable (shipper) or liability (transporter) (i.e., a debt host). □ Changes in the price of natural gas are not clearly and closely related to a debt host instrument.
Hybrid instrument is not remeasured at fair value under otherwise applicable U.S. GAAP	Met	<ul style="list-style-type: none"> □ The virtual storage agreement is not remeasured at fair value.
A separate instrument with the same terms as the embedded derivative would be a derivative instrument subject to ASC 815	Met	<ul style="list-style-type: none"> □ A firm commitment to receive or deliver natural gas in the future would meet the definition of a derivative. □ The embedded derivative may be eligible for hedge accounting in some circumstances (see the response to Question 5-4).

This approach results in initial recognition of a receivable for the shipper with an embedded derivative instrument linked to the price of natural gas that would be bifurcated.

In accordance with ASC 815-15-30-2, the embedded derivative should be separated from its host contract at fair value at inception (i.e., generally at zero on day one for non-option derivatives, resulting in no day one gain or loss on the derivative). The remaining carrying value of the storage contract is assigned to the host contract. Furthermore, although the discussion above is from the perspective of the shipper, the transporter would follow the same accounting model. See the response to Question 5-3 for information on whether the normal purchases and normal sales scope exception can be applied to the embedded derivative.

The model discussed above outlines a view that the injection of the natural gas is a prepayment of the future purchase of natural gas. While this model may be the predominant model applied in practice, there are other models that may exist that could be more appropriate in given circumstances. Additionally, upon transitioning to ASC 606 *Revenue from Contracts with Customers*, the impacts of this standard to these transactions should be considered.

Question 5-1

How should a reporting entity present virtual storage activities on the balance sheet?

PwC response

It depends. We believe reporting entities may present the separated embedded derivative together with the related receivable or payable on the balance sheet. The SEC staff has stated that an embedded derivative that has been separated from a host contract may be presented on a combined basis with the related host contract on the balance sheet, because the combined presentation is reflective of the overall cash flows for that instrument. Reporting entities should apply a consistent accounting policy to the presentation of similar contracts.

Question 5-2

How should a reporting entity present virtual storage activities in the income statement?

PwC response

It depends. In considering income statement presentation for virtual storage transactions for both the shipper and transporter, reporting entities should assess whether net or gross presentation of natural gas purchases and sales is appropriate. In general, this determination will depend on the nature of the reporting entity's virtual storage activities and its purpose for entering into virtual storage transactions. Transactions entered into for trading purposes as well as certain physically settled nontrading activities should be presented net in the income statement. The determination of whether a derivative instrument held by a reporting entity is being held for trading purposes is a matter of judgment and will be based on the reporting entity's intent and the specific facts and circumstances. See UP 3.7 for further information on evaluating whether gross or net income statement presentation of derivative-related trading activities is appropriate.

5.3.1.3 Application examples – virtual storage

The following examples illustrate the journal entries for virtual storage.

EXAMPLE 5-3**Shipper's accounting for a virtual natural gas storage agreement**

On April 1, 20X1, Rosemary Electric & Gas Company (REG), the shipper, enters into a natural gas storage agreement with Guava Gas Company (GGC), the transporter. There is no natural gas storage location specified. On May 1, 20X1, REG purchases 10,000 MMBtus of natural gas from the spot market and delivers (parks) it to GGC at the SoCal Border trading point (a market hub for natural gas located in California). REG is required to withdraw the natural gas on December 1, 20X1. REG pays a fee of \$10,000 for natural gas injection and withdrawal (referred to herein as the virtual storage fee), equal to the spot-to-forward price difference at the date of injection. Spot

and forward prices (forward price for delivery in December 20X1) of natural gas are as follows (\$/MMBtu):

Date	Spot	Forward
May 1, 20X1	\$4.00	\$5.00
June 30, 20X1	3.00	4.50
September 30, 20X1	3.50	5.50
December 1, 20X1	6.00	—

How should REG account for the virtual storage arrangement?

Analysis

At the time of initial delivery of the natural gas, REG would record a receivable (valued based on the spot price of natural gas on the date of initial delivery to GGC plus the fee paid that represents the spot to forward difference) and an embedded derivative. REG would record the following journal entries to account for this agreement (amounts in thousands).

Date	Journal entries	Cash	Receivable	Fuel inventory	Derivative	Income statement
1 05/01	Initial purchase of natural gas (10,000 × \$4.00)	(\$40)		\$40		
2 05/01	Delivery of natural gas		\$40	(40)		
3 05/01	Virtual storage fee paid (see note 1)	(10)	10			
4 06/30	Record change in value (10,000 × (\$5.00 – 4.50)) (see note 2)				(\$5)	\$5
5 06/30	Amortize virtual storage fee Accrete receivable (see note 3)		(3) 3			3 (3)
6 09/30	Record change in value (10,000 × (\$4.50 – 5.50))				10	(10)
7 09/30	Amortize virtual storage fee Accrete receivable (see note 3)		(4) 4			4 (4)
8 12/01	Record change in value (10,000 × (\$5.50 – \$6.00))				5	(5)
9 12/01	Amortize virtual storage fee Accrete receivable (see note 3)		(3) 3			3 (3)
10 12/01	Record receipt of natural gas from GGC		(50)	60	(10)	
TOTAL		(\$50)	\$ —	\$60	\$ —	(\$10)

Note 1: The virtual storage fee paid is part of the initial prepayment for the future return of natural gas.

Note 2: As discussed in the response to Question 5-1, the embedded derivative can be combined with the related host contract (i.e., gas to be received) on the balance sheet. For illustration purposes, the amounts are shown separately.

Note 3: The virtual storage fee should be amortized over the benefit period. Additionally, when the receivable is recorded, it is recorded at a discount that can be viewed similar to a zero-coupon bond (i.e., the transferred consideration is based on the spot price at injection and is expected to accrete up to the forward price).

A virtual storage arrangement results in a significantly different carrying value of inventory compared with injecting natural gas in physical storage. In this example, the carrying value of fuel inventory is \$60,000 as of December 1, 20X1. The virtual storage arrangement effectively allows REG to fair value its inventory during the “storage” period because it records an embedded derivative indexed to the price of natural gas. Therefore, REG would recognize the net gain on the change in value of the inventory during the period the natural gas was stored, rather than when the natural gas is sold.

EXAMPLE 5-4

Transporter’s accounting for a virtual natural gas storage agreement

Assume the same facts as in Example 5-3, but from the perspective of the transporter, GGC. Assume GGC sells the natural gas into the spot market on the same day it is received.

How should GGC account for the virtual storage arrangement in accordance with the prepaid forward model?

Analysis

GGC would record a liability when it receives the inventory from the shipper. The day 1 liability would be based on the spot price of natural gas. GGC would record the following journal entries to account for this agreement and the embedded derivative (amounts in thousands):

	Date	Journal entries	Cash	Fuel inventory	Fuel Liability/ Deferred revenue	Derivative	Income statement
1	05/01	Initial receipt of natural gas (10,000 × \$4.00) (see note 1)		\$40	(\$40)		
2	05/01	Sell natural gas inventory received	\$40	(40)			\$0
3	05/01	Virtual storage fee received (see note 1)	10		(10)		
4	06/30	Record change in value (10,000 × (\$4.50 – 5.00)) (see note 2)				\$5	(5)
5	06/30	Recognize deferred revenue (storage fee) Accrete fuel liability (see note 3)			3 (3)		(3) 3
6	09/30	Record change in value (10,000 × (\$5.50 – \$4.50))				(10)	10
7	09/30	Recognize deferred revenue (storage fee) Accrete fuel liability (see note 3)			4 (4)		(4) 4
8	12/01	Record change in value (10,000 × (\$6.00 – 5.50))				(5)	5
9	12/01	Recognize deferred revenue(storage fee) Accrete fuel liability (see note 3)			3 (3)		(3) 3
10	12/01	Purchase natural gas from spot market	(60)	60			
11	12/01	Record delivery of natural gas to REG (10,000 × \$6.00)		(60)	50	10	0
TOTAL			(\$10)	\$ —	\$ —	\$ —	\$10

Note 1: The virtual storage fee received is part of the initial payment received for the future return of natural gas. In the example, the credit of \$10 would be recorded as deferred revenue and the initial receipt of natural gas of \$40 would be recorded as a fuel related liability.

Note 2: As discussed in the response to Question 5-1, the embedded derivative can be combined with the related host contract (i.e., gas to be delivered) on the balance sheet. For illustration purposes, the amounts are shown separately in the table above.

Note 3: The virtual storage fee deferred revenue should be recognized over the period earned. Additionally, when the fuel liability is recorded, it is recorded at a discount that can be viewed similar to a zero-coupon bond (i.e., the transferred consideration is based on spot price at injection and is expected to accrete up to the forward price).

Because the natural gas is sold into the market on the same day it is received, there is no income statement impact on day one. For this example, virtual storage was presumed to be a trading activity and the revenue from the sale and the related cost of goods were presented net in the income statement (\$0 in journal entry 1(b)). See the response to Question 5-2 for further discussion of income statement presentation alternatives.

This example also assumes that GGC sells the natural gas inventory into the spot market on the day it was delivered from the shipper. However, GGC could have stored the natural gas inventory for its own operational purposes, which would have made it subject to valuation at LOCOM (see UP 11.2 for further information). In addition, GGC could have purchased the inventory for delivery to the shipper at a different point in time, to try to capture market movements. It is also likely that GGC would execute multiple purchases and sales of natural gas prior to the date it delivers natural gas. For simplicity, the example assumes that the natural gas was sold and purchased from the market on the same dates as the transactions with the shipper and ignores any additional trades.

Question 5-3

Can a reporting entity apply the normal purchases and normal sales scope exception to a virtual storage agreement?

PwC response

It depends. ASC 815-10-15-22 defines normal purchases and normal sales.

ASC 815-10-15-22

Normal purchases and normal sales are contracts that provide for the purchase or sale of something other than a financial instrument or derivative instrument that will be delivered in quantities expected to be used or sold by the reporting entity over a reasonable period in the normal course of business.

When a shipper is using virtual storage to help manage its fuel for generation or retail customer needs (buying natural gas for a lower price in one period for an assured source of supply in a higher price period), some believe that the normal purchases and normal sales scope exception may be applied. In some cases, a shipper may use virtual storage in lieu of physical storage due to lack of physical storage availability or other operational considerations. Provided that the quantity delivered under the contract is consistent with the shipper's future needs, it may be able to apply the normal purchases and normal sales scope exception if all of the criteria for application of this exception are met (see ASC 815-10-15-22 through 15-51 as applicable). However, the normal purchases and normal sales scope exception would not be applicable if this type of transaction results in purchases and sales in excess of the shipper's actual operational needs, or is associated with a trading operation.

We generally would not expect the transporter to apply the normal purchases and normal sales scope exception because virtual storage arrangements are structured to allow the transporter to trade natural gas depending on price fluctuations, and such transactions are inherently trading activities. Refer to UP 3.3.1 for the accounting considerations related to the normal purchases and normal sales scope exception.

Question 5-4

Can a reporting entity apply hedge accounting to the embedded derivative resulting from a virtual storage agreement?

PwC response

Yes, if all of the hedge accounting requirements in ASC 815 are met. ASC 815-20-25-45 permits an embedded derivative that is accounted for separate from its host contract to be designated as a hedging instrument. Additionally, the bifurcated embedded derivative may be designated as an all-in-one hedge assuming it would meet the criteria in ASC 815-20-25-21 and 25-22. To apply hedge accounting, the reporting entity will need to meet all of the documentation and other hedge accounting requirements. See UP 3.5 for further information on hedge accounting for commodities.

5.3.2 *Financially settled virtual storage*

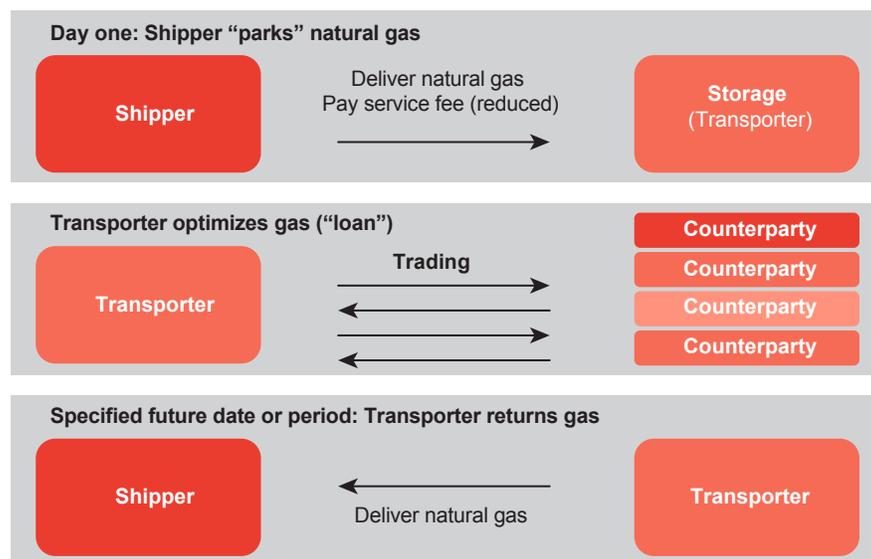
Some virtual storage agreements may be financially settled (i.e., there is no initial delivery of natural gas). Such transactions are basis swaps that lock in the price differential of the natural gas at two points in time. This type of contract is a derivative in its entirety; it specifies an underlying and a notional amount, requires no initial net investment, and has the characteristic of net settlement. Therefore, this type of arrangement should be accounted for at fair value following the derivative accounting guidance in ASC 815.

Furthermore, because the contract is financially settled, it is not eligible for application of the normal purchases and normal sales scope exception.

5.4 *Park and loan*

Figure 5-7 depicts a typical physical park and loan transaction.

Figure 5-7
Physical park and loan transactions



A physical park and loan transaction is similar to a physical natural gas storage arrangement; however, the transporter has the right to withdraw the natural gas during the storage period and may use it for any purpose. The natural gas is parked at a specified storage location and must be returned to the shipper at a specified future date. Similar to a physical storage arrangement, the shipper pays a fee for storage; however, the amount paid may be slightly lower because of the transporter's rights to use (or borrow) the natural gas during the storage period. During the storage period, risk of ownership is transferred to the transporter and the natural gas must be replaced by the transporter in the event of a physical loss (e.g., due to an explosion or natural gas leak).

This section discusses accounting considerations for physical park and loan transactions.

5.4.1 Accounting for park and loan transactions

Shipper accounting

In practice, the shipper's accounting typically follows the physical storage accounting model described in UP 5.2.1.

Transporter accounting

In practice, initial accounting for the arrangement also follows the model for physical storage arrangements outlined in UP 5.2.1, with no accounting for the agreement except for the recognition of storage fee revenue. However, when the transporter borrows the natural gas in storage, it has an obligation to return natural gas to the shipper at a future date. Therefore, at the time it borrows parked natural gas, the transporter would record a liability for the return of the natural gas to the shipper. This liability to deliver natural gas back to the shipper is not a derivative in its

entirety. However, the value of the liability to return natural gas will fluctuate with changes in the price of natural gas. As a result, similar to the accounting for virtual storage discussed in UP 5.3, the liability is a hybrid instrument with an embedded derivative that should be recognized at fair value by the transporter.

5.5 Natural gas capacity

A standard natural gas capacity agreement provides the customer with temporary use of a portion of a natural gas pipeline. Gas capacity agreements may be short- or long-term and may encompass various pricing mechanisms, including fixed capacity fees as well as usage charges.

Issues associated with accounting for natural gas capacity agreements include determining the appropriate accounting model to apply to the agreement in its entirety, as well as related issues associated with unaccounted for gas and natural gas imbalances.

5.5.1 Accounting for natural gas capacity agreements

A natural gas capacity agreement should be evaluated using the commodity contract assessment framework (see UP 1). After identifying the contract deliverables, the parties should first determine whether the capacity agreement contains a lease. If the contract does not contain a lease, the reporting entity should next assess whether it is a derivative in its entirety. If not, a reporting entity should consider whether the contract contains any embedded derivatives requiring separation from the host contract. If neither lease nor derivative accounting apply, the parties would account for the natural gas capacity agreement as an executory contract (i.e., on an accrual basis). The accounting model applied impacts initial and subsequent recognition and measurement, as discussed in the following sections.

5.5.1.1 Lease accounting

Because natural gas capacity agreements involve specified property, plant, or equipment, lease accounting may be applicable. In evaluating whether lease accounting applies, reporting entities should consider whether the criteria in ASC 840 are met. In accordance with this guidance, an arrangement contains a lease if both of the following conditions are met:

- Fulfillment of the arrangement is dependent on the use of specified property, plant, or equipment
- The arrangement conveys the right to control use of the property, plant or equipment

Natural gas capacity agreements typically specify the natural gas pipeline. Such agreements will convey the right to control the use of the pipeline, and thus contains a lease if any one of the conditions set forth in ASC 840-10-15-6 is met. Those conditions include consideration of whether the purchaser has the right or ability to control the property, plant, or equipment, and whether it is remote that one or more parties other than the purchaser will take more than a minor amount of the output or

other utility of the property, plant, or equipment. An agreement that conveys the right to use the entire pipeline capacity will likely contain a lease. In contrast, if an agreement conveys only a portion of the capacity of the storage facility it will generally not contain a lease. For example, a natural gas capacity agreement that provides the shipper with all of the pipeline capacity on a certain path for a period of time may be a lease, whereas an agreement for only 25% of the capacity likely is not, as the capacity is not considered specifically identifiable in the context of the overall pipeline (i.e., it is not a specific part of the pipeline). See UP 2.2 for further information on determining whether an arrangement contains a lease.

In most cases, these contracts are for use of only a portion of the capacity and the requirements of ASC 840-10-15-6 are not met. If the arrangement is determined not to contain a lease, the parties should consider whether the contract is a derivative in its entirety or includes an embedded derivative.

5.5.1.2 *Derivative accounting*

A natural gas capacity contract provides the purchaser with use of a portion of a natural gas pipeline. Derivative accounting typically does not apply to this type of contract because the criterion of net settlement is not met. However, the parties should evaluate whether this type of contract is a derivative in its entirety in accordance with the criteria in ASC 815-10-15-83. Figure 5-8 summarizes key considerations in assessing whether a typical arrangement for the purchase or sale of natural gas capacity is a derivative in its entirety.

Figure 5-8

Does a natural gas capacity contract meet the definition of a derivative?

Guidance	Evaluation	Comments
Notional amount and underlying	Met	<ul style="list-style-type: none"> □ Notional (amount of capacity) and underlying (price for the capacity) are typically specified.
No initial net investment	Met	<ul style="list-style-type: none"> □ No initial net investment is typically required.
Net settlement	Generally not met	<ul style="list-style-type: none"> □ Contractual net settlement is typically not permitted in a natural gas capacity agreement. □ Currently, there is no market mechanism for net settlement and no active market for spot sales of natural gas capacity; however, markets should be monitored to determine if a market mechanism or active market develops.

In general, we would not expect a contract for natural gas capacity to be accounted for as a derivative because it fails the net settlement criterion.

ASC 815-10-15-83(c)

Net settlement. The contract can be settled net by any of the following means:

1. Its terms implicitly or explicitly require or permit net settlement.
2. It can readily be settled net by a means outside the contract.
3. It provides for delivery of an asset that puts the recipient in a position not substantially different from net settlement.

Factors to consider in assessing whether a natural gas capacity contract has the characteristic of net settlement are discussed in the following paragraphs. See UP 3.2.3 for further information on overall application of the net settlement criterion.

Net settlement under contract terms

When evaluating whether the net settlement criterion is met, a reporting entity should first consider whether the contract terms explicitly or implicitly provide for net settlement of the entire contract. Natural gas capacity agreements typically require the capacity owner to provide natural gas capacity (i.e., physical delivery is required). Furthermore, although pricing of a natural gas capacity agreement may be based on locational price differences, the agreement itself does not typically permit net settlement. However, the type of contract and its terms should be carefully reviewed to ensure that there are no implicit net settlement terms or liquidating damage provisions that may imply the contract could be net settled.

Net settlement through a market mechanism

In this form of net settlement, one of the parties is required to deliver an asset, but there is an established market mechanism that facilitates net settlement outside the contract. ASC 815-10-15-110 through 15-116 provide guidance on indicators to consider in assessing whether an established market mechanism exists. A key aspect of a market mechanism is that one of the parties to the agreement can be fully relieved of its rights and obligations under the contract.

Because it is the *capacity agreement* being assessed, the evaluation is based on whether there are buyers standing ready to relieve the reporting entity of all of its rights and obligations for the *natural gas capacity* contract itself. The Federal Energy Regulatory Commission (FERC) provides market pricing for short-term capacity agreements (less than one year). Therefore, short- and long-term natural gas capacity agreements have different characteristics and may have different markets. We understand that there may be some bilateral activity in certain locations within North America, with trading of capacity among market participants to manage excess capacity and meet obligations on a short-term basis for near term delivery, but often not for the full term of a contract. In addition, pipeline companies maintain electronic bulletin boards that provide some information; however, these postings include all transactions, including pre-arranged deals that may be tariff-based. The FERC guidelines regulating transactions on these bulletin boards should be considered in

assessing whether net settlement under a market mechanism exists. Although we understand that there is some activity in the market, it does not appear that there is sufficient liquidity to support the conclusion that a market mechanism exists for natural gas capacity for most contracts. The key factor in this evaluation is whether there are quoted market prices and buyers standing ready to transact for the entire contract (i.e., for the full volume and term of the contract).

Net settlement by delivery of an asset that is readily convertible to cash

Whether there is an active spot market for the particular asset being sold under the contract is the key factor in assessing whether an asset is readily convertible to cash. The nature of the asset and the structure of the markets may impact the conclusions in this analysis. Based on the nature of natural gas capacity contracts, we do not believe this criteria would apply as the purchaser of the capacity does not have the ability to sell the capacity once it is obtained (i.e., the purchaser must use the capacity as soon as it is “delivered” and thus it cannot be converted to cash).

Overall conclusion

We are not aware of a market mechanism or active spot market for natural gas capacity contracts and thus we believe that derivative accounting is generally not applicable to these contracts. However, a reporting entity should evaluate all facts and circumstances in concluding on the appropriate accounting for a specific natural gas capacity contract. In addition, a reporting entity should monitor its conclusion periodically because markets may evolve, potentially rendering this type of contract a derivative. Reporting entities also should evaluate the contract to determine if there are any embedded derivatives that require separation (assuming the contract does not meet the definition of a derivative in its entirety).

Reporting entities may also consider conditionally designating natural gas capacity contracts under the normal purchases and normal sales scope exception if physical delivery is probable throughout the life of the contract and the other criteria for application of this exception are met (ASC 815-10-15-22 through 15-51 as applicable). In this circumstance, the reporting entity would document the requirements to elect the normal purchases and normal sales scope exception for effective designation at a future date. If a conditionally designated normal purchases and normal sales contract meets the definition of a derivative at a later date, it would be accounted for as normal from the time it meets the definition of a derivative. Refer to UP 3.3.1 for discussion around accounting for a normal contract. Absent such advanced designation, the reporting entity would be required to record the contract at its fair value at the time it becomes a derivative. See UP 3.3.1 for further information on the normal purchases and normal sales scope exception.

Question 5-5

Should a reporting entity account for a natural gas capacity contract as a derivative (i.e., a basis swap)?

PwC response

Generally no. A natural gas capacity contract allows the buyer to capture a spread between two locations. A reporting entity can use a natural gas capacity contract to move natural gas through the pipelines and capture a pricing spread between two locations. However, the reporting entity must trade the natural gas capacity contract together with natural gas inventory or market purchases to capture the basis differences. Absent a capacity market, the natural gas capacity contract itself does not settle based on natural gas locational price differences. Thus, such contracts are not derivatives unless they meet the net settlement criterion as discussed above.

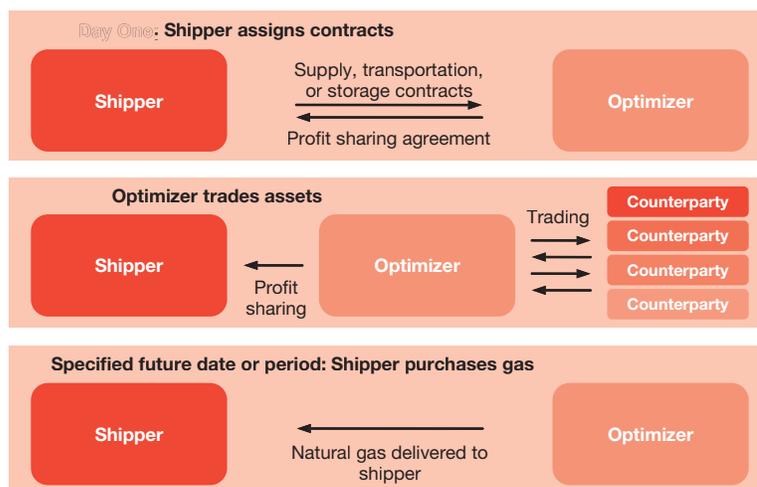
5.5.2 *Accounting for unaccounted for gas*

Unaccounted for gas represents the difference between the amount of gas the shipper supplies to the pipeline system, compared to the amount it withdraws. The main causes for unaccounted for gas include leakage (also referred to as “line loss”), measurement of gas at other than base conditions, different measurement timing for the injection and withdrawal meters, as well as other factors. The magnitude of unaccounted for gas can vary based on the length and number of metering points in a network. In general, we expect losses from unaccounted for gas to be included as an expense in the same line item as other gas expenses. Reporting entities should also consider the impact unaccounted for gas may have on the recognition of unbilled revenue, inventory balances, and the level of certain fuel-related regulatory assets.

5.6 *Natural gas optimization agreements*

Figure 5-9 depicts a typical natural gas optimization agreement.

Figure 5-9
Typical natural gas optimization agreements



Reporting entities may enter into arrangements with third parties to manage their natural gas supply, transportation, storage, or any combination thereof. These arrangements are generally referred to as asset optimization agreements or natural gas optimization agreements. The terms of the agreements vary and each arrangement should be considered based on the specific facts and circumstances. In a typical natural gas optimization arrangement, the reporting entity (the shipper) transfers title to any combination of some or all of its natural gas supply, transportation, and storage contracts to a financial intermediary (the asset optimizer or optimizer). In some cases, the shipper retains full title to its underlying contracts. The optimizer is usually required to sell a specified supply of natural gas to the shipper in accordance with a predetermined schedule, although some agreements permit the natural gas to be called by the shipper when needed. During the contract period, the asset optimizer will trade the assets to maximize its return based on market price fluctuations.

In many respects, natural gas optimization agreements are similar to physical or virtual storage and park and loan transactions. Key characteristics of a natural gas optimization arrangement include:

- It is predetermined that the asset optimizer will trade the assets.
- The profits generated from the trading activity are shared with the shipper in the form of a monthly fee, a percentage of profits, or some combination thereof.

In this type of arrangement, the shipper benefits from a reduced cost of its natural gas supply and storage. It may retain these benefits, or in the case of a regulated utility, it may share them with its customers in the form of reduced rates.

In considering the accounting for a natural gas optimization agreement, the reporting entity needs to assess the overall natural gas optimization agreement (which provides the overall rights and obligations of the shipper and the optimizer), as well as any embedded forward or option agreements (e.g., the forward sale of natural gas supply from the optimizer to the shipper).

In evaluating this type of arrangement, the reporting entity should follow the commodity contract accounting framework discussed in UP 1. In some cases, one arrangement may include various components that are subject to different accounting models. Although the accounting will vary depending on facts and circumstances, lease accounting is usually not applicable unless the arrangement involves the right to use identified property, plant, or equipment (e.g., a storage facility). In addition, the contracts are usually not derivatives in their entirety. Because the natural gas optimization agreement contains multiple elements, including the trading of transportation and storage and the delivery of natural gas, these agreements typically do not meet the net settlement criterion.

However, an asset optimization contract may contain one or more embedded derivatives requiring separation. As described above, asset optimization agreements typically include forward and, at times, option contracts for the purchase of natural gas from the financial intermediary. These types of contracts would be derivatives on a stand-alone basis; therefore, further analysis is required to determine if they should be separated from the host contract. In accordance with ASC 815-15-25-1, an embedded derivative should be separated from its host contract and accounted for as a derivative if three criteria are met.

As summarized in Figure 5-10, asset optimization agreements typically include an embedded derivative instrument that should be recognized at fair value in the financial statements of the shipper; however, the terms and conditions of each arrangement should be evaluated. See UP 3.4 for further information on the evaluation of embedded derivatives.

Figure 5-10

Does an asset optimization agreement contain an embedded derivative that requires separation from the host?

Guidance	Evaluation	Comments
Economic characteristics of the embedded are not clearly and closely related to the host	Met	<ul style="list-style-type: none"> □ The host contract is determined based on the nonderivative elements; typically natural gas storage or capacity. □ The embedded elements (e.g., natural gas supply) are separate deliverables; they are generally not clearly and closely related to the host contract. □ See UP 3.4.3 for information on evaluating the clearly and closely related criterion.
Hybrid instrument is not remeasured at fair value under otherwise applicable US GAAP	Met	<ul style="list-style-type: none"> □ The asset optimization agreement is not remeasured at fair value.

Guidance	Evaluation	Comments
A separate instrument with the same terms as the embedded derivative would be a derivative instrument subject to ASC 815	Met	<ul style="list-style-type: none"> □ A firm commitment to receive natural gas in the future would generally meet the definition of derivative. □ The separated embedded derivative may be eligible for hedge accounting in some circumstances (see the response to Question 5-4).

EXAMPLE 5-5

Natural gas optimization of supply and transportation

On May 1, 20X1, Rosemary Electric & Gas Company (REG) enters into a natural gas optimization agreement for its natural gas supply and capacity with Big Bank. As a result, it transfers title to a natural gas supply arrangement for 10,000 MMBtus of natural gas and also assigns a related capacity agreement. Big Bank receives the initial delivery of natural gas directly from REG's supplier and is required to sell 10,000 MMBtus of natural gas to REG on December 1, 20X1 for \$5/MMBtu. In the interim, Big Bank can trade both the natural gas supply and natural gas capacity. REG receives an optimization fee of \$1,000 per month from Big Bank, regardless of the optimization activities. On December 1, 20X1, REG receives the natural gas from Big Bank.

For purposes of this example, the spot and forward prices of natural gas (forward price for delivery in December 20X1) are as follows (\$/MMBtu):

Date	Spot	Forward
May 1, 20X1	\$4.00	\$5.00
June 30, 20X1	3.00	4.50
September 30, 20X1	3.50	5.50
December 1, 20X1	6.00	—

How should REG account for the natural gas optimization agreement?

Analysis

The agreement does not contain a lease because there is no specified property, plant, or equipment. The arrangement does not meet the definition of a derivative in its entirety because of the lack of net settlement related to the pipeline capacity component of the agreement. However, the natural gas optimization agreement is a hybrid instrument comprising the host contract (the capacity agreement, which is a nonderivative component) and an embedded forward natural gas purchase agreement. The forward natural gas purchase agreement is not clearly and closely related to the host, so it should be separated and accounted for at fair value on a recurring basis. See the response to Question 5-6 for information on evaluating

whether the forward agreement can be accounted for as a normal purchases and normal sales contract.

REG would record the following journal entries to account for this agreement (amounts in thousands).

	Date	Journal entries	Cash	Fuel inventory	Derivative	Income statement
1	05/01	No accounting by REG for initial delivery of contracts to Big Bank (see note 1)				
2(a)	06/30	Record change in value of forward natural gas purchase (10,000 × (\$5.00 – \$4.50))			(\$5)	\$5
2(b)		Record optimization fee (\$1,000 × 2 months) (see note 2)	\$2			(2)
3(a)	09/30	Record change in value (10,000 × (\$4.50 – \$5.50))			10	(10)
3(b)		Record optimization fee (\$1,000 × 3 months) (see note 2)	3			(3)
4(a)	12/01	Record change in value (10,000 × (\$5.50 – \$6.00))			5	(5)
4(b)		Record delivery of natural gas from Big Bank and reversal of unrealized gains	(50)	50	(10)	10
4(c)		Record optimization fee (\$1,000 × 2 months) (see note 2)	2			(2)
TOTAL			(\$43)	\$50	\$ —	(\$ 7)

Note 1: This example assumes that the contracts were at the money at the time of transfer to Big Bank. The contract terms may be modified to include an initial receipt or payment of cash or other compensation if the contracts were in or out of the money at the time of transfer. In such case, additional journal entries would be required. See the response to Question 5-6 for information on the potential implications if the initial supply agreements were previously designated as normal purchases or normal sales.

Note 2: The optimization fee journal entry would be recorded on a monthly basis. To simplify this example, a cumulative entry is recorded on a quarterly basis.

The example includes only one receipt of natural gas from Big Bank on December 1, 20X1 and a simple profit sharing fee in the form of a monthly payment from Big Bank to REG. In practice, there may be different variations of the profit sharing (e.g., a split percentage of the profits once trading revenues reach a certain level). Furthermore, the shipper may receive natural gas supply, capacity, as well as storage rights at varying times over the arrangement.

Question 5-6

Can a reporting entity apply the normal purchases and normal sales scope exception to natural gas supply agreements that have been transferred into an asset optimization arrangement?

PwC response

No. As discussed in ASC 815-10-15-36, gross physical delivery in the normal course of business is required for a contract to qualify for the normal purchases and normal sales scope exception. Once a reporting entity transfers supply contracts to an asset optimizer, it no longer receives gross physical delivery of the natural gas under the original purchase agreement. Ultimately, the reporting entity will receive deliveries of natural gas from the asset optimizer, but it has suspended deliveries from its original supplier due to the optimization contract. In addition, because it will be sharing in profits through optimization fees for the trading activities associated with those supply contracts, the reporting entity has effectively net settled the contracts.

Furthermore, a transfer of natural gas supply arrangements that were previously designated under the normal purchases and normal sales scope exception into an asset optimization agreement will taint the contracts. This requires de-designation of the transferred contracts (as they were effectively net settled) and may also impact current and future similar contracts. See UP 3.3.1 for further information about tainting and the normal purchases and normal sales scope exception.

Chapter 6: ***Emission allowances***

6.1 Chapter overview

Utilities, power companies, and energy traders may buy, sell, and hold emission allowances to meet emissions requirements associated with generating electricity or to profit from market price changes. The term “emission allowance” refers to a tradeable instrument that conveys a right to emit a unit of pollution. This chapter provides interpretive guidance on accounting for the initial acquisition of emission allowances issued as part of U.S. federal, regional, and state programs. It also addresses emissions-related topics such as sales of allowances, impairment, and accounting for compliance. See UP 7 for information on accounting for renewable energy credits.

The accounting for emission allowances can be complex and is subject to judgment because of the lack of authoritative guidance. Both the FASB and IASB have previously attempted to address the topic. However, the FASB removed the project from its agenda in January 2014 and no guidance was issued. The IASB is still in the research phase of their project on emission allowances and have not provided a timeline for completion. Absent other guidance, emission allowances are accounted for using the guidance in ASC 330, *Inventory*, or ASC 350, *Intangibles*.

In addition, IAS 20, *Accounting for Government Grants and Disclosure of Government Assistance*, provides guidance on the initial measurement of nonmonetary grants and may be applied to emission allowance accounting. This guidance may be used by analogy for U.S. GAAP reporting due to the lack of specific U.S. GAAP authoritative guidance.

This chapter addresses the accounting and reporting of emission allowances. It includes details regarding the assessment of emission allowances as possible derivatives and the relevant guidance when assessing emission allowances for impairment.

6.2 Accounting models for emission allowances

Reporting entities use various models to account for emission allowances. The FASB has previously expressed its belief that the classification of emission allowances as intangible assets is preferable. In practice, utilities and power companies typically classify allowances as inventory (whether held for use or sale) or intangible assets (held for use). Absent authoritative guidance, we believe either classification is acceptable, provided the classification is applied consistently, is reasonable based on the intended use of the allowances, and is properly disclosed. However, we would generally not expect allowances held for sale to be classified as intangible assets because the activity of selling (i.e., goods held for sale in the ordinary course of business) is consistent with the definition of inventory. Therefore, a company that changes its policy would be required to demonstrate that the new classification is preferable based on their intended use, consistent with our discussion on renewable energy credits in UP 7.3. The accounting model applied will impact financial statement presentation and the impairment model used in subsequent accounting (see UP 6.5).

6.2.1 *Classification*

To determine how to classify emission allowances, reporting entities need to consider the definitions of inventory and intangible assets.

6.2.1.1 *Inventory*

ASC 330-10-20 defines inventory.

Partial definition from ASC 330-10-20

Inventory: The aggregate of those items of tangible personal property that have any of the following characteristics:

- a. Held for sale in the ordinary course of business
- b. In process of production for such sale
- c. To be currently consumed in the production of goods or services to be available for sale.

Some entities, such as trading organizations, may be engaged in buying and selling emission allowances in the normal course of business. Others, such as utilities or power companies, may use allowances to meet compliance requirements associated with the production of electricity. In both cases, the key elements of the inventory definition are met.

6.2.1.2 *Intangible assets*

Emission allowances held for use may also meet the definition of intangible assets provided by ASC 350.

Partial definition from ASC 350-10-20

Intangible Assets: Assets (not including financial assets) that lack physical substance.

Emission allowances evidence the authorization to pollute, based on the number of allowances that are allocated by a government entity or otherwise obtained. In addition, emission allowances lack physical substance. Emission allowances are not financial assets because cash is not delivered when they are used; instead, the emission allowance itself is delivered to demonstrate compliance with established regulations. Therefore, they meet the definition of an intangible asset.

Question 6-1

Is it acceptable to classify emission allowances as part of generation plant?

PwC response

Yes, but only in limited circumstances. As a result of prior acquisitions of emission allowances in a plant acquisition or business combination, some reporting entities may have recorded emission allowances as part of the overall property, plant, and equipment balance. Such presentation is acceptable for existing allowances, provided that management's intent is to use the emission allowances in production.

However, property, plant, and equipment generally consists of long-term assets used to create and distribute products and services of a reporting entity. Emission allowances facilitate a reporting entity's ability to satisfy emissions requirements related to the production of electricity and the allowances are not used in the physical generation of the electricity. Therefore, we believe the accounting for newly-acquired allowances should follow either an inventory or intangible asset model.

Emission allowances recorded as part of plant are depreciated over the useful life of the related plant asset.

Question 6-2

Does an emission allowance meet the definition of a derivative?

PwC response

No. An emission allowance itself does not meet the definition of a derivative because it does not contain an underlying. An underlying is a price or index that interacts with a notional amount in a contract to determine the settlement amount; an underlying is not the asset or liability itself. Therefore, an emission allowance itself does not contain an underlying and is not accounted for as a derivative.

However, as discussed in UP 6.3.2.1, contracts for the purchase or sale of emission allowances (e.g., forwards, futures, or options) may meet the definition of a derivative. In addition, as discussed in UP 6.6, a compliance obligation which requires a reporting entity to deliver emission allowances in the future may contain an embedded derivative.

6.3 Acquisition of emission allowances

The accounting for the acquisition of emission allowances varies depending on the source of the allowances. Allowances may be obtained through government allocation, bilateral agreements, or vintage year swaps. Specific considerations for accounting for emission allowances obtained through each of these sources follow.

6.3.1 Emission allowances acquired through government allocation

Utilities and power companies often obtain emission allowances through government allocation or distribution. Emission allowances that are awarded to a company from a governmental entity free of charge are a form of nonmonetary government grant. U.S. GAAP does not specify the accounting for government grants received by "for-profit"

entities. As a result, reporting entities that apply U.S. GAAP generally refer to IAS 20 when no other specific literature is on point.¹

IAS 20 provides guidance on the initial measurement of nonmonetary grants.

IAS 20.23

A government grant may take the form of a transfer of a non-monetary asset, such as land or other resources, for the use of the entity. In these circumstances it is usual to assess the fair value of the non-monetary asset and to account for both grant and asset at that fair value. An alternative course that is sometimes followed is to record both asset and grant at a nominal amount.

IAS 20 allows a reporting entity to make an accounting policy choice in the recognition and measurement of nonmonetary assets received in the form of a grant, such as emission allowances. Current practice in the utility and power industry is to assign no, or a nominal, value to allocated emission allowances. However, a reporting entity could alternatively record the emission allowances at fair value at inception with a corresponding deferred income amount. In accordance with IAS 20.24, the deferred income amount may be deducted from the related asset's carrying value or recorded as a separate obligation based on the guidance in IAS 20.12.

IAS 20.12

Government grants shall be recognized in profit or loss on a systematic basis over the periods in which the entity recognises as expenses the related costs for which the grants are intended to compensate.

IAS 20.15(b) highlights that grants are “rarely gratuitous” and are instead intended to compensate entities for a related cost. In the case of emission allowances, the initial grant compensates a reporting entity for the expected future expense associated with emissions. Therefore, the recognition of the asset received is offset by recording a related deferred income amount representing the related grant or compliance obligation.

Regardless of the method selected, a reporting entity should apply its accounting policy consistently. Example 6-1 illustrates the accounting for allocated emission allowances.

EXAMPLE 6-1

Accounting for emission allowances allocated free of charge

On January 1, 20X2, Rosemary Electric & Gas Company receives an allocation of 1,000 emission allowances from the local air quality management district. The

¹ A current list of Issues Papers of the Accounting Standards Division of the AICPA indicates that an October 1979 paper, *Accounting for Grants Received from Governments*, was considered superseded by IAS 20. For detailed guidance on certain aspects of accounting for government grants in accordance with IAS 20, see UP 16.

emission allowances have a five-year vintage and a fair market value of \$1 million as of the grant date. REG accounts for emission allowances as intangible assets and uses them to meet its compliance requirements for emissions due to generation. During each of 20X3 and 20X4, REG uses 200 allocated emission allowances to meet its generation-related compliance obligation. At the beginning of 20X5, REG identifies that it has excess emission allowances and sells its 600 remaining allowances for \$700,000.

How should REG account for the initial allocation of emission allowances and the subsequent sale?

Analysis

REG's accounting will depend on whether it initially records the allocated allowances at a nominal value or fair value.

Initial value—\$0

If REG assigns a value of \$0 to the allowances when allocated on January 1, 20X2, it records the following journal entries (amounts in thousands):

Year	Journal entries	Cash	Emission allowance asset	Contra expense (or other income)
1	Record receipt of emission allowances (number of allowances is maintained in REG's records, but assigned a \$0 value)	\$ —	\$ —	\$ —
1-2	No expense entries are recorded for compliance because the allowances have a \$0 basis	—	—	—
3	Record sale of emission allowances for \$700	700	—	(700)
TOTAL		\$700	\$ 0	(\$700)

Because REG is allocated enough emission allowances to cover its production, no liability or expense is recognized for its compliance obligation.

Initial value—fair value, net presentation

On day one, REG would record emission allowance assets of \$1 million, offset by deferred income of \$1 million (zero balance sheet impact). The remaining journal entries would be the same as under the nominal-value approach.

Initial value—fair value, gross presentation

If REG applies the fair value approach on a gross basis, the net impact on expense is the same as the nominal-value approach; however, the balance sheet would be "grossed up." The following journal entries would be recorded (amounts in thousands):

Year	Journal entries	Cash	Emission allowance asset	Deferred income	Contra expense (or other income)
1	Record receipt of emission allowances	\$ —	\$1,000	(\$1,000)	\$ —
1-2	Two years of expense (\$200 per year based on usage and initial carrying value); the asset is expensed and deferred income is recognized using the same pattern	—	(400)	400	—
3	Record sale of emission allowances for \$700	700	(600)	600	(700)
TOTAL		\$700	\$ 0	\$ 0	(\$700)

The use of the gross fair value method of recording emission allowances could potentially result in a different accounting impact compared with applying the two other methods if (1) the reporting entity subsequently determines that it does not have a probable liability for future emissions or (2) the amount of the liability changes. See UP 6.6 for further information on accounting for the compliance obligation.

6.3.2 *Emission allowances acquired through purchase*

Emission allowances that are purchased through a freestanding contract are typically recorded at the amount paid.

Allowances acquired in a business combination should be measured and recorded at fair value in accordance with ASC 805, *Business Combinations*.

6.3.2.1 *Forward contracts for emission allowances*

Reporting entities may enter into physically- or financially-settled forward contracts for emission allowances, as well as futures, options, or swaps. These transactions may be stand-alone agreements or embedded as part of a larger contract. Although emission allowances themselves are not derivatives under ASC 815, a forward contract for delivery of emission allowances may meet the definition of a derivative, as described in Figure 6-1.

Figure 6-1

Does a forward contract for emission allowances meet the definition of a derivative?

Criterion in ASC 815	Evaluation	Comments
Notional amount and underlying	Met	<input type="checkbox"/> Notional (quantity of allowances) and underlying (the price) are usually specified.

Criterion in ASC 815	Evaluation	Comments
No initial net investment	Met	<ul style="list-style-type: none"> □ No initial net investment is typically required. □ Option contracts involve premiums that should be assessed; however, standard option premiums that represent only the time value of money are not considered an initial net investment.
Net settlement	It depends	<ul style="list-style-type: none"> □ We would expect financially-settled forward contracts for emission allowances to meet the definition of a derivative. □ However, emission allowance contracts are usually physically settled; contractual net settlement is not typical but should be evaluated. □ Currently, market mechanisms for net settlement are limited but the readily-convertible-to-cash criterion may be met; markets should be evaluated and monitored.

In evaluating physically-settled contracts for emission allowances, the key question typically is whether the contract has the characteristic of net settlement, which can be achieved in one of three ways.

ASC 815-10-15-83(c)

Net settlement. The contract can be settled net by any of the following means:

1. Its terms implicitly or explicitly require or permit net settlement.
2. It can readily be settled net by a means outside the contract.
3. It provides for delivery of an asset that puts the recipient in a position not substantially different from net settlement.

Following are factors to consider in assessing whether a forward contract for emission allowances meets the net settlement criterion. See UP 3.2.3 for further information on overall application of the net settlement criterion.

- Net settlement under contract terms

When evaluating whether the net settlement criterion is met, a reporting entity should first consider whether the contract terms explicitly or implicitly provide for net settlement of the entire contract. Forward contracts for emission allowances typically require physical delivery of the allowance and do not permit explicit net settlement. However, the reporting entity should review the type of contract and

its terms to ensure net settlement is not allowed as implicit net settlement terms or liquidating damage provisions may imply that the contract could be net settled.

□ Net settlement through a market mechanism

In this form of net settlement, one of the parties is required to deliver an asset, but there is an established market mechanism that facilitates net settlement outside the contract. ASC 815-10-15-110 through 15-116 provides guidance on assessing whether an established market mechanism exists.

A key aspect of a market mechanism is that one of the parties to the agreement can be fully relieved of its rights and obligations under the contract. There are currently exchange-traded contracts for certain California emission allowances. Reporting entities should consider this exchange, if applicable, in making their contract assessment. Furthermore, the markets continually evolve (e.g., certain states are in the process of creating exchanges) and could increase the likelihood of a market mechanism existing as the allowances are transacted more frequently. Therefore, reporting entities should monitor this attribute on an ongoing basis.

□ Net settlement by delivery of an asset that is readily convertible to cash

Whether there is an active spot market for the particular product being sold under the contract is the key factor in assessing whether an asset is readily convertible to cash. The reporting entity should consider current market conditions in this analysis. To be deemed an active spot market, a market should have transactions with sufficient frequency and volume to provide pricing information that is readily available on an ongoing basis (i.e., quoted prices are readily available).

We have previously concluded that many physically settled forward contracts for emission allowances qualify as derivatives because they meet the readily-convertible-to-cash criterion. However, markets vary across the country. For example, environmental legislation proposed or enacted at the federal, regional, or state level may impact emissions trading activity. In addition, there may be no trading in some types of allowances, such as allowances issued by a specific county or air management district. See UP 3.2.3.3 for further information on the determination of whether a market is active.

A contract for emission allowances may be a derivative if it meets the net settlement criterion, depending on the type of contract and the related market. A reporting entity should evaluate all facts and circumstances in concluding on the appropriate accounting for a specific emission allowance contract and monitor its conclusion periodically because markets may evolve, potentially changing the accounting. Finally, if a contract is not a derivative in its entirety, a reporting entity should evaluate it to determine if there are any embedded derivatives that require separation.

Question 6-3

Are contracts for emission allowances that otherwise meet the definition of a derivative eligible for the normal purchases and normal sales scope exception?

PwC response

It depends. A forward purchase contract for emission allowances to be used to meet the reporting entity's compliance obligation for the expected generation of electricity could qualify for the normal purchases and normal sales scope exception, provided the reporting entity appropriately documents the election and the relevant criteria are met. Reporting entities should evaluate the nature of their contracts (e.g., will the reporting entity take delivery of the allowances, or is the contract going to net settle) and their intended use (e.g., are the allowances to be used for compliance or for trading) when determining whether the normal purchases and normal sales scope exception can be elected.

A reporting entity may also consider conditionally designating emission allowance contracts under the normal purchases and normal sales scope exception if physical delivery is probable throughout the life of the contract and the other criteria for application of this exception are met (in accordance with ASC 815-10-15-22 through 15-51, as applicable). If a conditionally-designated normal purchases and normal sales contract meets the definition of a derivative at a later date, such as when an emissions market becomes readily convertible to cash, the contract would not be accounted for as a derivative since it would meet the normal purchases and normal sales scope exception. Absent the normal purchases and normal sales designation, the reporting entity would be required to record the contract at its fair value at the time it becomes a derivative. See UP 3.3.1 for further information on the normal purchases and normal sales scope exception.

6.3.3 *Vintage year swaps*

Reporting entities may enter into exchanges of emission allowances (commonly referred to as "vintage year swaps"). In these transactions, entities exchange emission allowances relating to a certain vintage year for another vintage year. For example, a reporting entity may swap 1,300 allowances of vintage year 20X1 for 1,000 allowances of vintage year 20X2. The reporting entity may seek such a transaction if it anticipates a shortfall in a certain year, but expects to have excess allowances in another period.

In determining the appropriate accounting for vintage year swaps, reporting entities should consider the guidance for nonmonetary transactions provided by ASC 845, *Nonmonetary Transactions* (ASC 845).

ASC 845-10-25-1

A reciprocal transfer of a nonmonetary asset shall be deemed an exchange only if the transferor has no substantial continuing involvement in the transferred asset such that the usual risks and rewards of ownership of the asset are transferred.

Definition from ASC 845-10-20

Exchange: An exchange (or exchange transaction) is a reciprocal transfer between two entities that results in one of the entity's acquiring assets or services or satisfying liabilities by surrendering other assets or services or incurring other obligations.

Vintage year swaps typically meet the definition of a reciprocal exchange because the reporting entity gives up allowances from one vintage year (for which it will have no continuing involvement) in exchange for emission allowances from another vintage year.

ASC 845 requires qualifying nonmonetary exchange transactions to be accounted for based on the fair value of the assets exchanged (generally the fair value of the asset surrendered) unless certain conditions apply.

ASC 845-10-30-3

A nonmonetary exchange shall be measured based on the recorded amount (after reduction, if appropriate, for an indicated impairment of value as discussed in paragraph 360-10-40-4) of the nonmonetary asset(s) relinquished, and not on the fair values of the exchanged assets, if any of the following conditions apply:

- a. The fair value of neither the asset(s) received nor the asset(s) relinquished is determinable within reasonable limits.
- b. The transaction is an exchange of a product or property held for sale in the ordinary course of business for a product or property to be sold in the same line of business to facilitate sales to customers other than the parties to the exchange.
- c. The transaction lacks commercial substance (see [845-10-30-4]).

Reporting entities should consider the specific facts and circumstances surrounding any vintage year swaps in evaluating the appropriate accounting. However, in general, the application of the model may differ depending on whether the allowances are held for use or held for sale.

6.3.3.1 Held for use

As discussed in ASC 845-10-30-3, a nonmonetary exchange should be accounted for at fair value unless the transaction qualifies for certain specified exceptions. As summarized in Figure 6-2, we generally would not expect any of these exceptions to apply to emission allowances held for use.

Figure 6-2
Evaluating vintage year swaps of emission allowances held for use

Exception	Met?	Evaluation
Fair value is not determinable	No	There generally are quoted prices available for emission allowances.
Product held for sale in ordinary course of business; exchange to facilitate sales to other customers	No	Emission allowances held for use in operations are not held for sale in the ordinary course of business.
Lacks commercial substance	No	Because exchanges of emission allowances involve swaps between vintage years, it generally would be expected that there would be a significant change in the reporting entity's future cash flows as a result of the exchange, and thus the transaction has commercial substance.

Because the exceptions are not typically applicable, we generally would expect vintage year swaps of emission allowances to be recorded based on the fair value of the assets exchanged. As a result, a reporting entity exchanging emission allowances with a \$0 cost basis and fair value in excess of \$0 will record a gain at the time of the transaction.

6.3.3.2 *Held for sale*

The evaluation of vintage year swaps of emission allowances held for sale generally follows the same model in UP 6.3.3.1 for swaps of allowances held for use. However, there may be limited circumstances when vintage year swaps of emission allowances held for sale may qualify for the exception in ASC 845-10-30-3(b) for exchanges that facilitate sales to customers other than the parties to the exchange, and the exchange would be recognized at the recorded amount of the emission allowances relinquished, without any gain or loss recognized.

One example may be when a reporting entity enters into a forward sale of emission allowances relating to a vintage year that it does not already hold in inventory. The reporting entity may seek to enter into a separate transaction to purchase the shortfall of allowances in exchange for excess inventory relating to another vintage year. Such a transaction would allow the reporting entity to complete its original forward sale transaction.

6.3.3.3 *Considerations for regulated utilities*

If a regulated utility realizes a gain or loss on a vintage year swap, it should evaluate the applicability of regulatory accounting. A regulated utility should consider its current rate recovery mechanism for emission allowance costs, as well as any specific rate orders relating to emission allowances or vintage year swaps, as applicable, to

determine whether it is appropriate to record a regulatory liability (for a gain) or regulatory asset (for a loss) instead of recognizing an immediate gain or loss.

6.4 Sales of emission allowances

A reporting entity that sells emission allowances will need to determine when to recognize revenue and how to determine the related expense when accounting for it under an executory contract model.

6.4.1 Revenue recognition

Any time a reporting entity enters into a contract for the sale of emission allowances, it should assess whether the contract meets the definition of a derivative. See UP 6.3.2.1 for information on factors to consider in the assessment. Contracts that meet the definition of a derivative should be accounted for following the guidance in ASC 815.

If the sale is accounted for as an executory contract because it does not meet the definition of a derivative, revenue is typically recognized when title to the emission allowances is transferred to the counterparty.

Question 6-4

If the reporting entity sells emission allowances that it could otherwise use to meet a compliance obligation, should it defer recognition of any gain on sale?

PwC response

Generally, no. Reporting entities sometimes sell emission allowances even though the allowances could be used to meet a compliance requirement. In that circumstance, a question arises as to whether it is appropriate to defer any gain on sale as an offset to future expense associated with a potential purchase obligation to meet the compliance requirement. As discussed in UP 6.6, the compliance obligation should be accounted for separately from any emission allowances held by the reporting entity. If there are no contingencies and there is no continuing involvement associated with the sale, reporting entities should not defer gains received on the sale or exchange (such as from vintage year swaps) of emission allowances.

However, if the reporting entity had planned to use the allowances to meet its compliance obligation, the sale could result in an increase in this obligation (as a result of the need to buy allowances from the market), thus potentially offsetting the gain on sale. See UP 6.6 for further information on measuring an emission allowance compliance liability.

6.4.2 Expense recognition

A reporting entity should recognize emission allowance expense at the time of recognition of the related sale. Emission allowances held for sale generally should be accounted for as inventory. As such, the reporting entity should apply an appropriate

inventory costing model (e.g., specific identification; weighted average cost; first-in, first-out) to determine the appropriate expense.

Question 6-5

How should a reporting entity calculate the expense for allowances sold if it follows an intangible model for emission allowances?

PwC response

As discussed in UP 6.2.1, we would generally expect a reporting entity to account for emission allowances held for sale as inventory. However, in some circumstances, if a reporting entity sells emission allowances accounted for as intangible assets, we believe it should follow an expense model similar to that used for emission allowances classified as inventory. The cost of emission allowances recorded as intangible assets should be recorded as an expense when sold.

In addition, for those emission allowances a reporting entity classifies as intangible assets and uses for compliance, the cost should be allocated against the compliance liability at the time they are used or surrendered (see UP 6.6).

6.5 ***Impairment***

Impairment considerations for emission allowances can be complicated by environmental and carbon legislation proposed or enacted at the federal, regional, or state level. For example, significant developments in recent years include the Environmental Protection Agency's successor to the Clean Air Interstate Rule, which governs emissions of sulfur dioxide and nitrogen oxide, as well as the Cross-State Air Pollution Rule (CSAPR). Phase 1 implementation of CSAPR is scheduled for 2015 and Phase 2 beginning in 2017. In addition, new rules governing power plant emissions continue to be proposed. Such developments illustrate the continued evolution of the regulatory landscape that could impact the value of emission allowances. Ongoing legislative developments regarding emissions could also trigger the need for impairment evaluations for utility plant.

Measurement of potential impairment of emission allowances may require significant judgment, depending on the availability of transparent forward pricing information. Furthermore, the impairment model varies, depending on how the emission allowances are classified.

6.5.1 ***Inventory***

Impairment of emission allowances classified as inventory is based on a lower-of-cost-or-market model. See UP 11.2 for further information on lower-of-cost-or-market considerations for inventory.

6.5.2 ***Intangible assets***

In accordance with ASC 350-30-35-14, emission allowances classified as intangible assets should be reviewed for impairment based on the guidance provided by ASC

360. Any impairment measurements would also be performed in accordance with ASC 360. This guidance requires evaluation of impairment in response to events or changes in circumstances that suggest the carrying value may not be recoverable. Impairment indicators include:

- A significant decline in the price of emission allowances
- An adverse change in the manner in which the reporting entity's generating assets are used, impacting the possible usage of the allowances (e.g., resulting from a change in the fuel mix)
- A significant adverse change in the business or regulatory environment, such as a regulatory action requiring that a plant be shut down

If an impairment evaluation is triggered, the reporting entity should perform the analysis based on facts and circumstances existing at the balance sheet date. Changes in value subsequent to the balance sheet date would be incorporated in any impairment analysis performed in the subsequent period.

6.5.3 *Plant*

Emission allowances classified as part of plant also should be evaluated for impairment in accordance with the requirements of ASC 360. Triggering events are similar to those described in UP 6.5.2 for emission allowances classified as intangible assets. However, when considering a significant decline in prices or adverse changes, the evaluation should be performed at the level of the plant asset or asset group (rather than simply for emission allowances on their own). ASC 360 defines asset group as follows.

Definition from ASC 360-10-20

Asset Group: An asset group is the unit of accounting for a long-lived asset or assets to be held and used, which represents the lowest level for which identifiable cash flows are largely independent of the cash flows of other groups of assets and liabilities.

The definition notes that the asset group is based on the lowest level of identifiable cash flows. In the case of emission allowances held as part of the overall plant balance, the emission allowances will be included in a broader asset group for impairment (such as the plant or potentially a group of plants, depending on operations and other entity-specific factors). Emission allowances classified as part of plant would not be tested for impairment on a stand-alone basis. Because impairment is considered in the context of the entire plant balance, a decline in the market value of the emission allowances alone generally would not trigger a potential impairment of either the emission allowances or the plant. See UP 12.5 for further information on evaluating asset groupings for power plants in the context of an impairment evaluation.

Consistent with the approach for intangible assets discussed in UP 6.5.2, the reporting entity should perform the analysis based on facts and circumstances existing at the

balance sheet date. Subsequent changes in value would be incorporated in any related subsequent period impairment analysis.

Question 6-6

Should emission allowances that are classified as intangible assets be included in an impairment analysis of plant?

PwC response

It depends. Whether emission allowances classified as intangible assets are included in a plant impairment analysis will depend on whether the allowances are part of the asset group. In accordance with ASC 360-10-35-17, an impairment charge should be recognized if the carrying value of a long-lived asset group is not recoverable and exceeds its fair value.

We believe emission allowances should be included in the asset group for a specified plant if the allowances are required for operation of the plant and were obtained for that purpose. Furthermore, if it is determined that an impairment charge is required, the charge should be allocated among the long-lived assets in the asset group, including emission allowances classified as intangible assets. Any other assets in the group should be tested for impairment in accordance with other applicable guidance.

However, if the allowances are intended for the broader compliance obligation of the reporting entity, it should not include the allowances in the asset group. If the plant is expected to need emission allowances for its operations, the expense considered as part of the cash flows in a long-lived asset impairment test would be determined based on market prices.

See BC 10.4.1.3, Example 3, and BC 10.4.1.5 for further information.

6.6 Compliance with emission allowance programs

When subject to an emission allowance program, a reporting entity is obligated to surrender a certain number of emission allowances at the end of a compliance period, with the number surrendered generally based on emissions during the period. A reporting entity may not always have sufficient emission allowances to cover emissions from planned generation and could face penalties from the government or other regulatory body if its actual emissions exceed allowances held. A reporting entity can avoid penalties by purchasing more allowances or redirecting its source of supply (e.g., generating from another plant).

There is currently diversity in practice with respect to accounting for an emissions compliance obligation. In evaluating the appropriate accounting, a reporting entity should first consider whether its obligation to deliver emission allowances in the future (1) represents a derivative in its entirety or (2) contains an embedded derivative that should be separated from the host contract and accounted for at fair value. If the

obligation does not contain an embedded derivative, the reporting entity should develop a recognition approach that is supportable under U.S. GAAP.

6.6.1 *Evaluate whether the obligation contains an embedded derivative*

Although an emission allowance obligation would not meet the definition of a derivative under ASC 815 in its entirety (because it represents an obligation equal to the value of the allowances at the time the emissions occur), it may include an embedded derivative for the forward delivery of emission allowances due but not yet surrendered.

Considerations in determining whether the obligation includes an embedded derivative that should be separated from the host contract are summarized in Figure 6-3.

Figure 6-3

Does an emissions compliance obligation contain an embedded derivative that requires separation?

Criterion in ASC 815	Evaluation	Comments
Economic characteristics of the embedded are not clearly and closely related to the host	Met	<ul style="list-style-type: none"> □ The host contract is a liability for emissions compliance (i.e., a debt host). □ Changes in the price of emission allowances are not clearly and closely related to a debt host instrument.
Hybrid instrument is not remeasured at fair value under otherwise applicable U.S. GAAP	Met	<ul style="list-style-type: none"> □ Although some of the measurement techniques used to measure a compliance obligation are similar to a fair value measurement, the obligation is not a fair value measurement.
A separate instrument with the same terms as the embedded derivative would be a derivative instrument subject to ASC 815	It depends	<ul style="list-style-type: none"> □ A firm commitment to receive or deliver emission allowances in the future may meet the definition of a derivative (see UP 6.3.2.1).

The third criterion, whether a stand-alone contract requiring future delivery of the specified emission allowances would meet the definition of a derivative, is the one that typically requires judgment. As discussed in UP 6.3.2.1, some contracts for delivery of emission allowances meet the definition of a derivative because they have (1) an underlying, (2) no initial net investment, and (3) the characteristic of net settlement. A contract for delivery of emission allowances may net settle under its contract terms or due to a market mechanism or spot market. This analysis is specific to the contract terms and market, and the result will vary depending on the type of emission

allowance. Similarly, the reporting entity should assess the potential embedded derivative to determine if it has the characteristic of net settlement. For example, the jurisdiction may permit settlement in cash based on the value of the allowances at the settlement date, or the emission allowances to be delivered may be readily convertible to cash.

If the reporting entity concludes that the emissions allowance compliance obligation contains an embedded derivative, it should initially separate the embedded feature by recording the obligation to deliver the allowances at fair value and adjust it each period based on changes in market prices.

If a reporting entity applies ASC 980 and concludes that emission allowance compliance costs qualify for deferral under a regulatory mechanism, it should also defer unrealized gains and losses related to the embedded derivative. See UP Question 17-4. Furthermore, the amounts recorded would be subject to the fair value and derivatives disclosure requirements. These are addressed in FSP 19 and 20 and UP 21.

Question 6-7

If an emission allowance obligation contains an embedded derivative, is the derivative eligible for the normal purchases and normal sales scope exception?

PwC response

It depends. ASC 815-10-15-22 defines normal purchases and normal sales.

ASC 815-10-15-22

Normal purchases and normal sales are contracts that provide for the purchase or sale of something other than a financial instrument or derivative instrument that will be delivered in quantities expected to be used or sold by the reporting entity over a reasonable period in the normal course of business.

In general, a compliance obligation related to emissions will be settled through the physical delivery of emission allowance certificates. In such cases, we would generally expect the obligation to be eligible for the normal purchases and normal sales scope exception if all of the criteria are met (see ASC 815-10-15-22 through 15-51, as applicable). However, in many cases, even if the delivery obligation is designated as normal, it will still be measured using current market pricing or a technique similar to fair value (see UP 6.6.2 for further discussion). As such, we generally believe that valuing the obligation following an embedded derivative model when an emissions obligation contains an embedded derivative, may be an appropriate representation of the entities obligation.

6.6.2 Apply another measurement technique

If the obligation does not contain an embedded derivative, the reporting entity should measure the emissions obligation using another relevant measurement technique. Two acceptable methods are summarized in Figure 6-4.

Figure 6-4
Methods for recognizing expense associated with emission allowance compliance

Method	Considerations
Accrue as you go	<ul style="list-style-type: none"> □ Expense is recognized as the obligation arises; expense is based on fair value, cost, or another rational method □ Results in better matching of the expense with the related emissions □ Emissions held are offset against the compliance obligation when they are surrendered, relieving the asset and the related liability
Accrue when a shortfall occurs	<ul style="list-style-type: none"> □ Emission allowances are expensed as used; any shortfall is accrued when it occurs □ May result in uneven expense recognition throughout the year

A reporting entity should evaluate its facts and circumstances in determining which approach to follow and should be able to support its recognition policy within U.S. GAAP. The policy adopted should be applied consistently. In addition, the reporting entity should recognize any potential penalties or fines when probable and estimable, consistent with the guidance in ASC 450, *Contingencies*. Considerations in applying the two methods of recognition are as follows.

6.6.2.1 Accrue as you go

Due to the nature of an emissions compliance obligation, we generally believe that a related liability should be accrued as a period expense as power is generated (i.e., as the emissions occur and the obligation arises). Different approaches are acceptable for measurement of the liability, including:

- Fair value or market price of emission allowances (because the liability could be settled by purchasing allowances from the market). If this approach is used, we believe the amounts recorded would be subject to the fair value disclosure requirements in FSP 20
- Weighted-average cost of allowances (whether classified as inventory or intangible assets)
- Cost of allowances to be purchased in existing forward contractual arrangements

Under this method, compliance expense is recognized based on the reporting entity's measurement methodology. Allowances held and recorded as inventory or intangible assets are offset against the compliance liability when the allowances are surrendered to demonstrate compliance. The reporting entity would recognize any difference between the liability and the carrying value of the allowances as a gain or loss when the obligation is settled.

In some cases, a combination of these approaches or another method of measurement may be appropriate, depending on the nature of the emission program requirements and the expected settlement amount. A reporting entity should evaluate its facts and circumstances and apply a consistent approach to measure the liability.

6.6.2.2 *Accrue when a shortfall occurs*

Under this method, a reporting entity expenses its allowances held as the obligation arises and no separate compliance obligation is recorded. The amount of expense recognized will depend on whether the allowances were allocated by the government (\$0 cost basis) or purchased. The reporting entity will accrue a liability for inadequate allowances only at the time actual emission levels are in excess of emission allowances held for a particular vintage year. For example, under this approach, if a reporting entity holds sufficient emission allowances to offset its expected emissions for the first three quarters of a given fiscal year, it would not record a liability until its actual emission levels exceed allowances held (i.e., in the fourth quarter, assuming such excess emissions materialize).

This approach requires careful tracking of both the expected emission levels and the emission allowances held. In addition, management and legal counsel should review contractual commitments and an inventory of emission allowances held to determine whether and when to record obligations for emissions. This approach may also lead to an expense recognition pattern that backloads expense, even though the reporting entity's actual emission levels may have been constant throughout the year.

Chapter 7:
Renewable energy credits

7.1 Chapter overview

Renewable portfolio standards (RPS) obligate retail sellers of electricity (e.g., regulated utilities and direct access suppliers) to obtain a certain percentage or amount of their power supply from renewable energy sources. In most states, RPS requirements may be met by obtaining renewable energy credits (RECs) that provide evidence that power has been generated by a qualifying renewable resource, although states may have alternative methods of demonstrating compliance.

Terms analogous to RECs include alternative energy credits, renewable energy certificates, green tags, tradable renewable certificates, and renewable energy attributes. Although the terminology for RECs varies, ultimately, each program requires similar accounting considerations. The term RECs has been used throughout this guide to refer to all similar products.

To assist reporting entities in accounting for their REC activities, this chapter is organized as follows:

Accounting policy: Inventory versus intangible asset	UP 7.3.1
Accounting policy: Classification of RECs as output	UP 7.3.2
Generation of RECs	UP 7.4
REC sales	UP 7.5
REC purchases	UP 7.6

Reporting entities subject to RPS requirements should also address the accounting for compliance (see UP 7.7).

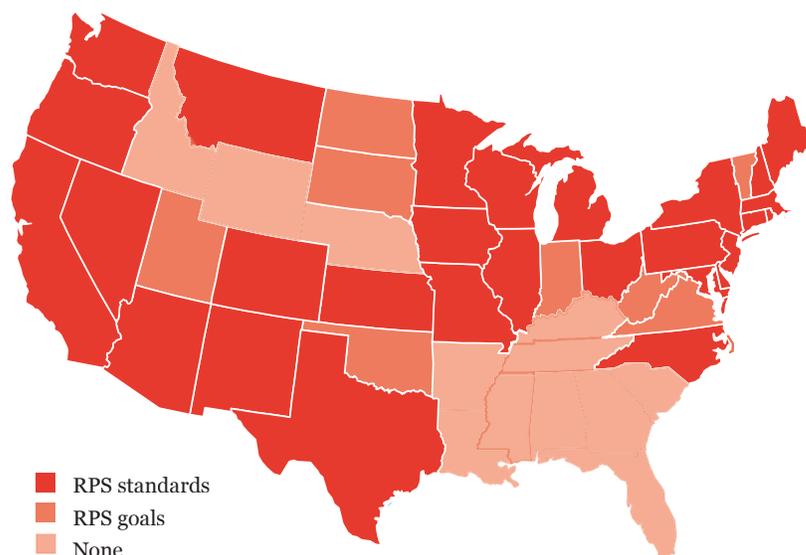
The accounting for RECs is an evolving area and, similar to emission allowances, there is no authoritative guidance on RECs within U.S. GAAP. The FASB's most recent project on accounting for emission trading schemes was also intended to address the accounting for RECs. However, the project was removed from the FASB's agenda and no guidance was issued.

7.2 RPS programs

RPS program goals often include environmental improvement, increased diversity and security of energy supply, reduced volatility in power prices (given the absence of significant fuel costs), and local economic development.

Renewable requirements are typically established at a local level or on a state-by-state basis by a regulatory commission, state legislature, or other governing body. Twenty-nine states and the District of Columbia have mandatory RPS, while eight states have renewable energy goals. There is currently no federal RPS standard. Figure 7-1 illustrates the current status of RPS requirements by state:

Figure 7-1
Renewable portfolio standards requirements by state



Source: Database of State Incentives for Renewables & Efficiency (a project of the N.C. Solar Center at N.C. State University and of The Interstate Renewable Energy Council), March 2013 (www.dsireusa.org). Note: Hawaii (not pictured) has an RPS standard.

States develop their RPS programs individually. Although there are some similarities in certain jurisdictions, most programs are unique to each specific state. Each RPS mandate has its own parameters, rules, and requirements, especially with respect to qualifying generation sources, renewable resource goals (usually expressed as a percentage of total load), and target dates for compliance:

□ *Allowable generation*

Wind, solar, and biomass are accepted sources in all states that have an RPS requirement, while certain states also include energy-efficiency measures as an allowable source. Examples of other sources include ocean thermal and tidal energy in California and New York, advanced nuclear and carbon capture and sequestration in Ohio, waste tire in Nevada, and anaerobic digestion in North Carolina.

□ *Resource goals*

Many states have established initial minimum renewable energy targets with the requirement increasing over time. Most states have set goals between 15 percent and 20 percent, although some states have higher targets (such as Hawaii at 40 percent). In addition, certain states have defined a megawatt-hour goal in lieu of a percentage, or a combination of percentage and megawatt-hours. Some states also establish goals for specified types of renewable sources. For example, New Jersey has specified targets for solar and offshore wind power sources. In some states, goals vary between utilities within a jurisdiction or are based on the size of a utility or type of utility (municipal vs. investor owned).

- *Penalties for noncompliance*

Some states have mandated penalties for noncompliance. For example, Washington has a penalty of \$50/MWh shortfall (adjusted annually for inflation), while other states have discretionary penalties. Penalties are typically not recoverable from customers.

- *Target dates*

Most states mandated 2010 or earlier as an initial implementation date for some minimum level of compliance, while 2020 or 2025 are often targeted as the dates for complying with the ultimate goal.

Renewable energy credits provide evidence of the generation of electricity from a qualifying renewable facility. Because qualifications vary, RECs may be accepted for purposes of compliance in one state but not another.

The outputs from a qualifying renewable facility provide the same benefit to the off-taker as production from a traditional plant, except that the government has incentivized certain parties to pay more for power from renewable energy sources. The REC is issued by the government to assist in demonstrating compliance with RPS requirements and is a mechanism that has been created to certify that energy (the actual output) was produced by a qualifying facility.

Typically, one REC is created for every megawatt-hour of energy produced from a qualifying facility. A reporting entity may generate RECs for its own compliance with RPS requirements, or may generate them for sale.

7.3 Accounting for renewable energy credits

The creation, sale, and use of RECs results in a number of challenging accounting issues including contract accounting, revenue recognition, and cost allocation. The issues that may arise and the accounting outcome will depend on whether the reporting entity is generating, selling, or buying RECs. Further, as part of the initial accounting for RECs, the reporting entity should make two key accounting policy elections:

- Are RECs inventory or intangibles?
- Are RECs considered output?

A change in a reporting entity's view on either of these policies would be considered a change in accounting method, which would be accounted for as a change in accounting principle in accordance with ASC 250, *Accounting Change and Error Corrections*. To adopt a change in method, a reporting entity would have to conclude that the new method is preferable. To determine the appropriate accounting, we recommend that reporting entities first assess these accounting policy elections based on their specific facts and circumstances and then consider the guidance related to the applicable activity (i.e., generation, sales, or purchases).

7.3.1 **Key policy decision one: are renewable energy credits inventory or intangibles?**

Reporting entities use various models to account for RECs. In practice, utilities and power companies typically classify RECs as (1) inventory (whether held for use or sale) or (2) intangible assets (held for use). We believe either classification is acceptable, provided the classification is applied consistently, is reasonable based on the intended use of the RECs, and is properly disclosed. There is one exception: we would generally not expect RECs held for sale to be classified as intangible assets because the activity of selling (i.e., goods held for sale in the ordinary course of business) is consistent with the definition of inventory, not intangible assets.

7.3.1.1 **Inventory**

ASC 330-10-20 defines inventory.

Partial definition from ASC 330-10-20

Inventory: The aggregate of those items of tangible personal property that have any of the following characteristics:

- a. Held for sale in the ordinary course of business
- b. In process of production for such sale
- c. To be currently consumed in the production of goods or services to be available for sale.

Owners of renewable energy facilities may generate and hold RECs for sale. Other entities, such as trading organizations, may engage in buying and selling RECs in the normal course of business. Furthermore, some reporting entities may purchase RECs to comply with RPS requirements. In each of these cases, the key elements of the inventory definition are met.

7.3.1.2 **Intangible assets**

RECs held for use may also meet the definition of intangible assets in ASC 350.

Partial definition from ASC 350-10-20

Intangible Assets: Assets (not including financial assets) that lack physical substance.

RECs evidence the generation of energy from a qualifying resource. In addition, RECs lack physical substance. RECs are not financial assets because cash is not delivered; instead, the REC itself is delivered for compliance with the related RPS program. Therefore, the definition of an intangible asset is met.

RECs would be considered to have a finite life and would be subject to amortization as they are typically claimed or retired in a short period of time to meet their local RPS requirements.

Question 7-1

Do RECs meet the definition of a derivative?

PwC response

No. RECs themselves do not meet the definition of a derivative because they do not contain an underlying. An underlying is a price or index that interacts with a notional amount in a contract to determine the settlement amount; an underlying is not the asset or liability itself. Therefore, a REC does not contain an underlying and is not accounted for as a derivative.

In addition, as discussed in UP 7.5.1.2, absent contractual net settlement, physical forward contracts for the purchase or sale of RECs generally do not meet the definition of a derivative, although this conclusion could change as markets evolve.

7.3.1.3 Impairment

A reporting entity's policy on accounting for RECs either as inventory or intangible assets will impact how it considers impairment.

Inventory

Impairment of RECs classified as inventory is based on the lower-of-cost-or-market model. See UP 11.2 for further information on lower-of-cost-or-market considerations for inventory.

Intangible assets

In accordance with ASC 350-30-35-14, RECs classified as intangible assets subject to amortization should be reviewed for impairment based on the guidance provided by ASC 360, *Property, Plant, and Equipment (ASC 360)*. Any impairment measurements would also be performed in accordance with ASC 360. This guidance requires evaluation of impairment in response to events or changes in circumstances that suggest the carrying value may not be recoverable. Impairment indicators include:

- A significant decline in the price of RECs
- A significant change in the business or regulatory environment, such as regulatory actions or other changes impacting the need for RECs (e.g., softening or delay in mandates or expansion of allowable technologies)

If an impairment evaluation is triggered, the reporting entity should perform the analysis based on facts and circumstances existing at the balance sheet date. The reporting entity would incorporate changes in value subsequent to the balance sheet date in any impairment analysis performed in the subsequent period.

7.3.2 Key policy decision two: are renewable energy credits output?

Because the generation of power is integral to the creation of RECs, a question arises as to whether RECs are considered part of the output from a generating plant. There are two views about whether RECs are considered output. A reporting entity's conclusion on whether RECs are output will potentially impact cost allocation, revenue recognition, and whether a contract contains a lease. In summary, the two views are as follows:

□ *View A: RECs are output*

Proponents of View A believe that RECs should be considered an output from the facility where they originate. They argue that the construction of a facility and the pricing inherent in the contractual arrangements with off-takers are based on the combined benefit of energy, capacity, RECs, and any other products from the facility. View A proponents point to the fact that each of these outputs is dependent on production at the specified facility and conclude that all products sold from the specific facility are output.

□ *View B: RECs are a government incentive*

Proponents of View B believe that RECs should not be considered an output. They believe that "output" is limited to the productive capacity of a specified property and relates only to those products that require "steel in the ground" (e.g., energy, capacity). Supporters of this view state that RECs do not arise as a result of the physical attributes of the property, but rather are a paper product from a government program (similar to tax incentives) created to promote the construction of renewable energy facilities.

The two views can be contrasted in that View A proponents view RECs as products created through production: an outflow. View B proponents view RECs as a benefit provided by the government to promote green energy: a benefit or inflow that conceptually is no different from the cash payments received for production. The two views are summarized in Figure 7-2.

Figure 7-2
Should renewable energy credits be considered output?

View	Summary	Support
RECs are output from a facility	The utility of a renewable energy property is embodied in the environmental attributes it produces. RECs are dependent on a specified facility and are integral to the full utility/economics of the property.	<ul style="list-style-type: none"> □ RECs are consistent with the definition of "output" in ASC 805. □ Significant economics related to a renewable power plant are embodied in the RECs. □ RECs are dependent on a specified facility.

View	Summary	Support
RECs are a government incentive	RECs are intangibles that are not physically “produced or generated”; instead RECs are issued by a regulatory oversight body. RECs are a government incentive intended to further a public policy objective.	<ul style="list-style-type: none"> □ All power plants produce (generally) the same outputs: energy, capacity, and ancillary services. RECs are a government incentive and represent an inflow or form of payment for renewable production. □ “Output” from the facility is limited to physical production; RECs lack physical substance.

7.3.2.1 View A: renewable energy credits are output

Those who subscribe to View A believe that output has a broader scope than simply physical production from a specified property. Rather, the concept of output extends to any utility or benefit directly attributable to the use of the asset. Supporters of View A believe the following factors contribute to the conclusion that RECs are output from a facility.

Definition of output

The definition of output included in ASC 805 provides relevant guidance.

ASC 805-10-55-4(c)

Output. The results of inputs and processes applied to those inputs that provide or have the ability to provide a return in the form of dividends, lower costs, or other economic benefits directly to investors or other owners, members, or participants.

RECs are an economic benefit obtained through the operation of a specified renewable energy facility. RECs are created by the production output of the facility (i.e., if the generation facility does not produce power, RECs are not created). The generation of renewable energy by a qualifying plant produces the right to a credit, which directly identifies with output of that specified asset. Once a generation unit is certified under a renewable energy program, the owner (operator) may sell the RECs generated through production, and those RECs are viewed as part of the utility of that plant. The sale of the RECs may be to the offtaker of the power generated or to another third party, depending on the terms of the power purchase agreement.

Economic considerations

Historically, the cost of constructing a renewable energy facility was recovered through an above-market price for power sold from the facility (effectively, the renewable energy premium was embedded in the contract price). However, the growth of RPS requirements and the need for a mechanism to track compliance led to the creation of RECs. It also divided pricing among all products from a facility, including energy, capacity, and RECs. Today, power from a renewable facility may be

sold as “brown” or “dirty” power without the RECs attached; the brown power price is based on market prices of power in general and no premium is paid for the power itself. The RECs may be sold with the power (green power) or separately, and are separately priced. Green power sells for a premium, representing the value of the RECs.

As a result of these changes, the economics of a renewable energy facility are now based on the sale of capacity, energy, and RECs as individual units. The sale of brown power and capacity alone does not typically cover the cost of construction and fixed carrying costs of a renewable facility. The ability to realize income from the sale of RECs—which may be substantial—is a significant contributor to the economics of a renewable facility. RECs are usually the primary motivator for building specified renewable property (other forms of generation are typically more efficient and economic for the production of energy alone).

Therefore, because RECs represent a substantial portion of the economics of a renewable plant, View A proponents believe it is inconsistent to exclude their economic value from the determination of the accounting for contractual arrangements. That is, they believe that the economics of RECs are integral to the plant itself and thus to exclude them from an evaluation as output would be to ignore their economics.

The lease literature similarly provides useful guidance on the concept of output in the context of a discussion on economic control. Specifically, the criteria in ASC 840-10-15-6 are based on a concept that *the right to use* the property is conveyed through *control* of the property. Proponents of View A believe that control may be obtained through physical, operational, or economic control of the specified property. ASC 840-10-55-34 suggests that an arrangement whereby one party covers the fixed carrying costs of the plant provides evidence that it is remote that another entity will take more than a minor amount of the output, indicating that the arrangement is a lease (i.e., that economic control is conveyed).

ASC 840-10-55-34

All evidence should be considered when making the assessment as to the possibility that other parties will take more than a minor amount of the output, including evidence provided by the arrangement’s pricing. For example, if an arrangement’s pricing provides for a fixed capacity charge designed to recover the supplier’s capital investment in the subject property, plant, or equipment, the pricing may be persuasive evidence that it is remote that parties other than the purchaser will take more than a minor amount of the output or other *utility* that will be produced or generated by the property, plant, or equipment.

Considering this excerpt in the context of a renewable plant, the fact that energy and capacity payments are not sufficient to cover the fixed costs suggests that another party (the REC off-taker) is taking more than a minor amount of the utility of the property. The “utility” taken by the REC purchaser is in the form of an intangible produced by the specified property and represents an economic output of the facility.

Specified property

RECs are specific to a qualifying facility, and in a typical plant-specific arrangement the owner of the property has no obligation to deliver RECs other than those produced by the property (i.e., no replacement right or obligation) unless there is a performance guarantee. The REC off-taker is exposed to the risk of weather or other variables that may impact production; therefore, the off-taker is not economically indifferent to the source of the RECs. Instead, those RECs represent an economic benefit provided by a specific property and would be considered output of that property.

The concept of specified property is further addressed in the lease literature and is also relevant to the evaluation of whether RECs are output more broadly. ASC 840-10-15-8 states that agreements that transfer the right to use specified property, plant, or equipment meet the definition of a lease. ASC 840-10-15-10 through 15-14 provide additional guidance to determine whether an arrangement does not qualify for lease accounting because the property is not specified. Consistent with this guidance, the generation of RECs is not generic but is instead attached to operation of a specific property. As such, proponents of this view believe the RECs are an output of the property.

7.3.2.2 *View B: renewable energy credits are a government incentive*

View B proponents focus on the fact that RECs are assets created under various government programs to incentivize green power production. Therefore, RECs are a government subsidy, similar to a tax incentive, intended to further a public policy objective. As such, RECs are not facility outputs. Because RECs are a government incentive, View B supporters believe that the accounting for RECs should follow the historical treatment of tax incentives, which are not an “output” from the facility.

Similarities with tax incentives

Supporters of View B believe that RECs are a government incentive, similar to grants, investment tax credits, production tax credits (PTCs), and other forms of renewable energy incentives, which are provided by the government to encourage the construction of renewable power plants. There are similarities and differences between RECs and PTCs.

Similar to RECs, PTCs are created and allocated to owners of qualifying facilities for each unit of production (only during the first 10 years of operation, compared with RECs, which are ongoing).

The two primary differences between PTCs and RECs are:

- Transferability—RECs are transferable, while PTCs and ITCs are available only to the tax owner of the facility. Utilities and retail service providers use RECs to satisfy their compliance obligations. RECs can be held for future use, sold after they are earned, or transferred to another party, and have value. As a result, bilateral markets have developed for the sale of RECs, and some states are trying to increase the liquidity of the REC markets.

- Source of funding—In the case of tax incentives, the government pays the owner of the facility directly. RECs are purchased by companies for trading, compliance obligations, or other purposes.

Proponents of View B do not believe that the differences should result in an accounting distinction for RECs. The fact that the RECs can be traded or sold and that funding comes from third parties does not change the fundamental nature of RECs as a form of payment/incentive for the production of green energy. REC programs are intended to compensate the owner/operator for the additional costs associated with a green power facility. As such, under this view, RECs are no different than tax incentives or other forms of consideration conveyed for the production of energy and treatment as an output is inconsistent with practice for tax incentives.

Renewable energy credits lack physical substance

Although View B supporters acknowledge that RECs are associated with a specified generating facility, they do not believe that RECs are an output or utility produced by the property. They believe there is no difference between the outputs from a renewable energy facility and a fossil-fuel or nuclear facility: all of these power plants provide capacity to support the system, energy for supply to customers, ancillary services, and, in some cases, steam or heat. Proponents of this view focus on the fundamental nature of RECs and the fact that they are not physically produced or generated. Renewable power plants provide no additional tangible benefit, and RECs are a piece of paper or electronic certificate that may provide economic benefit but lack physical substance. Although the value of the REC relates to the underlying plant, the REC is effectively a government subsidy of the production of green power. Based on this, View B supporters believe that they cannot be considered an output.

7.3.2.3 Conclusion

We believe both views have merit and there is support for each of the positions. Therefore, we believe that the determination of whether RECs are output is an accounting policy election. However, although View B has been broadly vetted and accepted, we understand that the SEC staff has not reached a conclusion on View A.

The accounting policy election should be applied consistently, assuming reasonably similar facts and circumstances, and should also be disclosed. Furthermore, as this accounting policy election is based on a reporting entity's perspective on the underlying nature of RECs (output or government incentive), we believe that this accounting policy election should be applied consistently within a consolidated entity.

A change in a reporting entity's view on whether RECs are output would be considered a change in accounting method, which would be accounted for as a change in accounting principle in accordance with ASC 250, *Accounting Change and Error Corrections*. To adopt a change in method, a reporting entity would have to conclude that the new method is preferable.

Question 7-2

Does the determination of whether RECs are output impact the classification of RECs as inventory or intangible assets?

PwC response

No. We believe the determination of whether RECs are output is separate from the determination of whether RECs should be classified as inventory or intangible assets. As discussed in UP 7.3.1, the balance sheet classification of RECs is primarily based on the reporting entity's intended use: RECs held for sale are generally classified as inventory while RECs held for use may be classified as inventory or intangible assets. In contrast, the evaluation of whether RECs are output is based on a reporting entity's fundamental view of a REC as a product produced by the plant versus a government incentive. We believe that these are separate determinations because one is focused on the generation or creation of RECs (output assessment) while the other is predicated on their subsequent use (inventory versus intangible asset).

7.4 Generation of renewable energy credits

The accounting for RECs begins at the time they are generated. Whether a reporting entity generates RECs for its own compliance or for sale, it will need to determine whether it should allocate costs of production to RECs produced. Whether costs are allocated generally depends on whether RECs are deemed output, as highlighted in Figure 7-3:

Figure 7-3

Cost allocation for generated renewable energy credits

Output?	Intended purpose	Type of sale	Evaluation of determining cost
Yes	Held for use	Not applicable	A rational costing approach should be used to allocate costs to RECs.
	Held for sale	Included as part of lease of the facility	Not applicable. RECs included in an overall lease of a facility do not require any separate accounting. The owner of the plant is selling use of the facility, not RECs.
		Executory contract or no current contract (held in inventory)	Allocate cost to RECs using rational costing approach; allocation may not be necessary if REC revenue is recognized at the time power is sold (see UP 7.5.3).
No	Held for use or sale	All	No cost is allocated to generated RECs.

If RECs are accounted for as output, the reporting entity should generally allocate costs of production to the RECs, unless the RECs are part of the lease of the facility (see UP 7.5 for discussion of RECs sold as part of a facility lease). That cost becomes the carrying value for the REC when it is used or sold. From a practical perspective, cost allocation may not be necessary when the REC sale occurs simultaneously with the sale of energy.

If the reporting entity's accounting policy is that RECs are not output, it will not allocate any costs to the RECs. In this case, the RECs are viewed as a government incentive and there is no cost of production. In such cases, the reporting entity should track its RECs, but the carrying value will be zero.

7.4.1 Cost allocation

Unless the plant is leased, reporting entities should allocate costs from the production process costs to RECs accounted for as output, irrespective of the balance sheet classification of RECs as inventory or intangible assets. Considerations with respect to RECs classified as inventory and intangible assets follow.

7.4.1.1 Inventory

ASC 330-10-30-1 states the following:

Excerpt from ASC 330-10-30-1

Cost means in principle the sum of the applicable expenditures and charges directly or indirectly incurred in bringing an article to its existing condition and location.

A portion of the cost of generation should be allocated to RECs in inventory. Consistent with physical inventory costing methods, allocable expenditures include depreciation and operating and maintenance expenses. The remaining cost of generation should be expensed as part of the production cost of power.

See PwC's ARM 3800 and ARM 3805 for further information on inventory costing.

7.4.1.2 Intangible assets

The guidance on accounting for the cost of internally-developed intangible assets, other than internal-use software or website development costs, is limited. We believe there are two views: (1) expense as incurred or (2) allocate the costs. The reporting entity should consistently apply its policy selected.

The general guidance on developing intangible assets indicates that costs should be expensed as incurred:

ASC 350-30-25-3

Costs of internally developing, maintaining, or restoring intangible assets that are not specifically identifiable, that have indeterminate lives, or that are inherent in a continuing business or nonprofit activity and related to an entity as a whole, shall be recognized as an expense when incurred.

Therefore, when RECs are classified as intangible assets and are generated, it would generally be appropriate for a reporting entity to expense the costs.

RECs accounted for as output

RECs are specifically-identifiable assets, usually with a specific vintage, that do not relate to a reporting entity as a whole. Rather, RECs are tradable units that can be used to demonstrate compliance with RPS requirements, or may be sold to a third party. Therefore, when RECs are accounted for as output, we believe it is appropriate to capitalize a portion of the production cost to RECs. The allocation methodology should be rational, and we would generally expect an approach similar to that applied to RECs classified as inventory.

7.4.1.3 *RECs produced for sale and not held in inventory*

As illustrated in Figure 7-3, if the power plant is leased to a third party and the RECs are considered output, the lessee is paying for the use of the facility, not for the individual outputs of the facility. In such cases, the selling entity should record lease revenue and no cost allocation for RECs will be applicable. However, if a reporting entity accounts for RECs as output and sells those RECs outside of a lease arrangement, it will need to allocate costs.

In certain situations, revenue from the sale of RECs will be recognized concurrently with the sale of energy, ancillary products, and other outputs from the facility (see UP 7.5.4 for further information on timing of revenue recognition). No cost allocation will be necessary because all costs will be recognized at the time of generation. However, if revenue from the sale of RECs is not recognized concurrently with the sale of energy, or RECs are held for sale at a future date, reporting entities should allocate costs.

7.5 *Renewable energy credits sales*

A reporting entity engaged in the sale of RECs will need to determine how and when to recognize revenue related to the REC sales. In addition, it will need to consider the related expense recognition. To make those determinations, a seller of RECs should consider (1) its accounting policy regarding RECs as output and (2) the form of arrangement used to sell the RECs (whether the RECs are being sold on a stand-alone basis through a forward contract or in combination with energy or other products).

Any time RECs are sold, a reporting entity should first apply the commodity contract accounting framework (see UP 1). Once the contract model is established, the reporting entity will need to consider the terms of its contractual arrangements and the specific requirements of the applicable RPS program to determine how and when

to recognize revenue. Finally, the reporting entity should consider the method by which expense is recorded related to the RECs sold.

After identifying the contract deliverables and unit of accounting, the parties should first determine whether the agreement contains a lease. If lease accounting does not apply, the contract should then be assessed to determine if it is a derivative in its entirety. The reporting entity should then assess whether it includes one or more embedded derivatives (unless the contract is a derivative in its entirety). If neither lease nor derivative accounting apply, the parties would account for the REC agreement as an executory contract (i.e., on an accrual basis).

7.5.1 Accounting for stand-alone forward renewable energy credit contracts

In some jurisdictions, reporting entities may satisfy their RPS requirements by purchasing RECs on a stand-alone basis. The ability to separate a REC from the associated energy allows for the creation of a tradable unit that can be purchased and sold without the physical constraints of a power market. Financially-settled forward contracts for RECs, as well as options or swaps involving RECs, generally meet the definition of a derivative and such contracts are not further discussed herein. In contrast, we discuss the accounting for physically-settled forward contracts for RECs in 7.5.1.2.

7.5.1.1 Lease accounting

If the reporting entity accounts for RECs as output, a contract for the purchase of RECs that is sourced from a specified power plant could qualify as a lease. However, because power plants also produce other outputs such as power and capacity, it is unlikely that the RECs alone would represent 90 percent of the total value of a plant's outputs. As such, this type of contract is generally not expected to meet the definition of a lease.

7.5.1.2 Derivative accounting

If the contract does not contain a lease, a reporting entity should next assess whether it is a derivative in its entirety.

Figure 7-4 highlights the evaluation of a typical forward contract for the physical purchase or sale of RECs.

Figure 7-4
Does a REC forward contract meet the definition of a derivative?

Guidance	Evaluation	Comments
Notional amount and underlying	Met	<input type="checkbox"/> Notional (quantity of RECs) and underlying (the price of the RECs) are usually specified.
Initial net investment	Met	<input type="checkbox"/> No initial net investment is typically required.

Guidance	Evaluation	Comments
Net settlement	Generally not met	<ul style="list-style-type: none"> □ Contracts for RECs are usually physically-settled; implicit net settlement is not typical but should be evaluated. □ Currently, we are not aware of a market mechanism for net settlement or active markets for spot sales of RECs; however, markets should be monitored as they evolve.

REC forward contracts that are physically settled generally will not meet the definition of a derivative instrument; however, each contract should be evaluated in the context of its individual facts and circumstances. In general, we would not expect a physically settled contract for RECs to be accounted for as a derivative because they fail the net settlement criterion.

ASC 815-10-15-83(c)

Net settlement. The contract can be settled net by any of the following means:

1. Its terms implicitly or explicitly require or permit net settlement.
2. It can readily be settled net by a means outside the contract.
3. It provides for delivery of an asset that puts the recipient in a position not substantially different from net settlement.

Following are factors to consider in assessing whether REC forward contracts meet the net settlement criterion. See UP 3.2.3 for further information on the overall application of the net settlement criterion.

- *Net settlement under contract terms*

When evaluating whether the net settlement criterion is met, a reporting entity should first consider whether the contract explicitly or implicitly provides for net settlement of the entire contract. Forward contracts for RECs typically require physical delivery and do not permit explicit net settlement. However, reporting entities should evaluate the type of contract and its terms to determine that there are no implicit net settlement terms or liquidating damage provisions that may imply that the contract could be net settled.

- *Net settlement through a market mechanism*

In this form of net settlement, one of the parties is required to deliver an asset, but there is an established market mechanism that facilitates net settlement outside the contract. ASC 815-10-15-110 through 15-116 provide guidance on indicators to consider in assessing whether an established market mechanism exists. A key aspect of a market mechanism is that one of the parties to the agreement can be fully relieved of its rights and obligations under the contract. We are not aware of

any markets for RECs in the United States in which a provider has the ability to be relieved of its full rights and obligations under a previously-executed contract.

- *Net settlement by delivery of an asset that is readily convertible to cash*

The key factor in assessing whether an asset is readily convertible to cash is whether there is an active spot market for the particular product being sold under the contract. Current market conditions should always be considered in this analysis. To be deemed an active market, a market must have transactions with sufficient frequency and volume to provide pricing information on an ongoing basis. In addition, quoted prices from that market will be readily available on an ongoing basis. See UP 3.2.3.3 for further information on the determination of whether a market is active. Based on the current structure of the markets, we are not aware of any active spot markets for RECs in the United States.

Based on these observations, we believe that derivative accounting is generally not applicable to these physically-settled forward contracts. However, a reporting entity should evaluate all facts and circumstances in concluding on the appropriate accounting for a specific REC contract and monitor its conclusion periodically because markets evolve, potentially rendering this type of contract a derivative.

In addition, if the contract does not meet the definition of a derivative in its entirety, the reporting entity should evaluate the contract to determine if there are any embedded derivatives that require separation.

Conditionally designating REC contracts as normal purchases and normal sales

Reporting entities may also consider conditionally designating REC contracts under the normal purchases and normal sales scope exception if physical delivery is probable throughout the life of the contract and the other criteria for application of this exception are met (ASC 815-10-15-22 through 15-51, as applicable).

If a conditionally-designated normal purchases and normal sales contract meets the definition of a derivative at a later date, it would be accounted for as a normal purchases and normal sales contract (i.e., not as a derivative) from the time the contract becomes a derivative, provided the reporting entity appropriately documents the election and the relevant criteria are met. Absent such a designation, the reporting entity would be required to record the contract at its fair value at the time it becomes a derivative. See UP 3.3.1 for further information on the normal purchases and normal sales scope exception.

7.5.1.3 *Executory contract accounting*

We would generally expect a stand-alone REC contract to be accounted for as an executory contract. In such cases, reporting entities should evaluate whether there are any embedded derivatives (e.g., pricing mechanisms) that require separation from the host contract (see UP 3.4 for information on evaluating embedded derivatives).

7.5.2 *Accounting for the forward sale or purchase of renewable energy credits within a power purchase agreement*

It is common for RECs to be sold within a power purchase agreement that includes other elements such as energy and capacity. Similar to a stand-alone contract for RECs, these contracts should be evaluated under the commodity contract accounting framework. After the reporting entity determines the appropriate accounting model(s), it will need to consider the allocation of the revenue or cost among lease, derivative, and other elements, as applicable.

7.5.2.1 *Lease accounting*

ASC 840 provides guidance for determining whether an agreement that transfers the right to use identified property, plant, or equipment should be accounted for as a lease. An arrangement contains a lease if both of the following conditions are met:

- Fulfillment of the arrangement is dependent on the use of specified property, plant, or equipment
- The arrangement conveys the right to control use of the property, plant, or equipment

These criteria consider whether the purchaser has the right or ability to control the property, plant, or equipment, including whether it is remote that one or more parties other than the purchaser will take more than a minor amount of output or other utility from the property, plant, or equipment. In general, a contract for a sale of substantially all of the energy, capacity, and RECs from a specified facility to a single party will contain a lease.

Energy and renewable energy credits sold to separate parties

In some situations, a reporting entity may sell energy and capacity from a specified property to one off-taker while retaining the RECs or selling them to a different counterparty. In such cases, the contract for the sale of RECs should be evaluated consistent with the lease discussion.

A reporting entity's policy on RECs as output may impact the lease evaluation. For example, if the reporting entity accounts for RECs as output, then sales of the RECs to one party and the energy and capacity to another may result in a conclusion that the arrangement does not contain a lease because the RECs represent more than a minor amount of the plants total output going to a different party. However, if the reporting entity's policy is that RECs are not output, the contract for energy and capacity may contain a lease.

7.5.2.2 *Derivative accounting*

If a reporting entity concludes that a contract for the sale of energy and RECs is not a lease, it should then assess whether the contract is a derivative in its entirety. Typically, this type of combined contract does not meet the definition of a derivative in its entirety because it lacks the net settlement criterion. Further, the reporting

entity would then evaluate whether the contract contains an embedded derivative that requires separation.

As discussed in UP 7.5.1.2, based on our understanding of current markets in the United States, the REC portion of the contract usually will not qualify as a derivative (absent contractual net settlement provisions). However, the reporting entity should evaluate the sale of energy, capacity, and other products (as applicable) to determine if the contract contains any embedded derivatives that require separation. See UP 3.4.3 for further information on evaluating these types of contracts.

7.5.3 *Allocation of consideration*

The recognition of revenue for a REC contract is determined by the conclusion as to whether it is accounted for as part of the overall lease of a facility or following an executory contract accounting model. Figure 7-5 summarizes potential revenue recognition models for RECs.

Figure 7-5
Seller considerations in renewable energy credit revenue allocation and recognition

Type of sale	Output?	Evaluation
Contract contains a lease	Yes	□ RECs are part of the lease of the facility, therefore payments received are part of lease revenue.
	No	□ RECs are accounted for following an executory contract model; see below.
Executory contract	Either	□ RECs are accounted for following an executory contract model; other contractual elements should follow the applicable model (derivative or executory contract). □ Reporting entities should consider timing of revenue recognition for the sale of RECs.

As noted in Figure 7-5, in general, revenue should be allocated to RECs and separately recognized in all cases, except when RECs are considered output and are sold as part of a lease.

7.5.3.1 *Renewable energy credits sold as part of a lease*

When RECs are part of the output of a facility and that facility is leased to another entity, the RECs are part of the overall usage of the facility. In such cases, the reporting entity is leasing its facility, and the lessee is using the facility to generate electric energy and RECs (generation activities may be performed by the reporting entity on the lessee's behalf if the reporting entity is the operator of the facility). Therefore, the reporting entity should not separately allocate revenue for the sale of RECs. Instead, the sale of RECs is part of the overall lease. Because lease accounting is applicable, the timing of revenue recognition should follow the appropriate lease

accounting guidance, considering factors such as potential levelization of lease payments and the classification of the lease.

If, however, the reporting entity's policy is that RECs are not output, then the sale of RECs is not part of the lease of the facility. Instead, that portion of the contract represents a nonlease element. The reporting entity should apply the lease accounting guidance to allocate consideration received between the lease and nonlease elements of the contract (as discussed in UP 2.3). The reporting entity should then apply an executory accounting model for the sale of RECs, including consideration of the appropriate timing of revenue recognition.

7.5.3.2 *Renewable energy credits sold as part of a contract that is not a lease*

When RECs are sold as part of a contract that contains other components (such as energy) and the contract does not contain a lease, a reporting entity should follow an executory accounting model for the sale of RECs (assuming the REC sale does not meet the definition of a derivative). In performing the allocation of consideration under an executory contract model, reporting entities should consider ASC 605-25, which provides guidance for multiple-element arrangements. In addition, reporting entities should consider the appropriate timing for revenue recognition (see UP 7.5.4.1).

The same revenue recognition considerations also would be applied to a stand-alone contract for the sale of RECs.

7.5.4 *Revenue recognition*

When a reporting entity determines that the sale of RECs should be accounted for following an executory contract model, it should consider the timing of revenue recognition. In many cases, the administration of the RPS or REC program is performed by the regional transmission organization, or some other organization on behalf of the state government or public utility commission. The administrator will typically track serial or reference numbers of RECs generated and remitted and hold accounts for each participant in the program.

As a first step in the process, a facility is typically certified as an eligible renewable energy resource, which allows the owner of that facility to participate in the state's or region's renewable energy program, as applicable. In most cases, a certified power generator will submit meter data to the program administrator upon generation of electricity. The generator typically has a legal right to a REC upon generation of power from the certified source; however, the RECs will not be received until after the administrator completes its settlement process. This normally involves a reconciliation of meter data in a manner consistent with the local market settlement system as well as other validation as required in that market. RECs awarded to the generator are specifically identified and credited to its account once the settlement process has been completed; there is typically a delay between the time the associated power is generated and the time the REC settlement process is complete.

Each jurisdiction operates a slightly different program, and the time between generation of the associated power and receipt of the REC can vary. For example, in

certain regions, RECs are credited on a monthly basis, while in others the REC is credited to the generator's account in the month following the quarter the power was generated. In addition, some regions allow automatic transfer of RECs from the generating entity to the purchasing entity, while other administrators require the generator to manually transfer the RECs each period.

7.5.4.1 *Timing of revenue recognition*

The timing of recognizing revenue will be dependent on whether the criteria has been met under the applicable guidance. The current criteria to be considered is discussed below; however, this evaluation should follow the accounting guidance that is effective when the transaction takes place. This evaluation may change when the new revenue standard (ASC 606) is effective for the reporting entity.

ASC 605 provides guidance on the appropriate timing for revenue recognition when lease and derivative accounting is not applicable.

Excerpt from ASC 605-10-S99-1

SAB Topic 13.A.1, Revenue Recognition—General

The staff believes that revenue generally is realized or realizable and earned when all of the following criteria are met:

- Persuasive evidence of an arrangement exists,
- Delivery has occurred or services have been rendered,
- The seller's price to the buyer is fixed or determinable, and
- Collectibility is reasonably assured.

In the typical transaction for the sale of RECs, there is persuasive evidence of an arrangement (i.e., a contractual arrangement such as a power purchase agreement), the seller's price to the buyer is fixed per REC, and collectibility is reasonably assured (subject to default risk in the normal course). However, in a combined sale of energy and RECs, the physical REC certificate will usually be delivered sometime after the electricity has been generated. Delivery of the REC will follow the applicable administration and reconciliation process. As such, it is important to consider the method and timing of delivery in determining when revenue should be recognized.

Whether delivery of a REC has occurred will depend in part on the manner in which the relevant RPS program operates. In some cases, the delivery of the power and related REC are separate, with the REC being delivered sometime after the power has been generated. For example, some power purchase agreements state that title to the REC will transfer upon delivery of the REC into the account of the buyer (which does not occur until completion of the administration and reconciliation process described above).

In other cases, the risks and rewards of ownership may be transferred simultaneous with the generation of power. In those circumstances, assuming all other revenue recognition criteria have been satisfied, a reporting entity may conclude that delivery of the RECs has occurred and that revenue can be recognized for both power and RECs at the time the power is generated.

In reaching a conclusion about the appropriate timing of revenue recognition, a reporting entity should evaluate specific contractual arrangements for the sale of RECs and the conditions of the relevant state or local program. Figure 7-6 highlights key factors to consider.

Figure 7-6

Determining when revenue should be recognized for the sale of renewable energy credits

Indicators that revenue should be recognized when RECs are transferred	Indicators that revenue should be recognized when power is generated
<ul style="list-style-type: none"> □ The contractual arrangement states that title does not transfer until the REC is deposited in the buyer's account □ An administrative/reconciliation process must be completed with the REC program administrator □ The seller is obligated to transfer the RECs only once the administrative/reconciliation process is complete □ The buyer is entitled to a full or partial refund if the seller fails to complete certain activities prior to depositing the RECs in the buyer's account 	<ul style="list-style-type: none"> □ There is automatic transfer of the RECs to the buyer's account (seller performs no activities after the time of generation) □ Language in the contract states that title to all environmental attributes, including RECs, transfers at the time of generation

Each state will have different parameters, depending on the program.¹ For example, California and Texas have programs that could lead to different accounting results, as indicated in the following examples.

EXAMPLE 7-1

Accounting for renewable energy credit sales in California

California's state renewable energy program is known as the Renewable Portfolio Standard (RPS). The mechanism for administering the RPS' recognized renewable energy certificates (RECs) is known as Western Renewable Energy Generation

¹ For information about RPS and REC programs in states, see the Database of State Incentives for Renewables and Efficiency at www.dsireusa.org.

Information System (WREGIS). Any entity that wishes to own RECs must register with the WREGIS administrator to establish an account. Account holders may register a generating unit (a renewable energy facility) and designate an active subaccount into which RECs will initially be deposited. After a generating unit reports generation for a given month, RECs are created for each megawatt-hour of renewable energy and assigned a unique serial number, which could also be in a batch. The RECs are created in the generating unit's assigned active subaccount within the generating unit owner's account. The RECs may be deposited directly into the off-taker's account via a forward certificate transfer, or transferred monthly via a one-time transfer.

Ivy Power Producers (IPP) enters into an agreement to deliver all of the energy, capacity, and RECs from its Wisteria Wind Power Project, a 40 MW wind facility, to Rosemary Electric & Gas Company (REG). The Wisteria Wind facility is located within the Western Interconnection, which is covered by WREGIS. Assume that IPP has an accounting policy that RECs are not output. Under the terms of the agreement between IPP and REG, IPP is required to designate REG as the transferee of a forward certificate transfer, such that the RECs generated by Wisteria will be automatically deposited in REG's account. In addition, the contract specifies that REG has ownership of all environmental attributes at the time of generation, including RECs and any other benefits.

When should IPP recognize revenue related to the sale of the RECs to REG?

Analysis

Under the contract terms, performance is completed and delivery occurs at the time the power is generated and delivered. In addition, title to the environmental attributes transfers at the time of generation and IPP has fulfilled the requirements of the contract by pre-certifying the plant and designating REG as the recipient.

IPP should be able to reliably calculate the number of RECs generated in a given period and would have fulfilled all of the contract terms at the time of generation. Therefore, in this case, it would be appropriate for IPP to recognize revenue for the sale of RECs under the contract at the time power is generated.

EXAMPLE 7-2

Accounting for renewable energy credit sales in Texas

The Renewable Energy Credit Program in Texas is administered by the Electric Reliability Council of Texas. ERCOT will post the exact RPS requirements for each participant on March 1 of the year following the year in question. For example, a participant will know exactly what its RPS requirements for 2014 are on March 1, 2015. The participant then has until March 31 to comply with that requirement. Participants may submit RECs in March from their Texas REC Program account in satisfaction of their requirement. However, the actual transfer of the RECs cannot occur until the RECs are allocated into the participant's account. RECs are not credited to the account of the generator until after meter data has been supplied to ERCOT and a reconciliation has been completed (this typically occurs at least 59 days after the end of each quarter).

Ivy Power Producers (IPP) enters into an agreement to sell all of the energy, capacity, and RECs from its Willow Wind Power Project, a 100 MW wind facility, to Rosemary Electric & Gas Company (REG). The Willow Wind project is located within ERCOT. Assume that IPP has an accounting policy that RECs are not output. Under the terms of the agreement between IPP and REG, IPP is required to deposit all RECs generated by the Willow project in REG's account once received from the state.

When should IPP recognize revenue related to the sale of the RECs to REG?

Analysis

IPP should not recognize revenue until delivery of the RECs into REG's account. The act of transferring the RECs to the purchaser has not been completed at the time of generation. Until credited to the purchaser's account, the RECs cannot be used by the purchaser.

7.5.5 Expense recognition

Reporting entities selling RECs need to consider expense recognition. Expense recognition for reporting entities selling RECs is applicable when the following circumstances are all present:

- RECs are accounted for as output (as discussed in UP 7.4.1, costs of generating RECs are allocated to RECs accounted for as output)
- Sale of RECs follows an executory contract model (not lease or derivative)
- Recognition of REC revenue occurs later than recognition of revenue from the energy and other products produced by the plant

If all of these conditions are present, the reporting entity should recognize REC expense at the time of recognition of the related REC sale. In other circumstances, cost allocation is not applicable (e.g., RECs are not output) or not meaningful (e.g., REC revenue is recognized at the same time as the related power revenue). See Figure 7-3 for a summary of fact patterns when cost allocation would be applicable.

In addition, RECs generated for sale are generally accounted for as inventory. As such, the reporting entity should adopt an appropriate inventory model (e.g., specific identification, weighted-average cost, or first-in, first-out) for expense recognition. See UP 7.4.1 and UP 7.6 for further information on allocating costs to RECs at the time of generation or purchase, respectively.

7.5.5.1 Expense recognition for RECs classified as intangible assets

The cost of RECs that a reporting entity classifies as intangible assets and uses for compliance should be allocated against the compliance liability at the time they are surrendered.

In addition, as discussed in UP 7.3.1, we would generally expect a reporting entity to account for RECs held for sale as inventory. However, in some circumstances, a

reporting entity may sell a REC that was accounted for as an intangible asset. In such cases, we believe that the reporting entity should follow an expense model similar to that used for RECs classified as inventory. The cost of RECs classified as intangible assets should be recorded as an expense when sold.

Question 7-3

When should the cost of RECs be recognized if they are held for trading purposes?

PwC response

If a reporting entity purchases and sells RECs (i.e., in a trading capacity), it will have a cost basis in its REC inventory because the cost of purchasing RECs should always be recognized, regardless of whether RECs are deemed output. Therefore, in a trading scenario, assuming that an executory contract model is applied, the cost of the REC should be recognized in the income statement at the time the related revenue for the sales is recognized.

7.6 ***REC purchases***

Reporting entities may purchase RECs to comply with RPS requirements or for resale. In all cases, the reporting entity will need to determine the appropriate cost basis for the RECs; neither the classification of RECs as inventory or intangibles nor the policy of whether RECs are output impacts this requirement.

The determination of the appropriate basis for purchased RECs may be straightforward when RECs are purchased in a stand-alone agreement: the cost basis is the purchase price. However, the determination of the cost of RECs can become more complex when RECs are purchased in a contract with other products or services. In such cases, the first step is to determine the appropriate accounting for each of the deliverables in the contract. See UP 7.5.2 for information on applying the commodity contract accounting framework to contracts containing RECs.

After identifying the appropriate accounting models, the reporting entity should follow the applicable allocation methodologies. Key considerations in allocating costs to RECs are summarized in Figure 7-7. See UP 1 for further information on the overall cost allocation models.

Figure 7-7

Cost allocation for purchased renewable energy credits

Type of purchase	Output?	Evaluation
Included as part of lease of a facility	Yes	Allocate lease consideration among energy, RECs, and other products produced by the plant

Type of purchase	Output?	Evaluation
Included as part of lease of a facility	No	Allocate contract consideration between lease and nonlease elements; RECs are a nonlease element of the contract
Included as part of a multiple-deliverable contract containing an embedded derivative for the forward purchase of energy	Either	Allocate consideration using hybrid instrument guidance in ASC 815-15-30-4 for non-option embedded derivatives
Executory contract	Either	Allocate cost to RECs using multiple-element guidance in ASC 605-25

As noted in Figure 7-7, costs should always be allocated to purchased RECs, irrespective of a reporting entity's policy on RECs as output, because it is paying for the RECs. However, the method of allocating the contractual cash flows may differ depending on the type of contract (i.e., lease, derivative, or executory contract). See also Question 7-4 regarding expense recognition related to RPS liabilities based on REC purchases.

The method by which costs are allocated to RECs generally should be established at the inception of the contract, although this may vary depending on the accounting model applied:

- Contract contains a lease—method of allocation should be established at lease inception
- Contract contains a derivative—method of allocation should be established at contract inception; pricing should be allocated to the derivative component such that the fair value is initially zero (for non-option derivatives)
- Entire contract is accounted for as an executory contract—method of allocation should be established at contract inception using the guidance in ASC 605

Although a contract containing multiple deliverables may separately price the RECs, a reporting entity should estimate the REC cost based on available market information, including the market price of RECs and green power, where available.

7.6.1 Application examples

The following examples are provided to illustrate the allocation of costs to purchased RECs.

EXAMPLE 7-3**Allocation of costs—bundled contract for energy and RECs, energy is not a derivative**

Rosemary Electric & Gas Company (REG) enters into a five-year forward contract with Ivy Power Producers (IPP) for the purchase of 50 percent of the energy and RECs from the Wisteria Wind Power Project. REG determines that the contract does not contain a lease. Furthermore, because there is no notional, the contract does not contain a derivative for the energy component. Therefore, the entire contract will be accounted for as an executory contract.

The contract specifies that the selling price of the energy is \$80/MWh and the RECs are \$30/REC.

How should REG allocate the total contract consideration between energy and RECs?

Analysis

REG should determine the fair value of each of the products sold and then allocate the total contract consideration based on the relative fair value of the deliverables. Although the price of each REC is specified, REG should not automatically allocate costs based on the contract amounts. These amounts may not necessarily represent the fair value of the two products provided.

EXAMPLE 7-4**Allocation of costs—bundled contract for energy and RECs, energy is a derivative**

Assume the same facts as in Example 7-3, except that in this case the contract specifies a fixed quantity per period. REG concludes that the energy portion of the contract should be accounted for as a derivative. The contract price is \$110/MWh and the average forward price for energy is \$80 at inception. In addition, REG concludes that the REC portion of the contract is not a derivative because the REC sales do not meet the net settlement criterion.

How should REG allocate the total contract consideration between energy and RECs?

Analysis

ASC 815-15-30-4 requires that an embedded forward contract that is a derivative and separated from its host contract should be initially recorded at fair value (i.e., generally at zero, resulting in no day one gain). Based on the forward price, \$80/MWh of consideration should be allocated to the energy sales (resulting in a day one fair value of \$0). The embedded energy derivative would be marked-to-market subsequent to bifurcation based, in part, on this allocated pricing.

REG would allocate the remaining consideration (\$30) to the RECs and recognize it over the term of the contract. It would not adjust the allocation established at the beginning of the contract for subsequent changes in prices.

7.7 *Accounting for compliance with renewable portfolio standards*

States and jurisdictions with renewable portfolio standards require retail electricity suppliers, such as regulated utilities and direct access suppliers, to source a specified amount of their retail load from renewable resources. Although programs vary, the retail provider typically demonstrates compliance by submitting qualifying RECs to the relevant program administrator. In general, the compliance obligation is determined based on retail load (i.e., the number of RECs to be submitted are a specified percentage of megawatt-hours sold to retail customers) and the obligation to submit RECs is incurred and increases as power is delivered to retail customers. The retail provider may be subject to fines and penalties for failure to comply with RPS requirements.

Based on the nature of the compliance obligation, if the RPS requirement is based on a percentage of retail customer load, we believe reporting entities should accrue the RPS liability as a period expense as power is delivered to retail customers.

There is diversity in practice as to the measurement of the RPS liability. We believe different approaches may be acceptable, including:

- Fair value or market price of RECs, because the liability could be settled by purchasing RECs from the market
- Weighted-average cost of RECs held in inventory (or classified as intangible assets), if those instruments are expected to be used to settle the liability
- Cost of RECs to be purchased in forward contractual arrangements

A reporting entity could also consider accounting for the RPS compliance obligation in a manner similar to the accounting discussed in UP 6.6 for compliance with emission allowance programs. In some cases, a combination of these approaches or another method of measurement may be appropriate, depending on the RPS settlement mechanism. A reporting entity should evaluate its facts and circumstances, be able to support its recognition policy under U.S. GAAP, and apply it consistently. In addition, it should recognize any potential penalties or fines when probable and estimable, consistent with the guidance in ASC 450, *Contingencies* (ASC 450).

Question 7-4

Should a reporting entity record RPS expense immediately when RECs are generated or purchased?

PwC response

Generally, no. As discussed above, the RPS liability accrues, and should be recorded, as retail deliveries occur. The timing of the purchase or generation of RECs may or may not coincide with the recognition of the liability. The measurement of the liability may include the reporting entity's actual cost of RECs or may be based on a market

measure (note that generated RECs not deemed output will have a zero cost basis because all costs will be allocated to output from the facility).

RECs purchased or generated should be capitalized as inventory or intangibles, depending on the reporting entity's policy. A compliance liability is recognized based on the reporting entity's measurement methodology. RECs held and recorded as inventory or intangible assets are offset against the compliance liability when the RECs are surrendered to the RPS program administrator to demonstrate compliance. Any difference between the liability and the carrying value of the RECs would be recognized as a gain or loss when the obligation is settled.

7.8 *Considerations for regulated utilities*

A regulated utility may be eligible to recover the cost of its RPS compliance through an energy balancing account or similar regulatory mechanism allowed by its regulator. Because the RPS requirements do not impact net income, some may believe that it is appropriate to record the cost of the RECs as purchased power expense when incurred instead of recognizing a compliance obligation.

However, similar to other expenses subject to regulatory treatment, a reporting entity should not substitute regulatory accounting for appropriate recognition under U.S. GAAP applicable to entities in general. As discussed in Question 17-13, a regulator's actions cannot eliminate a liability that it did not create. Therefore, all reporting entities, including regulated utilities, should appropriately measure and record RPS compliance liabilities. Any potential recovery by a regulated utility should be separately assessed and recorded in accordance with ASC 980.

Question 7-5

How should a regulated utility accrue its RPS compliance liability when the state requires it to procure a specified amount of qualifying renewable energy, irrespective of retail usage?

PwC response

Some states require regulated utilities to obtain a specified amount of renewable energy (e.g., Iowa requires its two investor-owned utilities to obtain a combined total of 105 megawatts of renewable power). Under this type of program, the amount of renewable energy required to be provided by retail providers is not dependent on the amount of energy they deliver to customers. Therefore, the compliance liability is often known at the start of the compliance year.

In these cases, we believe there are alternative methods a reporting entity could use to accrue its RPS compliance liability. For example, a proportionate, time-based accrual method (similar to straight-line) could be used when the retail sales volume has no bearing on the amount of the compliance requirement. Alternatively, a reporting entity may consider that it has incurred a liability at the start of the reporting period because the level of renewable energy it needs to provide is known, in which case a liability would be recorded. Different states will have different requirements and the

specifics of the program should be carefully considered prior to adopting a method of accrual. Once a methodology is selected, it should be consistently applied.

Chapter 8: ***Business combinations***

The content in this chapter referred to superseded sections of ASC 805. It is in the process of being updated. For current guidance on business combinations, refer to PwC's *Business combinations and noncontrolling interests* guide.

***Chapter 9:
Investments in power
plant entities***

9.1 Chapter overview

Reporting entities often form separate entities for the development, construction, and operation of renewable energy or other power plant facilities (referred to herein as single power plant entities). Single power plant entities typically hold a single power plant and may be corporate joint ventures, partnerships, or limited liability companies, and are often formed by power generators or regulated utilities, with investments by strategic and financial investors. Also, the capital structure of a single power plant entity may vary depending on the specific objectives of the parties involved. For example, some structures include different classes of equity owners, while other entities obtain funding through debt arrangements or a combination of debt and equity. In addition, the original developer may guarantee return or provide other incentives to debt or equity investors to obtain the necessary financing.

This chapter provides a framework for and discusses key considerations associated with the accounting by an investor for its investment in a single power plant entity (assuming consolidation is not applicable) and addresses the accounting by the entity and the investors.

See UP 10 for information on consolidation of single power plant entities, PwC's Consolidation and equity method of accounting guide for consolidation guidance in general, and UP 15 for information on accounting for undivided interests in a power plant (i.e., joint plant).

This chapter also provides guidance on how to allocate the net income of a single power plant entity to its investors, including use of the hypothetical liquidation at book value (HLBV) method. The use of the HLBV method to allocate net income is frequently used for single power plant entities, due to the nature of the profit sharing and other ownership agreements.

9.2 Scope

Consolidation guidance is included in ASC 810, *Consolidation*. ASC 810 was amended in February 2015 by ASU 2015-02, *Consolidation (Topic 810): Amendments to the Consolidation Analysis*. ASC 323, *Equity Method*, provides guidance on the equity method of accounting, and ASC 970, *Real Estate—General*, addresses the equity method of accounting for corporate joint ventures, including partnerships. Other guidance included in this chapter is as follows:

- ASC 320, *Investments—Debt and Equity Securities*
- ASC 325, *Investments—Other*
- ASC 310, *Receivables*
- ASC 470, *Debt*
- ASC 480, *Distinguishing Liabilities from Equity*

9.3 *Typical structure of a single power plant entity*

Single power plant entities generally involve a number of parties, including a variety of investors and off-takers from the power plant. These parties include:

□ *Developer*

The developer generally has equity ownership in the project and responsibility for the formation, construction, and operation of the plant. The developer may contribute cash, contractual rights, expertise, and/or physical assets to the single power plant entity in exchange for its equity interest. Assets and contracts contributed may include land, property, or equipment, offtake agreements, permits, and emission credits (credits required to build the power plant or credits needed for commercial operation).

□ *Financial investors—equity*

A single power plant entity may involve one or more equity investors who contribute cash or other assets in exchange for their interest in the entity. Equity investments can be in the form of traditional voting equity, passive participation (such as tax equity), or another form of equity ownership such as preference shares. Tax equity owners invest to benefit from a return generated by government incentives such as grants, investment tax credits, or production tax credits along with other tax attributes that come with tax ownership (e.g., tax depreciation). See UP 16 for information on accounting for government incentives.

□ *Financial investors—debt*

A project may have one or more debt investors. Debt interests are typically collateralized by the assets of the project and may or may not be guaranteed by the developer. In most cases, the debt holders have no recourse to other assets of the investors in the event of default, although a corporate or other guarantee is sometimes provided. Debt holders are usually passive participants, although debt agreements generally include standard creditor rights.

□ *Contractors*

Unless the developer is also a builder, the single power plant entity will typically enter into an engineering, procurement, and construction (EPC) contract. Once the plant becomes operational, a third-party contractor or the EPC contractor may provide ongoing operations and maintenance (O&M) services. These contracts are generally executed between the single power plant entity and the related contractors, although the owners of the entity may provide a guarantee of payments.

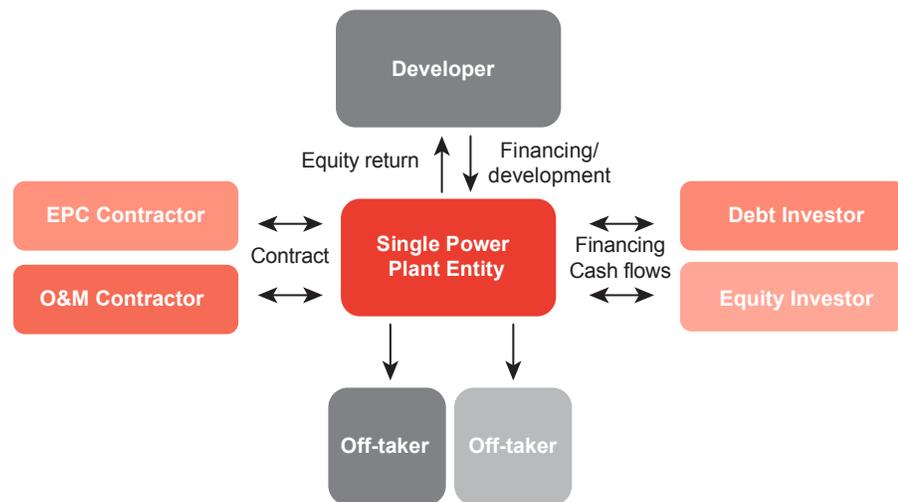
- *Off-takers*

One or more parties may agree to purchase the power, capacity, and/or other attributes of the facility (e.g., renewable energy credits) through contractual arrangements. These agreements are often required as a condition of financing. In other cases, the power plant may operate as a merchant facility, whereby all output is sold on the open market.

Figure 9-1 illustrates the potential parties involved in a typical structure.

Figure 9-1

Sample structure for a single power plant entity



One common type of structure that is used for renewable energy projects is referred to as a “flip structure.” In a flip structure, the developer partners with one or more third-party investors to monetize the tax benefits associated with owning a renewable energy facility. The tax investors are willing to invest in the entity to receive returns primarily through tax credits and other tax benefits, which may or may not be supplemented by a project’s underlying cash flows. Although single power plant entity structures may vary and all facts and circumstances should be individually analyzed, a typical partnership flip structure is configured as follows:

- A developer establishes a project company (often a limited partnership or limited liability company) and recruits a tax equity investor.
- The project company invests in a renewable energy project that is eligible to receive certain tax attributes, such as tax credits and tax depreciation benefits.
- The tax investor commits to contribute the majority of equity, in return for a majority (possibly up to 99 percent) of income and losses, including tax attributes, until it has recovered its initial investment plus a predetermined yield or internal rate of return.

- Limited partnership—an association in which one or more general partners have unlimited liability and one or more partners have limited liability. A limited partnership is usually managed by the general partner or partners, subject to limitations, if any, imposed by the partnership agreement.
- Limited liability company—companies with characteristics of both corporations and partnerships; however, they are dissimilar from both in certain respects. Examples of these characteristics are discussed in Figure 9-4 in the context of evaluating the appropriate accounting model for the investor. They include such considerations as to who has limited and unlimited or personal liability, tax liability, and control and/or management ability as examples.

The consolidation rules need to be considered regardless of the legal structure.

9.4.1 Step one: consider consolidation

As a first step, the reporting entity should assess whether consolidation of the single power plant entity is required pursuant to ASC 810. See UP 10 for information on consolidation of single power plant entities.

The first consideration is whether the entity should be consolidated under the variable interest entity (VIE) consolidation model. There is a unique consideration for partnerships in applying this model when determining if the equity holders as a group have the power to direct the activities that most significantly impact the entity's economic performance. Any limited partners would have to hold substantive kick-out or participating rights to demonstrate that power. If the entity does not lack this characteristic, and none of the other characteristics to be a VIE exist, then the voting interest consolidation model is considered.

In considering consolidation as a voting interest entity, all rights of shareholders or partners are considered in determining control, such as kick-out and participating rights. The shareholder or partner that has control when considering all of these rights will consolidate the entity.

A controlling limited partner should account for its investment following the principles for investments in subsidiaries. Noncontrolling limited partners should account for their investments by the equity or cost method. If a limited liability company is deemed to resemble a limited partnership, it would apply these same consolidation guidelines.

If a reporting entity concludes that it should consolidate a single power plant entity, it will need to determine the appropriate presentation in its consolidated financial statements of the investments in the entity held by any other parties (i.e., as noncontrolling interests or debt).

UP 9.5 addresses considerations from the perspective of the single power plant entity that would drive the presentation in the consolidated financial statements of the consolidating entity. In addition, if the consolidating entity determines that other interest holders have noncontrolling interests, it will need to consider the appropriate allocation of net income to the noncontrolling interests (see UP 9.6).

9.4.2 Step two: determine accounting model

If the reporting entity concludes that consolidation is not applicable, its next step is to determine which accounting model should be applied in accounting for its investment. Depending on the facts and circumstances, it may be appropriate to account for the interest as a debt interest, an equity interest, or as a sale of future revenue.

Figure 9-3 highlights the different potential investor accounting models and related key criteria.

Figure 9-3

Investor's evaluation of interests in a single power plant entity assuming consolidation is not applicable

Nature of investment	Potential investor accounting models	Key criteria
Equity investment (UP 9.4.2.1)	Equity method	Investor has significant influence and a residual equity interest (or in-substance common stock) or a separate capital account with at least 3% to 5% of ownership interest
	ASC 320 method of accounting for investments ¹	Investor does not have significant influence; securities have a readily determinable fair value
	Cost method	Investor does not have significant influence; securities do not have a readily determinable fair value
Debt investment (UP 9.4.2.2)	Loan/receivable	Investment in the form of a note or other loan with a maturity that extends beyond a year; investment does not qualify as a "debt security"
	ASC 320 method of accounting for investments	Applies if the investment is a "debt security" as defined; not typical in single power plant entity structures

¹ At the time of release of this guide, the FASB had an active project on its agenda to address the classification and measurement of financial instruments. Preparers and other users of this guide are encouraged to monitor the status of the project and, if finalized, consider the implications on accounting conclusions.

Nature of investment	Potential investor accounting models	Key criteria
Sale of future revenue (UP 9.4.2.3)	Loan/receivable	Sales of future revenue of the entity that constitute debt (loan for the investor) or deferred income (receivable for the investor)

9.4.2.1 Equity investments

If consolidation is not applicable, an investor may account for an equity investment using the equity method, the cost method, or as an equity investment under ASC 320.

Equity method of accounting

Application of the equity method of accounting is discussed in ASC 323, *Investments—Equity Method and Joint Ventures*.

Excerpt from ASC 323-10-05-5

The equity method tends to be most appropriate if an investment enables the investor to influence the operating or financial decisions of the investee. The investor then has a degree of responsibility for the return on its investment, and it is appropriate to include in the results of operations of the investor its share of the earnings or losses of the investee.

A key question in determining whether the equity method of accounting applies is whether the investor has significant influence over the investee. Equity method accounting is often applicable for investments in single power plant entities because they typically have a limited number of equity investors, each of which has significant influence. As discussed in UP 9.4, in performing this analysis, the first step is to consider whether the investee is a corporate entity, limited partnership, or limited liability company because the evaluation of significant influence differs depending on the entity's legal structure.

This section should be read in conjunction with PwC's Consolidation and equity method accounting guide, which provides further information on applying the equity method of accounting.

Application to investments in corporations

In accordance with ASC 323-10-15-7 and 15-8, determining whether a reporting entity can exercise significant influence over an investee that is a corporation is a matter of judgment. There is a presumption (which can be overcome) that an investment in at least 20 percent of the voting common stock (or in-substance common stock) of the investee leads to a conclusion that significant influence exists.

However, the reporting entity should analyze each investment to determine the nature of the instrument and the rights attached to those instruments. In particular, once the reporting entity has concluded that the underlying investee is a corporation, it should evaluate whether the investment qualifies as common stock or in-substance common stock, as discussed in Question 9-1 and Question 9-2.

Question 9-1

Does the equity method always apply to an equity investment in a corporation in which the investor has significant influence through ownership of preferred stock?

PwC response

No. Single power plant entities often issue one or more classes of preferred stock. ASC 323-10-15-3 indicates that the guidance on the equity method of accounting is applicable to investments in common stock or in-substance common stock of a corporation. Thus, the equity method would not apply if the investor holds only preferred stock that is not in-substance common stock. However, if the investor has any amount of common stock or in-substance common stock, all of its holdings and relationships should be considered in evaluating significant influence.

Question 9-2

How is an investment evaluated to determine if it is in-substance common stock?

PwC response

In-substance common stock is defined by ASC 323-10-20.

Definition from ASC 323-10-20

In-Substance Common Stock: An investment in an entity that has risk and reward characteristics that are substantially similar to that entity's common stock.

Whether the investment has risk and reward characteristics that are substantially similar to the investee's common stock is a matter of judgment. However, ASC 323-10-15-13 provides three characteristics to consider in assessing whether shares are substantially similar to an investment in common stock, as follows:

□ *Subordination*

The liquidation rights (and existence of any preference) of the investment should be compared with the liquidation rights of the common stock. Substantive liquidation preferences over the common stock of the entity would result in the instrument not being considered in-substance common stock.

□ *Risks and rewards of ownership*

The reporting entity should compare the investor's method of participation in the earnings, losses, dividends, and capital appreciation and depreciation of the entity with that of the common shareholders. The investment needs to provide participation consistent with that of the common shares for the instrument to be considered in-substance common stock.

□ *Obligation to transfer value*

Reporting entities should evaluate any obligations arising out of the investment to transfer value to the entity as compared to common shares. The requirement of the investor to transfer value (without a similar requirement by the common shareholders), such as a redemption payment, would result in the instrument not being considered in-substance common stock.

This guidance is not applicable if the investment is in a limited partnership or limited liability company that functions like a partnership.

Application to investments in limited partnerships

Many single power plant entities are limited partnerships. The SEC staff expects the equity method of accounting to be applied for investments in limited partnerships, unless the investor has virtually no influence over the investee.

Excerpt from ASC 323-30-S99-1

The SEC staff's position on the application of the equity method to investments in limited partnerships is that investments in all limited partnerships should be accounted for pursuant to paragraph 970-323-25-6. That guidance requires the use of the equity method unless the investor's interest "is so minor that the limited partner may have virtually no influence over partnership operating and financial policies." The SEC staff understands that practice generally has viewed investments of more than 3 to 5 percent to be more than minor.

Consistent with this guidance, and regardless of whether SEC rules would apply in connection with a particular investment, we would generally expect an equity investment in a limited partnership to be accounted for using the equity method of accounting unless the holding is less than three to five percent of the equity.

Application to investments in limited liability companies

Single power plant entities are often organized as limited liability companies. There is no specific guidance that provides one accounting model for investments in limited liability companies. Instead, the method followed will depend on whether the investee functions more like a partnership or a corporation:

- Partnership—the guidance in ASC 323-30-S99-1 applies

- Corporation—the general guidance on the equity method of accounting in ASC 323 applies

In accordance with ASC 323-30-35-3, investments in limited liability companies that maintain specific ownership accounts for each investor (similar to a partnership account structure) should be treated consistent with limited partnership investments. ASC 272, *Limited Liability Entities* (ASC 272) also provides guidance in assessing whether a limited liability company should be viewed similar to a corporation or similar to a partnership. The factors discussed in ASC 272-10-5-4 are highlighted in Figure 9-4.

Figure 9-4

Should a limited liability company be evaluated as a corporation or a partnership?

Indicators that a limited liability company should be evaluated as a corporation	Indicators that a limited liability company should be evaluated as a partnership
<ul style="list-style-type: none"> □ Members (owners) are not personally liable for the liabilities of the entity □ It is generally not necessary for one owner to be liable for the liabilities of the entity □ A board of directors and its committees control the operations 	<ul style="list-style-type: none"> □ Members are taxed on their respective shares of the limited liability company's earnings □ Financial interests may be assigned only with the consent of all of the limited liability company members □ Entity is dissolved by death, bankruptcy, or withdrawal of a member

Limited liability companies have characteristics of corporations and partnerships, but are also dissimilar from both in certain respects. Reporting entities should consider factors including the structure of the capital accounts, decision-making, tax reporting, and responsibility for liabilities of the entity. Also, the determination should be based on the predominant characteristics of the entity. None of the factors described in Figure 9-4 are determinative on their own. If the limited liability company has, on balance, more characteristics of a limited partnership than of a corporation, the reporting entity would generally apply the equity method of accounting, assuming ownership is at least three to five percent of the share capital. If the limited liability company's characteristics more closely resemble a corporation, and it does not hold significant influence (i.e., at least 20 percent of the common stock) or it more closely resembles a partnership but holds less than three percent ownership, then we would expect the application of ASC 320 or cost method.

ASC 320 equity investments

When the investment does not qualify for use of the equity method, an investor in a single power plant entity should consider whether ASC 320 is applicable. ASC 320 applies to the following types of instruments:

- Equity securities that have readily determinable fair values but are not accounted for under the equity method
- Debt securities, including debt instruments that have been securitized, and preferred stock issuances in which it must be redeemed or is redeemable with an investor's unilateral right

Therefore, when considering whether an equity investment is within the scope of ASC 320, a reporting entity needs to consider whether the instrument has a readily determinable fair value. Readily determinable fair value is defined in ASC 320-10-20.

Partial definition from ASC 320-10-20

Readily Determinable Fair Value: An equity security has a readily determinable fair value if it meets any of the following conditions:²

- a. The fair value of an equity security is readily determinable if sales prices or bid-and-asked quotations are currently available on a securities exchange registered with the U.S. Securities and Exchange Commission (SEC) or in the over-the-counter market, provided that those prices or quotations for the over-the-counter market are publicly reported by the National Association of Securities Dealers Automated Quotations systems or by OTC Markets Group, Inc. Restricted stock meets that definition if the restriction terminates within one year.

Typically, single power plant entities are private entities with a limited number of owners, and equity shares are not traded on an exchange or over-the-counter market. As a result, although the reporting entity should consider the facts in each situation, common equity interests in these entities are typically not accounted for under ASC 320.

Cost method

If the equity method of accounting does not apply and the securities are not within the scope of ASC 320, the reporting entity should apply the cost method in accordance with ASC 325, *Investments—Other*. Investors in single power plant entities will typically have sufficient holdings and involvement in activities of the entity such that the cost method will not be applicable (see UP 9.4.2.1 for information on holdings of three to five percent of limited partnerships and limited liability companies). However, if the equity method is not applicable and the investments do not have a readily determinable fair value, the investments should be recorded at cost.

² The other conditions by which an equity security will be deemed to have a readily determinable fair value are applicable to securities traded in foreign markets and mutual funds and would generally not be applicable to an investment in a single power plant entity in the United States.

ASC 325-20-05-02

Investments are sometimes held in stock of entities other than subsidiaries, namely corporate joint ventures and other noncontrolled entities. These investments are accounted for by one of three methods—the cost method (addressed in this Subtopic), the fair value method (addressed in Topic 320), and the equity method (addressed in Topic 323).

ASC 325-20-05-03

While practice varies to some extent, the cost method is generally followed for most investments in noncontrolled corporations, in some corporate joint ventures, and to a lesser extent in unconsolidated subsidiaries, particularly foreign.

Under the cost method, income is recognized only to the extent of dividends paid from the investee's accumulated earnings. The investment also should be evaluated for impairment, as applicable. See ARM 5010 for further information on accounting for cost method investments.

9.4.2.2 Debt investments

Investors in single power plant entities may at times provide funding in the form of loans or notes. In general, reporting entities with a debt investment in a single power plant entity will account for the investment as a note receivable or loan pursuant to ASC 310. Loans are defined in ASC 310-10-20.

Definition from ASC 310-10-20

Loan: A contractual right to receive money on demand or on fixed or determinable dates that is recognized as an asset in the creditor's statement of financial position. Examples include but are not limited to accounts receivable (with terms exceeding one year) and notes receivable.

In accordance with ASC 310, loans (including notes receivable) are carried at amortized cost (the initial amount recorded is the amount of cash provided to the entity). Loans should be periodically evaluated for impairment subsequent to initial recognition and measurement. See ARM 3540 and ARM 3560 for information on accounting for loans and receivables, including impairment considerations.

Question 9-3

Should notes or other debt investments in single power plant entities be accounted for as debt securities under ASC 320?

PwC response

Generally, no. ASC 320 is applicable to all investments in debt securities and defines a security as follows:

Partial definition from ASC 320-10-20

Debt Security: Any security representing a creditor relationship with an entity.

Definition from the Master Glossary

Security: A share, participation, or other interest in property or in an entity of the issuer or an obligation of the issuer that has all of the following characteristics:

- a. It is either represented by an instrument issued in bearer or registered form or, if not represented by an instrument, is registered in books maintained to record transfers by or on behalf of the issuer.
- b. It is of a type commonly dealt in on securities exchanges or markets or, when represented by an instrument, is commonly recognized in any area in which it is issued or dealt in as a medium for investment.
- c. It either is one of a class or series or by its terms is divisible into a class or series of shares, participations, interests, or obligations.

Based on the definition of a security, we would not usually expect debt financing provided to a single power plant entity to qualify for accounting as a debt security under ASC 320. Typical single power plant entities are smaller, private entities with debt that is not generally issued in bearer form, registered, traded on a securities exchange, or divisible into separate classes or series of interests. However, reporting entities should evaluate all facts and circumstances for a particular investment. For example, debt registered with the SEC may qualify as debt securities and, if so, the investor would account for it under ASC 320.

Question 9-4

Should an investment in the form of preferred stock be accounted for as a debt security?

PwC response

It depends. Certain forms of preferred stock meet the definition of a debt security in ASC 320.

Partial definition from ASC 320-10-20

Debt Security: . . . The term debt security also includes all of the following:

- a. Preferred stock that by its terms either must be redeemed by the issuing entity or is redeemable at the option of the investor

Based on this guidance, if the single power plant entity issues mandatorily redeemable preferred stock or preferred stock with an investor redemption option, the instrument would be accounted for as a debt security by the investor (see UP 9.5.1 for further

information on mandatorily redeemable instruments). Accounting under ASC 320 includes determining the appropriate classification (i.e., trading, available-for-sale, or held-to-maturity) at the time the security is acquired.

If the investment is accounted for as an available-for-sale or held-to-maturity debt security, the investor will need to assess the investment for impairment. In addition, the investor should classify any cash flows received as interest or investment income.

Question 9-5

How should a financial institution account for a loan investment in a single power plant entity?

PwC response

It is common for financial institutions to invest in single power plant entities in the form of loans or other types of debt. In accordance with ASC 310-10-20, a commercial loan issued to a single power plant entity by a financial institution would not meet the definition of a debt security. The definition of debt security excludes “loans receivable arising from consumer, commercial, and real estate lending activities of financial institutions.”

Therefore, similar to long-term notes and other loans that do not meet the definition of a security, as discussed in Question 9-3, a financial institution that makes a loan to a single power plant entity should account for the investment as a loan receivable pursuant to ASC 310.

9.4.2.3 *Sale of future revenue*

As discussed in UP 9.5.2, single power plant entity investment arrangements may be structured as a sale of future revenue from the perspective of the entity. If the entity is applying a sale of future revenue model, the investor should account for its investment as a loan or receivable. If the entity accounts for the arrangement as debt, the investor should record a loan for the investment (see UP 9.4.2.2 for information on loan accounting). If the entity accounts for the arrangement as deferred income, it would be appropriate for the investor to account for the amounts extended as a receivable. The evaluation of impairment will differ depending on whether the investor records a loan or receivable. See PwC’s Financial statement presentation guide for further information on impairment of loans and receivables.

9.4.2.4 *Fair value option*

ASC 825-10 provides reporting entities with an option to measure many financial instruments and certain other assets and liabilities at fair value on an instrument-by-instrument basis. If a reporting entity elects the fair value option for an investment, it is measured on the balance sheet at fair value with gains and losses recognized each reporting period in earnings. ASC 825-10-15-4 indicates that the fair value option is available for a recognized financial asset or financial liability.

Investments in power plant entities that are accounted for under any of the models described in UP 9.4 are financial assets and thus are eligible.

Entities are precluded from applying the fair value option to, among other items, investments in consolidated entities, investments in pension and other postretirement plans, amounts accounted for as leases, and financial instruments classified as part of the issuer's shareholders' equity. Except for investments that are being consolidated by the investor, these scope exceptions are typically not applicable to investments in single power plant entities.

Reporting entities that elect the fair value option should make the election at the time the investment is made (or in some other limited circumstances, when there is a reassessment event). Once the election is made, it is irrevocable. See FV 5 for information on the fair value option.

Considerations for equity method investments

Equity method investments are financial instruments and thus would generally qualify for the fair value option. However, we understand that both the staffs of the SEC and the FASB have indicated that an equity method investment is not eligible for the fair value option if the investment involves a significant service component. Many single power plant investment agreements include provisions for the investor to provide ongoing services to the investee. For example, one of the parties may provide operations and maintenance services or an investor may be responsible for construction. When evaluating whether to elect the fair value option for an equity method investment, a reporting entity should consider its involvement, rights, and obligations with respect to the ongoing operations of the investee, including whether and how much it is earning in fees for any services. If a reporting entity determines that it is providing significant services to the investee, it will not be able to apply the fair value option. See FV 5 for further information.

9.5 Accounting by the single power plant entity

Figure 9-5 summarizes considerations with respect to the accounting for amounts received from investors in the entity's stand-alone financial statements.

Figure 9-5
Accounting models for funds received from investors

Model	Accounting considerations
Equity (UP 9.5.1)	There is a bias that legal-form equity is accounted for as an equity interest; however, there are certain characteristics that could lead to a liability conclusion.
Liability (UP 9.5.1)	Factors that may lead to a liability conclusion in the case of legal-form equity include: (1) unconditional obligation to repay investment; (2) no residual/ownership interests in the entity.

Model	Accounting considerations
Sale of future revenues (UP 9.5.2)	The sale of future revenue guidance (ASC 470-10-25-1 and 25-2) may apply when transactions are structured such that the return is based on a percentage (up to 100%) of revenue or income.

In general, a single power plant entity accounts for financing received as part of equity or as a liability; however, these transactions may also be structured as a sale of future revenue. Irrespective of the model applied, the entity should also determine how to allocate income to the investors (see UP 9.6).

9.5.1 *Evaluating whether interests issued by the single power plant entity are liabilities or equity*

ASC 480 provides guidance on how to account for issued financial instruments that are not derivatives. Share capital is generally accounted for as equity; however, legal-form equity that encompasses certain characteristics of debt may meet the definition of a liability in ASC 480. For example, securities issued with an unconditional obligation to repay the investment plus a specified return (such as a mandatorily redeemable instrument) would be accounted for as a liability. Reporting entities need to evaluate the terms of issued equity instruments to determine whether liability or equity (or derivative) accounting applies.

Following are considerations in evaluating the classification of instruments commonly issued by single power plant entities. It should be read in conjunction with the FSP guide, which includes information on the evaluation of instruments that have characteristics of both liabilities and equity, including the classification of instruments as temporary equity. Presentation and disclosure of such instruments is included in FSP.

9.5.1.1 *Considerations for classifying instruments as liabilities*

ASC 480 does not provide general guidance on what constitutes a “liability” as opposed to “equity.” Instead, the guidance provides that certain specified legal-form equity instruments should be classified as liabilities. ASC 480-10-25 requires that issuers classify any of the following three types of freestanding financial instruments as liabilities:

- Mandatorily redeemable financial instruments
- Obligations to repurchase the issuer’s equity shares by transferring assets (applies to financial instruments other than outstanding shares)
- Certain obligations to issue a variable number of shares

A key factor is that the financial instrument must be “freestanding” to potentially require liability classification. Equity investments that are embedded in another instrument are not subject to this guidance.

Mandatorily redeemable financial instruments are more common in single power plant entity structures than obligations to repurchase issuer equity shares or obligations to issue a variable number of shares.

Freestanding financial instruments

In determining whether an instrument is subject to the guidance of ASC 480, a reporting entity needs to first assess whether the instrument meets the definition of a financial instrument and, if so, whether it is freestanding.

Partial definition from ASC 480-10-20

Financial Instrument: Cash, evidence of an ownership interest in an entity, or a contract that both:

- a. Imposes on one entity a contractual obligation either: (1) To deliver cash or another financial instrument to a second entity; (2) To exchange other financial instruments on potentially unfavorable terms with the second entity.
- b. Conveys to that second entity a contractual right either: (1) To receive cash or another financial instrument from the first entity; (2) To exchange other financial instruments on potentially favorable terms with the first entity.

Definition from ASC 480-10-20

Freestanding Financial Instrument: A financial instrument that meets either of the following conditions:

- a. It is entered into separately and apart from any of the entity's other financial instruments or equity transactions.
- b. It is entered into in conjunction with some other transaction and is legally detachable and separately exercisable.

In applying this guidance, reporting entities should assess whether the contractual agreement meets the definition of a financial instrument. Legal-form equity issued by a single power plant entity is a financial instrument because the shares provide evidence of an ownership interest in the entity. In a typical single power plant entity structure, payments to investors are often conditional on operating cash flows or some other event. Therefore, a question may arise as to whether that arrangement meets the definition of a financial instrument. However, the financial instruments definition includes obligations that are conditional on a specified event, and thus an analysis under ASC 480 would still be required.

If an agreement meets the definition of a financial instrument, the reporting entity should then assess if it is freestanding using the definition of freestanding in ASC 480-10-20 and the examples in ASC 480-10-55. In evaluating whether an investment in a single power plant entity is freestanding, one important consideration is whether other products or services are included in the investment agreement. For example, an investment commitment in an engineering, procurement, and construction contract

or a management service agreement may not be a freestanding financial instrument if the contractor is unable to legally and separately exercise the investment (e.g., sell the instrument) after the completion of the EPC services.

See FG 7.3 for further information on factors to consider when evaluating whether an instrument is freestanding.

9.5.1.2 Applying the guidance in ASC 480

If a single power plant entity determines that it has issued a freestanding financial instrument, it should evaluate the instrument under the criteria in ASC 480 to determine if liability classification is required. In general, legal-form equity in a single power plant entity structure is classified as a liability if the terms of the agreement require the shares to be redeemed through repayment of the investor's capital contribution at a specified date (or dates).

Mandatorily redeemable financial instruments should be classified as liabilities, unless redemption occurs only upon the termination or liquidation of the entity. ASC 480 defines a mandatorily redeemable financial instrument.

Definition from ASC 480-10-20

Mandatorily Redeemable Financial Instrument: Any of various financial instruments issued in the form of shares that embody an unconditional obligation requiring the issuer to redeem the instrument by transferring its assets at a specified or determinable date (or dates) or upon an event that is certain to occur.

In assessing whether an instrument is mandatorily redeemable, the entity should consider whether it has an unconditional obligation to make payments to the investor or transfer assets at a specified date (dates) or upon an event that is certain to occur. If the agreement specifies the date or dates on which repayment of the capital contribution (and redemption of the shares) will be made, with no contingencies, this type of arrangement would be classified as a liability by the single power plant entity.

In contrast, if the redemption of shares in an entity is conditional on the occurrence of an event, the shares are not considered mandatorily redeemable until such time that the event occurs or is certain to occur. For example, legal-form equity would not be classified as a liability if repayment of the instrument is required only if the board declares a dividend or distribution.

Question 9-6

How does the ability to defer scheduled repayments affect the determination of whether an instrument is mandatorily redeemable?

PwC response

Many power plant entity investment arrangements include provisions that delay or modify scheduled repayments if certain criteria are not met. For example, the

investment agreement may require a targeted level of cash flows, sufficient cash reserves, or similar factors before any payments can be made. ASC 480-10-25-6 addresses provisions that may change the timing of cash flows.

ASC 480-10-25-6

In determining if an instrument is mandatorily redeemable, all terms within a redeemable instrument shall be considered. The following items do not affect the classification of a mandatorily redeemable financial instrument as a liability:

- a. A term extension option
- b. A provision that defers redemption until a specified liquidity level is reached
- c. A similar provision that may delay or accelerate the timing of a mandatory redemption.

The FASB concluded that these types of provisions may affect the timing of the unconditional redemption obligation but do not remove the redemption requirement. Thus, consistent with this guidance, an instrument may be mandatorily redeemable even if scheduled payments are dependent on sufficient cash flows, liquidity, or other factors (e.g., operating results). An instrument with scheduled payments that may be delayed due to a lack of sufficient funds or similar factors is different from an agreement that includes a priority of distributions or similar provisions but does not include a repayment schedule or any repayment commitments. An expectation that the investment will be repaid is not sufficient to conclude the instrument is mandatorily redeemable; the agreement must specify a requirement for the issuing entity to repay the investment and contain default provisions in the event of nonpayment. In practice, reporting entities may need to consult with legal counsel to determine whether repayments are legally required pursuant to the relevant agreements.

Reporting entities should evaluate provisions that allow for the deferral of payments when considering whether an investment is mandatorily redeemable. The ability to defer payments via a provision that is unrelated to the single power plant entity's ability to repay the investment would be considered nonsubstantive and may lead to a conclusion that repayment is contingent. Examples of provisions unrelated to the ability to repay may include generation of a specified level of tax benefits or requirements to maintain cash reserves significantly in excess of amounts needed for operations.

Example 9-1 provides guidance on how single power plant entities should evaluate issued instruments under ASC 480.

EXAMPLE 9-1

Investment in a single power plant entity—issuer accounting

On May 1, 20X3, M&H Holding Company and Desert Sun Tax Company (DST) enter into an investment agreement related to SunFlower Power Company (SFP), which will

be building a 100 MW solar facility. Under the terms of the agreement, preferred shares in SFP are issued to DST in exchange for \$100 million in cash. DST will receive repayment of its contribution plus a 10% return in accordance with a payment schedule included in the agreement. However, repayments are not made unless operating cash flows are at or above an amount specified in the agreement.

The operating profits of SFP are allocated based on a waterfall distribution specified in the investment agreement. In general, profits are allocated to DST until it achieves return of its investment and its priority return; remaining amounts are allocated to M&H. Operating and liquidating cash flows are distributed similarly; however, the agreement includes specific details on the order of payments. The waterfall requires that the unpaid priority amounts from prior periods, if any, are paid first to DST, followed by priority amounts owed to DST in the current period. Any remaining amounts are distributed to M&H.

Should the preferred shares issue to DST be accounted for as equity or as a liability?

Analysis

Yes, the preferred shares issued to DST would be accounted for as a liability under ASC 480.

The shares meet the definition of a freestanding financial instrument, because they were entered into separate from any other agreement or equity instruments. Furthermore, the share agreement imposes an obligation on SFP to make distributions to DST. The agreement conveys to DST the contractual right to receive cash flows representing the initial payment of \$100 million plus a 10% return.

The financial instrument meets the definition of a mandatorily redeemable financial instrument under ASC 480 because SFP has an unconditional obligation to redeem the instrument by transferring assets at a specified time. Although there is some uncertainty about the timing of the repayment to DST (because it is dependent on a specified level of cash flows), SFP is legally required to repay the initial contribution and the 10% priority return pursuant to a repayment schedule. The repayment has priority in distribution and there are no conditional payment provisions (e.g., repayment is not contingent on declaration of a dividend). This scenario is similar to the discussion in ASC 480-10-25-6.

9.5.2 Sale of future revenues

Single power plant entities may at times enter into an arrangement with investors that represents a sale of future revenues, as discussed in ASC 470.

Excerpt from ASC 470-10-25-1

An entity receives cash from an investor and agrees to pay to the investor for a defined period a specified percentage or amount of the revenue or of a measure of income (for example, gross margin, operating income, or pretax income) of a particular product line, business segment, trademark, patent, or contractual right. It is assumed that immediate income recognition is not appropriate due to the facts and circumstances.

For example, a financial investor may provide an initial contribution to a single power plant entity in exchange for the receipt of a certain return over a 10-year period. The financial investor's motivation in this arrangement is to receive its return in the form of a portion of the tax benefits generated by the power generation facility through tax credits and tax operating losses. If a transaction involves the sale of future revenue, the single power plant entity should account for the amounts received as debt or as deferred income, depending on the specific facts and circumstances. If the transaction is essentially a financing arrangement in which the investor is providing financing to the single power plant entity in exchange for a portion of its revenues or income, the entity should account for the amounts received from the investor as debt.

ASC 470-10-25-2 provides the criteria for determining whether an obligation to provide future payments should be accounted for as debt or deferred income.

ASC 470-10-25-2

While the classification of the proceeds from the investor as debt or deferred income depends on the specific facts and circumstances of the transaction, the presence of any one of the following factors independently creates a rebuttable presumption that classification of the proceeds as debt is appropriate:

- a. The transaction does not purport to be a sale (that is, the form of the transaction is debt).
- b. The entity has significant continuing involvement in the generation of the cash flows due the investor (for example, active involvement in the generation of the operating revenues of a product line, subsidiary, or business segment).
- c. The transaction is cancelable by either the entity or the investor through payment of a lump sum or other transfer of assets by the entity.
- d. The investor's rate of return is implicitly or explicitly limited by the terms of the transaction.
- e. Variations in the entity's revenue or income underlying the transaction have only a trifling impact on the investor's rate of return.
- f. The investor has any recourse to the entity relating to the payments due the investor.

In general, ASC 470-10-25-2(b) will be met in a single power plant entity structure because the entity has significant continuing involvement in the generation of cash flows through the operation of the power plant. If this criterion is met, there is a presumption that the arrangement will be accounted for as debt by the single power plant entity.

The classification also impacts the method used to amortize the investment contribution over the life of the agreement. Amounts classified as debt are amortized using the effective interest method, while amounts recorded as deferred income should be amortized based on the units-of-revenue method (as defined in ASC 470-10-20).

9.6 *Income allocation considerations*

Investors in a single power plant entity and the entity itself will need to determine the appropriate allocation of income among the investors. Income allocation may be straightforward when all income and distributions (including distributions in liquidation) are determined based on voting interests or a fixed percentage allocated to each equity holder. However, the allocation becomes complex when there are multiple types of investors, multiple classes of shares, or differing allocations of earnings or cash distributions.

When investment agreements related to single power plant entities include different allocations among the investors for profit and loss, distributions of cash from operations, and/or distributions of cash proceeds on liquidation, additional complexities arise. When income and cash allocations vary with the lapse of time or occurrence of a certain event, it may be necessary to use the HLBV method to allocate income. Similarly, entities designed as a “flip structure” (as discussed in UP 9.3 and 9.6.2) will require an alternative allocation methodology.

Allocation using the HLBV method and when there is a “flip structure” follow. The discussions address income allocation from the perspective of an equity method investor; however, the same considerations apply to the entity itself or a consolidating entity (in its calculation of the noncontrolling interest allocation).

9.6.1 *Hypothetical liquidation at book value*

Authoritative guidance addressing the application of the equity method to complex capital structures is limited. ASC 970-323-35-16 addresses the equity method of accounting for corporate joint ventures, including partnerships, and acknowledges the different allocations that can exist.

In cases where different allocations are used, ASC 970-323 recommends care in determining the method used to allocate profits among the investors. For example, in a structure in which the developer owns all of one class of shares, while one or more tax investors own all of a different class of shares, it would not be appropriate for any of the investors to record income allocations based on their ownership percentage (known as an income statement approach) if the rights of the shares are different. Similarly, if the investors' ownership percentages or rights to distributions change after a period of time, but rights in liquidation are different, it may not be appropriate

to calculate the allocation based on the applicable percentages in the different time periods. The appropriate share of investee equity earnings to be allocated to the investors should be carefully evaluated based on the rights included in all pertinent agreements.

Excerpt from ASC 970-323-35-17

Such agreements may also provide for changes in the allocations at specified times or on the occurrence of specified events. Accounting by the investors for their equity in the venture's earnings under such agreements requires careful consideration of substance over form and consideration of underlying values as discussed in paragraph 970-323-35-10. To determine the investor's share of venture net income or loss, such agreements or arrangements shall be analyzed to determine how an increase or decrease in net assets of the venture (determined in conformity with GAAP) will affect cash payments to the investor over the life of the venture and on its liquidation. Specified profit and loss allocation ratios shall not be used to determine an investor's equity in venture earnings if the allocation of cash distributions and liquidating distributions are determined on some other basis.

A common way to apply the equity method in these circumstances is referred to as the hypothetical liquidation at book value, or HLBV, method.

The HLBV method is not an accounting principle or an accounting policy election. Rather, it is a mechanical approach to applying the equity method of accounting. Using the HLBV method, the earnings an investor should recognize is calculated based on how an entity would allocate and distribute its cash if it were to sell all of its assets for their carrying amounts and liquidate at a particular point in time (known as a balance sheet approach). Under the HLBV method, an investor would calculate its claim on the investee's assets at the beginning and end of the reporting period (using the carrying value of the investee's net assets as reported under U.S. GAAP at those reporting dates) based on the contractual liquidation waterfall (see Question 9-8 for further information on applying a liquidation approach). Current period earnings are recognized by the investor based on the change in its claim on net assets of the investee (excluding any contributions or distributions made during the period).

In practice, liquidation waterfalls are often complex and reporting entities should evaluate all pertinent agreements to determine the proper income allocation. In addition, these agreements are often developed with a focus on income tax regulations; therefore, performing the evaluation with the assistance of tax experts may be helpful.

Question 9-7

Should the hypothetical liquidation at book value approach be used when applying the equity method of accounting to an investment in a single power plant entity?

PwC response

Yes, in most circumstances. We believe this method most accurately depicts an investor's share in earnings of an investee in complex capital structures. As indicated in ASC 970-323-35-17, specified profit or loss allocation ratios should not be used to record equity earnings if the allocation of cash in operations or in liquidation is on a basis that is different from profit allocation. Said another way, it would not be appropriate to allocate income based on the investors' ownership percentages when there are profit splits among investors that vary due to events (such as one class achieving a targeted rate of return) or due to the passage of time. In these circumstances, we would expect an HLBV approach to be used to calculate the allocation of earnings among shareholders. The HLBV approach should be used by (1) investors applying the equity method, (2) a reporting entity that is consolidating a single power plant entity and needs to allocate income to the noncontrolling interests, and (3) the entity itself in determining the allocation of income to capital accounts.

Question 9-8

Should a liquidation scenario always be used when applying the hypothetical liquidation at book value approach?

PwC response

Not necessarily. As discussed in UP 9.6.1, the HLBV approach assumes that at the balance sheet date, the investee would liquidate all of its assets and allocate and distribute its cash to the investors based on the waterfall stipulated in the related investment agreements. However, in some cases, the liquidation waterfalls will not reflect the actual distributions expected if the entity continues as a going concern. For example, this would be the case if the allocations in operations are substantially different than those in liquidation. Similarly, a liquidation assumption may not be appropriate if the profit allocation percentages change among the investors based only on the passage of time and certain assets will be recognized in specific periods.

Reporting entities should consider whether the liquidation waterfall appropriately reflects the entity's economics prior to application of this method. In some situations, it may be necessary to factor in other considerations to appropriately reflect the investor's actual interest in the assets. If the continuing distributions differ from the liquidation waterfall, the pattern of continuing distributions may be a better representation of the actual interests and should be applied.

Question 9-9

How should a reporting entity account for a difference between its initial capital contribution and its underlying interest in the net assets of the investee?

PwC response

As a result of the contractual liquidation waterfall in the investment agreement, a reporting entity's interest in the underlying net assets of the investee may be in excess of its initial investment. There is diversity in practice in accounting for such basis differences. Two common methods are (1) recognition of the amount through the equity income pick-up in the first period of applying the HLBV method or (2) capitalizing and amortizing the difference over the life of the underlying investment (which may be based on the term of the investment agreement). We believe both methods are acceptable, provided the accounting policy is consistently applied and disclosed.

Question 9-10

Can a reporting entity apply the guidance on investments in affordable housing partnerships to an equity interest in a single power plant entity that is a partnership?

PwC response

No. Investors in qualified affordable housing projects receive tax benefits in the form of tax deductions from operating losses of the projects as well as tax credits similar to those provided for renewable energy and other power plant projects. Affordable housing tax credits are paid over a 10-year period and are claimed on the tax return of the tax owner of the project. Therefore, it is common for investors seeking the tax benefits to purchase an interest in a limited partnership that operates the qualified affordable housing project(s). ASC 323-740 provides specific guidance on the accounting for such credits, and allows a reporting entity investing in a qualified affordable housing project through a limited partnership to elect to recognize the benefit earned through the investment using an effective yield method—similar to recognition of interest income on a debt investment.

Although the similarities between affordable housing tax benefits and renewable energy tax benefits (e.g., production tax credits and tax depreciation) may result in a similar economic earnings pattern for a tax investor, the ASC 323-740 effective yield model cannot be used in place of the traditional equity method for equity interests in single power plant entities. There are several conditions that need to be met to apply the approach outlined in ASC 323-740-25-1; specifically, the investment should be in an affordable housing project. In addition, the SEC has stated that reporting entities should not analogize to the effective yield method.

Excerpt from ASC 323-740-S99-2

The SEC staff believes that it would be inappropriate to extend the effective yield method of accounting to situations analogous to those described in paragraph 323-740-05-3.

Based on this guidance, the effective yield method of recognizing income pursuant to ASC 323-740 should not be used when accounting for investments in a single power plant entity.

9.6.1.1 Application examples—hypothetical liquidation at book value

ASC 323-10-55 includes a useful illustration of the application of the HLBV approach. This example has been reproduced in Example 9-2. Example 9-3 also illustrates application of the HLBV approach.

EXAMPLE 9-2**Allocating income based on changes in the investor's claim on investee book value****ASC 323-10-55-49**

[Consider] all of the following assumptions:

- a. Investee was formed on January 1, 20X0.
- b. Five investors each made investments in and loans to Investee on that date and there have not been any changes in those investment levels (that is, no new money, reacquisition of interests by Investee, principal payments by Investee, or dividends) during the period from January 1, 20X0 through December 31, 20X3.
- c. Investor A owns 40 percent of the outstanding common stock of Investee; the common stock investment has been reduced to zero at the beginning of 20X1 because of previous losses.
- d. Investor A also has invested \$100 in preferred stock of Investee (50 percent of the outstanding preferred stock of Investee) and has extended \$100 in loans to Investee (which represents 60 percent of all loans extended to Investee).
- e. Investor A is not obligated to provide any additional funding to Investee. As of the beginning of 20X1, the adjusted basis of Investor's total combined investment in Investee is \$200, as follows:

Common stock	\$—
Preferred stock	\$100
Loan	\$100

f. Investee operating income (loss) from 20X1 through 20X3 is as follows:

20X1	(\$160)
20X2	(\$200)
20X3	\$500

g. Investee's balance sheet is as follows:

	1/1/X1	12/31/X1	12/31/X2	12/31/X3
Assets	<u>\$ 367</u>	<u>\$ 207</u>	<u>\$ 7</u>	<u>\$ 507</u>
Loan	\$ 167	\$ 167	\$ 167	\$ 167
Preferred stock	200	200	200	200
Common stock	300	300	300	300
Accumulated deficit	<u>(300)</u>	<u>(460)</u>	<u>(660)</u>	<u>(160)</u>
	<u>\$ 367</u>	<u>\$ 207</u>	<u>\$ 7</u>	<u>\$ 507</u>

ASC 323-10-55-54

Under this approach, Investor A would recognize equity method losses based on the change in the investor's claim on the investee's book value.

ASC 323-10-55-55

With respect to 20X1, if Investee hypothetically liquidated its assets and liabilities at book value at December 31, 20X1, it would have \$207 available to distribute. Investor A would receive \$120 (Investor A's 60% share of a priority claim from the loan [\$100] and a priority distribution of its preferred stock investment of \$20 [which is 50% of the \$40 remaining to distribute after the creditors are paid]). Investor A's claim on Investee's book value at January 1, 20X1, was \$200 (60% × \$167 = \$100 and 50% × \$200 = \$100). Therefore, during 20X1, Investor A's claim on Investee's book value decreased by \$80 and that is the amount Investor A would recognize in 20X1 as its share of Investee's losses. Investor A would record the following journal entry.

Equity method loss	\$80	
Preferred stock investment		\$80

ASC 323-10-55-56

With respect to 20X2, if Investee hypothetically liquidated its assets and liabilities at book value at December 31, 20X2, it would have \$7 available to distribute. Investor A would receive \$4 (Investor A's 60% share of a priority claim from the loan). Investor A's claim on Investee's book value at December 31, 20X1, was \$120 (see the preceding paragraph). Therefore, during 20X2, Investor A's claim on Investee's book value decreased by \$116 and that is the amount Investor A would recognize in 20X2 as its share of Investee's losses. Investor A would record the following journal entry.

Equity method loss	\$116	
Preferred stock investment		\$20
Loan		\$96

ASC 323-10-55-57

With respect to 20X3, if Investee hypothetically liquidated its assets and liabilities at book value at December 31, 20X3, it would have \$507 available to distribute. Investor A would receive \$256 (Investor A's 60% share of a priority claim from the loan [\$100], Investor A's 50% share of a priority distribution from its preferred stock investment [\$100], and 40% of the remaining cash available to distribute [$\$140 \times 40\% = \56]). Investor A's claim on Investee's book value at December 31, 20X2, was \$4 (see above). Therefore, during 20X3, Investor A's claim on Investee's book value increased by \$252 and that is the amount Investor A would recognize in 20X3 as its share of Investee's earnings. Investor A would record the following journal entry.

Loan	\$ 96	
Preferred stock	100	
Investment in investee	56	
Equity method income		\$252

EXAMPLE 9-3**Application of hypothetical liquidation at book value**

On January 1, 20X3, SunFlower Power Company (SFP) is capitalized with \$5 million of equity: \$1 million contributed by M&H Holding Company and \$4 million contributed by Desert Sun Tax Company (DST). In addition, at the time of initial capitalization, SFP had borrowed \$7 million from a third party, which it invested in plant along with \$4 million of the additional capitalization. Under the terms of the shareholder agreement, operating cash flows are distributed to the parties based on their initial equity contributions (if and when distributed). However, DST has a preference of \$6 million in liquidation, after which the remaining capital will be allocated pro-rata based on the initial equity contribution of 20%/80%. Assume that the profit and loss allocation ratio does not change and that there are no book/tax differences related to the assets; therefore, SFP performs its calculations assuming the entity would liquidate as of the balance sheet date.

The following table includes SFP's balance sheet information at January 1, 20X3 and December 31, 20X3. The balance sheet is based on net revenue of \$3 million less depreciation of \$1 million, resulting in net income of \$2 million. Assume there are no dividend distributions.

	1/1/X3	12/31/X3
Cash	\$ 1,000	\$ 4,000
Plant	11,000	10,000
Debt	(7,000)	(7,000)
Equity	(5,000)	(7,000)

DST has determined that it should apply the equity method of accounting for its investment in SFP. How should it record its investment in SFP?

Analysis

Under an income statement approach, DST would calculate and record income based on 80% of SFP's \$2 million of income, which would result in equity income of \$1.6 million. However, the income statement approach would ignore DST's priority in liquidation.

Under the HLBV method, DST would determine its claim on SFP's net assets as follows:

January 1, 20X3

In liquidation, SFP would have \$5 million available for equity holders after repayment of liabilities. DST would receive all of the \$5 million available for distribution due to its priority distribution in liquidation of \$6 million.

December 31, 20X3

Based on distributable cash flows (equity balance) of \$7 million, in liquidation, DST would receive \$6.8 million (\$6 million plus 80% of the remaining equity). The change in DST's claim on net assets is \$1.8 million (\$6.8 million claim at December 31, 20X3 less \$5 million at January 1, 20X3). Therefore, DST should recognize \$1.8 million in equity method income for 20X3.

9.6.2 Flip structures and inverted leases

Government authorities have encouraged the development of renewable energy facilities through the issuance of tax credits and government grants in exchange for the generation of clean energy. Often, investors enter into these ventures solely to earn these credits or grants and either have no equity in the power plant entity or surrender their equity at the time the incentives are earned in full. Flip structures and inverted leases are two common tax equity structures.

A tax investor may make an initial investment in the entity to finance the construction. This may take the form of equity or a loan. In exchange for this contribution, the investor will receive the rights to the tax credits or government grants generated by the production of renewable energy. Refer to UP 9.3 for more details on these types of structures. For discussion of the accounting for government grants, see UP 16.

EXAMPLE 9-4

Inverted lease structure

Tax investor A provides \$40 million cash in the form of an up-front lease payment to the developers/owners of a solar generation facility for purposes of financing the construction of the facility. Through the leased facility, the investor will enter into a power purchase agreement with an off-taker and will be entitled to all tax credits and any revenue generated through the power purchase agreement for a period of five

years. The investor is not purchasing the underlying property, but rather is receiving financial assets: (1) an investment tax credit (ITC) (fair value of \$30 million) and (2) a financing receivable (fair value of \$10 million). The tax basis of the underlying assets is \$60 million. The assets remain on the owners' books. The method for determining the resulting deferred tax asset to be recognized is based on the nature of the underlying assets acquired.

In accordance with ASC 740-10-25-51, for purchases of financial assets that are not business combinations, the assets received should be recorded at their fair value. The tax effect of asset purchases that are not business combinations in which the amount paid differs from the tax basis of the asset should not result in immediate income statement recognition.

Assume a 35% tax rate.

How should Tax Investor A and the investor recognize the transaction?

Analysis

Tax investor accounting:

On day one, the investor would record the cash outlay and the respective assets purchased (the ITC and the financing receivable). A deferred tax asset would be recorded for the book/tax basis difference of the underlying assets (\$60 million tax basis less \$40 million book basis times 35%). The excess of the fair value of the financial assets and the deferred tax asset recorded over the cash purchase price would be recorded as a deferred credit. Tax investor A would record the following journal entry.

Financing receivable	\$	10	
ITC		30	
DTA		7	
Cash			\$ 40
Deferred credit			7

Recognition of the ITC in income would follow the guidance in UP16. The financing receivable would be paid back through the revenue generated by the power purchase agreement.

Accounting for a flip structure, as discussed in UP 9.3, would be similar, except that instead of leasing the assets, the tax investor must be the owner of the assets to receive the tax credits. Once the tax credits have been exhausted, the investor will exit the project and ownership will revert to the developer.

Chapter 10:
Consolidations: variable
interest entities

10.1 Chapter overview

This chapter provides guidance on the application of the variable interest entity (VIE) consolidation model for utilities and power companies, focusing on arrangements and structures involving single power plant entities. Some of the concepts described in this chapter also may be useful to consider for other types of arrangements common in the industry, such as joint venture arrangements for transmission entities or natural gas supply arrangements. Additional guidance is provided in PwC's *Consolidation and equity method of accounting* guide (CG).

Recent standard setting

In February 2015, the FASB issued new guidance (ASU 2015-02) that amends the current consolidation guidance. The amendments affect both the VIE and voting interest entity consolidation models. Refer to CG 1.2 for discussion of these changes. For public companies, this standard is effective for annual and interim periods beginning after December 15, 2015. The discussion in this chapter reflects the new guidance.

10.1.1 Applying the variable interest entity model

Even though the variable interest entity model has been in use for several years, the guidance continues to evolve and application is complex. Figure 10-1 summarizes certain considerations that are important when applying this model.

Figure 10-1

Key considerations when applying the variable interest model

Focus on risks to identify variable interests

The first step in the VIE analysis is the identification of variable interests in accordance with the by-design model, which focuses on what risks the VIE is designed to create and pass along to its interest holders. Interests that *absorb* risk are variable interests, while those that *create* risk are not. See UP 10.2.

Consider whether an entity is a VIE

The evaluation of whether an entity is a VIE is based on specified criteria. If any of the criteria are met, the entity is a VIE. See UP 10.3.

Focus on powers to identify the primary beneficiary

The primary beneficiary is the variable interest holder with the power to direct the activities that most significantly impact the economic performance of the VIE. The primary beneficiary must also have the right to absorb losses and receive benefits that could potentially be significant to the VIE. Only one party can meet both of these criteria. See UP 10.4.

Determine the primary beneficiary based on current powers held

The determination of which activities will most significantly impact a VIE's economic performance should consider all activities over the life cycle of the entity. However, the determination of which party has the power to direct these activities is generally made based on powers currently held by variable interest holders. Terms that may change the conclusion in the future should be disclosed. See UP 10.4.1.1.

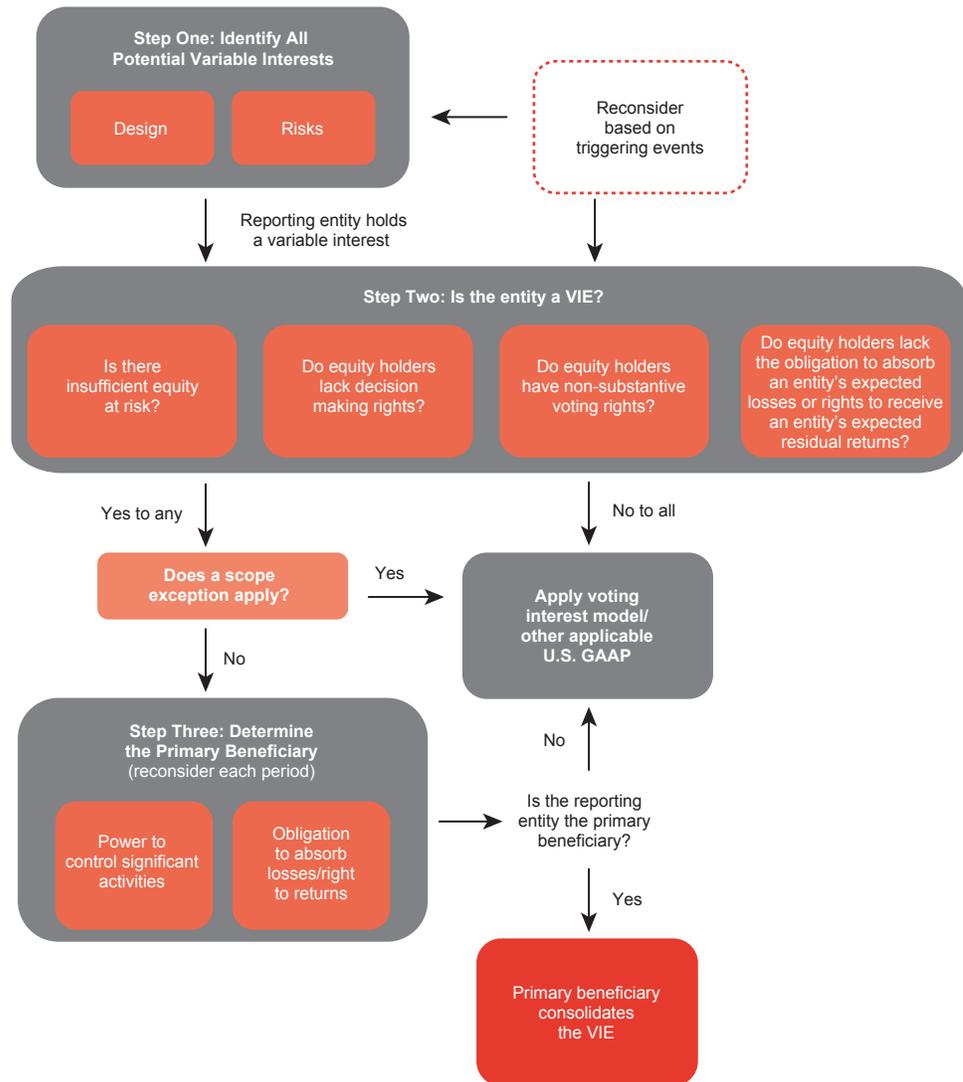
Consider whether there is no primary beneficiary

There may be circumstances where no party consolidates, such as when the most significant powers are held by a party that does not have a variable interest or when power is shared. See UP 10.4.1.4.

10.1.2 Variable interest entity framework for single power plant entities

Below is a suggested overall framework that can be applied when evaluating the accounting for one or more interests with a potential VIE.

Figure 10-2
Variable interest entity framework



This diagram is a high level depiction of the framework. The related sections of this chapter describe the details of applying each step in the framework to single power plant entities. In addition, an overview of this four-step application methodology follows.

10.1.2.1 Step one: identify all potential variable interests

When a reporting entity has a relationship with a potential variable interest entity, the first step is to determine whether it holds one or more variable interests. This assessment is based on the by-design model, which requires the reporting entity to consider the purpose of the entity being evaluated and the types of risks it was designed to create and pass along to its interest holders. This allows the reporting entity to identify which interests are absorbing risk and are thus variable interests. See UP 10.2 for further information about identifying variable interests.

10.1.2.2 Step two: determine whether the entity is a variable interest entity

Many single power plant entities are variable interest entities. Unless the entity qualifies for a scope exception, it is a VIE if it meets any of the following criteria:

- The entity lacks sufficient equity at risk to finance its activities.
- A party other than the equity holders has the power to control the activities of the entity that most significantly impact its economic performance, or the equity holders lack the obligation to absorb losses or the right to receive returns.
- The equity holders have rights that are disproportionate to their obligation to absorb losses or their right to returns and the activities of the entity are conducted substantively on behalf of the equity holder with disproportionately fewer voting rights.

ASC 810 also contains certain scope exceptions. If the entity is not a VIE, the reporting entity should evaluate whether consolidation is appropriate under the voting interest model or other applicable U.S. GAAP. See UP 10.3 for further information on evaluating whether an entity is a VIE.

10.1.2.3 Step three: determine the primary beneficiary

If the entity is a VIE, the parties will need to identify the primary beneficiary. The primary beneficiary is generally the variable interest holder that currently holds the power to direct those activities that are most significant to the VIE's economic performance. The primary beneficiary must also have exposure to losses or the right to receive benefits from the VIE that could potentially be significant to the VIE (we would expect it to be rare that a variable interest holder would not have such exposure or rights). To determine the primary beneficiary, the reporting entity should identify the significant activities of the VIE and then determine which party holds the powers to direct those activities. The evaluation should be performed each reporting period. See UP 10.4 for further information on identifying the primary beneficiary.

10.1.2.4 Step four: accounting and disclosure

The primary beneficiary is required to consolidate the variable interest entity. This results in recognition of and accounting for all of the VIE's assets and liabilities, including any noncontrolling interests, in the primary beneficiary's consolidated financial statements. In addition, all variable interest holders in a VIE, regardless of whether they are the primary beneficiary, will have to comply with the variable interest entity disclosure requirements. See UP 10.5 and FSP 18 for further information on accounting and disclosure requirements, respectively.

10.2 Variable interests

Assessing whether a contractual arrangement is a variable interest is an important element of the VIE consolidation model. This requires an assessment of the design and purpose of the entity being evaluated, as well as the risks in the entity that interest holders may be required to absorb that would result in those interests being variable

interests. The determination of which contractual and ownership interests are variable interests is based on this evaluation of the design and risks of the VIE.

Partial definition from ASC 810-10-20

Variable Interests: The investments or other interests that will absorb portions of a variable interest entity's (VIE's) expected losses or receive portions of the entity's expected residual returns are called variable interests. Variable interests in a VIE are contractual, ownership, or other pecuniary interests in a VIE that change with changes in the fair value of the VIE's net assets exclusive of variable interests.

Potential variable interests in a single power plant entity include power purchase agreements, equity interests, debt interests, management agreements, operations and maintenance agreements, and other contractual arrangements. This section discusses the overall framework for determining whether a contractual or other interest is a variable interest.

10.2.1 The “by-design” approach to determining variability and variable interests

The “by-design” model is a fundamental aspect of assessing the variable interests in a VIE. It was introduced in FASB Staff Position (FSP) No. FIN 46(R)-6, *Determining the Variability to Be Considered in Applying FASB Interpretation No. 46(R)* (FSP FIN 46(R)-6), in 2006. FSP FIN 46(R)-6 was issued to address diversity in the methods used to identify variable interests and has been codified in ASC 810.

10.2.1.1 What is the “by-design” model?

At a high level, the by-design model requires consideration of:

- The design of the entity being evaluated
- The types of risks and rewards that the entity is designed to create and that the interest holders are asked to absorb or benefit from, based on the purpose for which the entity was created
- Whether the individual interests create or absorb risks

In making the initial assessment, reporting entities should consider all contractual documents that relate to the entity, including those concerning formation, governance, marketing, and other arrangements with interest holders. Each of these sources of information provide insight into the risks the entity was designed to create and which parties are expected to absorb those risks or receive associated benefits. Those interests that absorb risk and the variability created by those risks should be assessed as variable interests.

10.2.1.2 How is the by-design model applied?

ASC 810-10-25-22 provides guidance for applying the by-design model.

ASC 810-10-25-22

The variability to be considered in applying the Variable Interest Entities Subsections shall be based on an analysis of the design of the legal entity as outlined in the following steps:

- a. Step 1: Analyze the nature of the risks in the legal entity (see paragraphs 810-10-25-24 through 25-25).
- b. Step 2: Determine the purpose(s) for which the legal entity was created and determine the variability (created by the risks identified in Step 1) the legal entity is designed to create and pass along to its interest holders (see paragraphs 810-10-25-26 through 25-36).

Considerations in applying this model to a single power plant entity follow.

Step 1: analyze the risks in the entity

The guidance outlines potential risks to be considered, including credit risk, interest rate risk, commodity price risk, and operations risk. This list is not all inclusive, and reporting entities should consider all risks in the entity. Risks typical to a single power plant entity include:

- Construction risk associated with building the power plant
- Price risk related to changes in the value of the power plant asset
- Credit risk associated with sales or purchase agreements
- Commodity price risk
- Production risk (for certain renewable plants or experimental technology)
- Operations risk associated with operating the power plant

Reporting entities should also consider other potential risks (e.g., foreign currency exchange risk if the power plant is located in another country and interest rate risk associated with any investments) in evaluating the overall design of the entity. When assessing the risk profile of a single power plant entity, it may be beneficial to consider the characteristics of a merchant generator regardless of the nature of contracts that may be in place (e.g., power purchase agreement, fuel supply contract, regulatory authority). This will ensure that a full analysis of potential risks has been considered in the evaluation, even if certain of those risks may have been allocated among entities by the design of the legal entity.

Step 2: determine the purpose for the entity and variability

As discussed in ASC 810-10-25-25, the identification of risks and variability in a variable interest entity should incorporate all relevant facts and circumstances, including the entity's activities, terms of the entity's contractual arrangements, nature

of ownership interests issued, how interests were negotiated with or marketed to potential investors, and which parties participated in the entity's design.

ASC 810-10-25-26 further states that other contracts may appear to both create and absorb variability and that the assessment of whether the contract is a variable interest should be based on the role of the contract in the design of the entity, regardless of its legal form or accounting classification. The guidance also highlights a number of strong indicators that suggest whether an interest is a variable interest (i.e., an absorber of variability).

Excerpt from ASC 810-10-25-26

Typically, assets and operations of the legal entity create the legal entity's variability (and thus, are not variable interests), and liabilities and equity interests absorb that variability (and thus, are variable interests).

A qualitative evaluation of the design of the entity often is sufficient to identify the variability that should be considered and to determine which interests are variable interests. ASC 810-10-25-30 through 25-36 also provide the following indicators to consider in evaluating variability:

- Terms of interests issued — is risk and/or return of assets or operations of the VIE transferred to the interest holder? This is a strong indication of the type of variability the entity is designed to create and pass along to interest holder(s).
- Subordination — if both senior and subordinated interests are issued, is the interest substantively subordinate to senior interests? This is another indication that the interest is designed to absorb variability.
- Certain interest rate risk — will interest rate fluctuations result in variations in cash proceeds from sales of fixed-rate investments or other investments that will be sold prior to maturity to meet the entity's obligations? This is a strong indicator that the entity was designed to pass along this variability to its interest holders.
- Certain derivative instruments — is the interest a derivative with an underlying based on an observable market price and with a counterparty senior to other interest holders? If yes, this is a strong indication that the derivative creates, rather than absorbs, variability of the entity. However, even if these two conditions are met, a derivative may still be a variable interest, if it absorbs the variability associated with the majority of the VIE's assets or operations. In such cases, further evaluation would be necessary.

A single power plant entity is not typically designed to pass along interest rate risk to its variable interest holders; therefore, this risk is not further discussed in this section. See CG 2.2.2.3 for further information on considerations related to the evaluation of interest rate risk.

Question 10-1

How should a reporting entity assess whether a power purchase agreement is a variable interest?

PwC response

In accordance with ASC 810, the by-design model should be used to identify the types of variability in an entity that may create a variable interest. However, at the time FASB Interpretation (FIN) No. 46 (revised 2003), *Consolidation of Variable Interest Entities, an interpretation of ARB No. 51* (FIN 46(R)), was originally adopted, practice developed whereby reporting entities applied one of two methods in evaluating whether a power purchase agreement was a variable interest: the “fair value method” or the “cash flow method.”

- Fair value method — focuses on whether the contract being analyzed shields the variable interest entity from changes in the fair value of its assets. As a general rule, a contract would be a variable interest if the existence of the contract reduces the variability in the value of the variable interest entity’s assets.
- Cash flow method — focuses on whether the contract directly absorbs some or all of the operating cash flows of the variable interest entity.

As discussed above, the FASB issued FSP FIN 46(R)-6 to address this diversity in practice. The guidance was codified in ASC 810-10-25-23.

Excerpt from ASC 810-10-25-23

After determining the variability to consider, the reporting entity can determine which interests are designed to absorb that variability. The cash flow and fair value are methods that can be used to measure the amount of variability (that is, expected losses and expected residual returns) of a legal entity. However, a method that is used to measure the amount of variability does not provide an appropriate basis for determining which variability should be considered in applying the Variable Interest Entities Subsections.

In accordance with this guidance, reporting entities should apply the by-design model to determine the type of variability that may create a variable interest. The cash flow and fair value methods may then be used to measure the amount of variability. ASC 810-10-55-55 provides examples of how to apply the by-design model. See UP 10.6 for examples of applying the by-design model in evaluating potential variable interests in a single power plant entity.

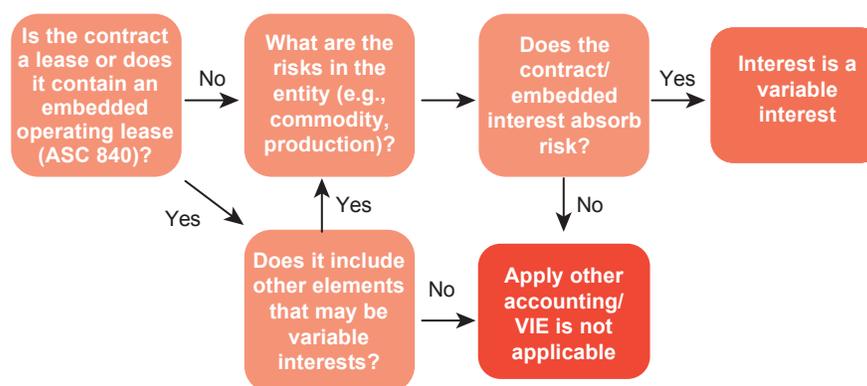
The following sections include information on how to assess potential variable interests in single power plant entities (e.g., power purchase agreements and equity investments) using the by-design model.

10.2.2 Power purchase agreements

Many single power plant entities include plant-specific power purchase agreements. The accounting for and evaluation of a power purchase agreement under the variable interest entity model depends, in part, on how the entity accounts for the power purchase agreement (i.e., lease, derivative, or nonderivative executory contract). Therefore, the evaluation of whether a power purchase agreement is a variable interest begins with a determination of the appropriate contract accounting model. Figure 10-3 depicts the overall process for evaluating whether a power purchase agreement is a variable interest.

Figure 10-3

Evaluating whether power purchase agreements are variable interests



Power purchase agreements may create or absorb various risks, including commodity price risk, production risk, operations risk, fuel risk, and credit risk.

10.2.2.1 Is the contract a lease or does it contain an embedded lease?

Power purchase agreements are often accounted for as leases in accordance with ASC 840. To preserve the existing model for lease accounting, the FASB provided a specific exception in the VIE guidance for those agreements qualifying as operating leases.

Excerpt from ASC 810-10-55-39

Receivables under an operating lease are assets of the lessor entity and provide returns to the lessor entity with respect to the leased property during that portion of the asset's life that is covered by the lease. Most operating leases do not absorb variability in the fair value of a VIE's net assets because they are a component of that variability. Guarantees of the residual values of leased assets (or similar arrangements related to leased assets) and options to acquire leased assets at the end of the lease terms at specified prices may be variable interests in the lessor entity.

Consistent with this guidance, in general, an operating lease agreement (including an operating lease embedded in a power purchase agreement) where the VIE is the lessor is not a variable interest. However, all contractual arrangements, including operating leases, should be evaluated to determine if the agreements contain other embedded

elements that should be evaluated as variable interests. Therefore, reporting entities should not automatically bypass operating lease contracts in the evaluation of variable interests. Potential variable interests in a lease include:

- Lessee residual value guarantees
- Lessee purchase option or call at specified prices
- Lessee renewal options at a specified price other than fair value
- Put option on the leased assets by the VIE

These instruments generally provide an “option” or impose an “obligation” that triggers with a change in the price of the asset and either entitle a holder to a gain (purchase option) or obligate it to incur a loss (residual value guarantee). As highlighted in ASC 810-10-55-39, these elements likely represent variable interests that require further consideration in the evaluation of the primary beneficiary.

Question 10-2

Is a contractual arrangement accounted for as a capital lease a variable interest?

PwC response

It depends. The lease exception included in ASC 810-10-55-39 is specifically provided for operating leases and does not extend to capital leases. The guidance states that operating lease receivables do not absorb variability (thus are not variable interests) because they are a component of the variability of the fair value of the VIE’s net assets.

In evaluating whether a capital lease is a variable interest, a reporting entity should gain an understanding of the reasons the lease is classified as a capital lease. Capital leases that are the substantive equivalent of a loan would not be a variable interest. These are the types of leases that require the lessee to pay periodic rents for a term that is at least 75% of the property’s economic life or that amounts to at least 90% of the property’s value. In contrast, capital leases that contain fixed price purchase options or residual value guarantees would be considered to contain variable interests. The reporting entity may conclude that this type of lease arrangement is a creator of variability, similar to an operating lease (i.e., because the capital lease is a financial receivable for the entity, it is a creator of risk).

All lease agreements should also be analyzed to determine whether they include a variable interest such as an embedded operations and maintenance agreement, a residual value guarantee, or some other protection against variability. Even if the capital lease itself is deemed not to be a variable interest, such components within the agreement may be variable interests that would require further consideration.

Question 10-3

Is a contract that otherwise qualifies as a lease, but that was grandfathered under the transition provisions of EITF 01-8, eligible for the lease exception provided by ASC 810?

PwC response

No. The lease exception applies only to contracts that are accounted for as leases. It should not be applied by analogy to other contracts that are economically similar to leases but that are not accounted for as leases. Prior to the Codification, EITF 01-8, paragraph 16, provided the following transition provisions, in part:

The consensus in this Issue should be applied to (a) arrangements agreed to or committed to, if earlier, after the beginning of an entity's next reporting period beginning after May 28, 2003, (b) arrangements modified after the beginning of an entity's next reporting period beginning after May 28, 2003, and (c) arrangements acquired in business combinations initiated after the beginning of an entity's next reporting period beginning after May 28, 2003.

Thus, some power purchase contracts that include embedded leases under the provisions of ASC 840 do not follow lease accounting because they were "grandfathered" by EITF 01-8. These contracts are not eligible for the exception provided for leases and should be analyzed as potential variable interests.

Question 10-4

Are energy price and dispatch risks part of the design of an entity if the generating plant has been fully contracted to a third party in an agreement accounted for as an operating lease?

PwC response

Generally, no. Power purchase agreements may be structured in terms of the output from the property (e.g., the off-taker has the right to all power produced from the facility and has the right to dispatch). However, if the power purchase agreement is a lease, the agreement is effectively for the use of the property itself, and not for the purchase of the output from the property. As such, dispatch and energy price risk are exposures for the lessee and are thus primarily outside the design of the entity. However, in many cases, the offtake agreement includes some payment amounts that are contingent on future operations (e.g., variable operations and maintenance payments based on plant dispatch and/or energy production). These contingent payments allow the owner/operator to participate in the success or failure of the off-taker. The variability of rents linked to volume is included in the design of the entity and is generally absorbed by the equity participants.

Embedded fuel or operations and maintenance agreements

In addition to the potential variable interests highlighted above that may be embedded in a lease, leases may also include fuel, management, operations and

maintenance, or other service agreements. This type of embedded agreement may create or absorb risk in the entity, depending on its terms.

For example, in a tolling agreement, only a portion of the payments (the amount related to the contractual use of the plant) represent minimum lease payments and related executory costs under ASC 840. The remainder of the payments would be identified as contractual payments to the VIE for management and operations. Similarly, a fixed-price arrangement or a heat rate contract may also include an element for fuel (i.e., an embedded fuel supply agreement). The energy component may be separately identified in the agreement or included in another cost element. Depending on the structure and contractual terms, these types of embedded agreements may represent variable interests, because payments for fuel or operations and maintenance may absorb a significant amount of the variability of the entity.

In assessing whether these contracts absorb risk, the reporting entity should evaluate whether the entity has more risk with or without the contract. For example, the entity may be exposed to some risk associated with a long-term operations and maintenance agreement if the pricing is based on an inflation escalator (i.e., the entity has risk that its costs will increase faster than inflation). However, without the agreement, the entity would be exposed to potential volatility and uncertainty and the risk that its costs may not be recovered. Therefore, in this fact pattern, the embedded operations and maintenance agreement is a net *absorber* of risk from the entity and is a variable interest. The factors for evaluating embedded agreements are similar to those considered in evaluating nonlease power purchase agreements (see UP 10.2.2.2).

10.2.2.2 Does a power purchase agreement or embedded interest create or absorb risk in the entity?

If a power purchase agreement does not qualify for the operating lease exception or if there are potential variable interests embedded in an operating lease,¹ the reporting entity should perform further analysis of the design of the entity to determine if the power purchase agreement is a creator or absorber of risk. Key considerations in making this assessment include the nature of the contract, the rights that it conveys to the holder, and the interaction with other interests in the entity. The evaluation should follow the by-design model as discussed in UP 10.2.1. ASC 810-10-55-27 through 55-28 also provide guidance on how to evaluate fixed-price forward contracts.

ASC 810-10-55-27

Forward contracts to buy assets or to sell assets that are not owned by the VIE at a fixed price will usually expose the VIE to risks that will increase the VIE's expected variability. Thus, most forward contracts to buy assets or to sell assets that are not owned by the VIE are not variable interests in the VIE.

Conversely, ASC 810-10-55-28 indicates that fixed-price forward contracts to sell assets that *are* owned by the entity generally absorb or reduce variability and are

¹ Note—For simplicity, the remainder of this section refers to the evaluation considerations in the context of a power purchase agreement. However, the same considerations would apply in the evaluation of elements embedded in a lease. See UP 10.6 for application examples that include embedded elements.

variable interests with respect to the assets. ASC 810-10-55-29 provides additional guidance in the context of derivative instruments; however, this guidance is also helpful in the evaluation of all types of power purchase agreements (other than leases, as specifically discussed above).

ASC 810-10-55-29

Derivative instruments held or written by a VIE shall be analyzed in terms of their option-like, forward-like, or other variable characteristics. If the instrument creates variability, in the sense that it exposes the VIE to risks that will increase expected variability, the instrument is not a variable interest. If the instrument absorbs or receives variability, in the sense that it reduces the exposure of the VIE to risks that cause variability, the instrument is a variable interest.

In evaluating whether a power purchase agreement creates or absorbs risk, the reporting entity should assess the pricing structure of the contract and the nature of the entity's operations. Case H in ASC 810-10-55-81 through 55-86 illustrates the application of the by-design model to a VIE with a power purchase agreement.

Whether a contract creates risk for the entity or absorbs a risk already existing in the entity is a key factor in determining whether a contract is a variable interest. If the intent of the contract within the design of the VIE is to absorb an element of its risk, absent an exception to the accounting, it will be a variable interest. Reporting entities should also consider the relative seniority of the contract. A contract that appears to absorb risk may not be a variable interest if it is senior to debt and equity interests and its use as a risk absorber is remote. See the response to Question 10-5 for further information.

In evaluating power sales agreements that are not leases, the entity is selling output that has not yet been generated (and is thus not owned). Therefore, in applying this guidance to these types of arrangements, we typically consider the risk associated with activities necessary to produce the output. If the entity has a fixed-price power sales agreement and is exposed to fuel price risk, the analysis generally follows the evaluation for a fixed-price contract for sale of an asset that is not owned because of the procurement risk associated with fuel (assuming that the entity has not locked in the price of fuel through long-term contracts or financial hedges). However, if there is no fuel price risk because it is absorbed in the contract (such as in a tolling agreement), fixed in the initial design, or otherwise not applicable to the entity (as in the case of a renewable plant), the evaluation of a fixed-price contract would more closely follow that for an asset that is owned.

In another scenario, if a power plant is designed to sell some of the output into the market and some through a power purchase agreement, the power purchase agreement may be a variable interest since the single power plant entity is designed to take on some commodity price risk.

Figure 10-4 summarizes application of this guidance to common power purchase agreements (assuming the contracts are not leases). The design of the entity, the contract terms, and other contractual arrangements should be evaluated in determining whether a specific contract creates or absorbs risk. All power purchase

agreements create credit risk, unless fully collateralized. However, unless the contract is with a counterparty that has an unusual level of credit risk that is not appropriately mitigated by the contract terms, credit risk generally would not change the conclusion as to whether the contract is a creator or absorber of risk in an entity. As noted in Figure 10-4, the considerations for renewable energy projects and fossil fuel plants may vary due to differences in the risk profiles of the production facilities.

A reporting entity should consider the design of the entity as well as a contract's predominant characteristics in considering whether it is a creator or absorber of risk. For example, a fixed-price contract may escalate with inflation or have scheduled increases over the life of the contract. Although the price is changing over time, this contract is predominantly fixed price because the purchase price does not fluctuate with fuel or energy prices.

Figure 10-4

Variable interests: Evaluation of common power purchase agreements

Power plant type	Contract type	Considerations	Evaluation
Fossil (e.g., coal, natural gas)	Fixed-price contract	A fixed-price contract for an asset that is not owned creates risk (fuel price risk).	Contract generally creates risk and is generally not a variable interest (ASC 810-10-55-27), unless fuel cost is also fixed in the initial design.
	Tolling agreement	Effectively a service agreement; absorbs commodity price risk. Volume-based pricing may create risk.	Contract absorbs risk and is likely a variable interest.
	Heat rate contract	Protects the entity from natural gas/energy price risk; ensures return. Level of return may have variability if payments are linked to volumes.	A heat rate contract based on the plant heat rate absorbs risk and is likely a variable interest.
Renewable (e.g., wind, solar)	Fixed-price contract; no minimum quantity guarantee ¹	A fixed-price contract absorbs commodity price risk. Variability of volume is risk retained in the entity.	Contract absorbs risk and is likely a variable interest.

Power plant type	Contract type	Considerations	Evaluation
	Fixed-priced contract; minimum quantity guarantee ¹	A fixed-price contract absorbs commodity price risk; however, a minimum guarantee may create production risk for the VIE.	Further evaluation is required. The assessment depends on level of risk associated with production guarantee.
	Variable price contract; linked to price of natural gas	Contract price linkage creates commodity price exposure to the entity.	Contract creates risk and is not a variable interest.
	Fixed-priced contract up to certain production level; price reduced for additional production above specified quantity	A fixed-price contract generally absorbs commodity price risk; however, a reduction in price may create production risk for the VIE.	Further evaluation is required. The assessment depends on the magnitude of the pricing change.

¹ Minimum quantity guarantees are commonly included in renewable energy power purchase agreements and are typically supported by an engineering study that projects, at a high statistical confidence level, the expected output of an asset. If the minimum guaranteed production level is not achieved, the contract usually includes a penalty or default clause compensating the off-taker.

The following discussion provides a general framework for the evaluation of different types of contracts; however, each contract should be evaluated in the context of its individual facts and circumstances. See UP 10.6 for examples of how to determine whether various types of contracts are variable interests.

Fossil fuel projects

Fossil fuel projects include coal, oil, and natural gas-fired power plants. The operations of, and production of electric energy from, fossil fuel plants are generally highly reliable. However, these types of power plants are exposed to fluctuations in the price of fuel, which is often volatile. Key evaluation factors when considering whether different types of power purchase agreements create or absorb risk in a fossil fuel plant are discussed below. These discussions assume that the contracts are not accounted for as leases.

Fixed-price contracts

The evaluation of a fixed-price contract that is not a lease generally follows the guidance for forward contracts in ASC 810-10-55-27. In the case of a fixed-price power sales agreement sourced by a specific power plant, the entity has the ability to create energy but may not own all of the primary inputs that would be consistent with ownership of the asset (primarily the fuel supply). In the case of a natural gas or other fossil fuel plant, a fixed-price contract exposes the entity to fuel price risk because the

quantity required under the contract must be delivered regardless of the cost of production. Therefore, consistent with the guidance in ASC 810-10-55-27, fixed-price power sales agreements are usually not variable interests because these contracts are designed to create, rather than absorb, risk in the entity.

However, a reporting entity should consider all contractual arrangements of the entity in evaluating the design. For example, if the entity signs a fixed-price long-term fuel-supply agreement as part of its formation and concurrently a fixed-price power sales agreement, the fuel supply and power sales agreement together absorb the entity's commodity price risk. Furthermore, the design may be such that the fixed price established in the contract is high enough to assure a certain degree of gross margin, thereby in fact absorbing a high degree of variability. In such cases, the power sales agreement may be a net absorber of commodity risk in the entity. Consideration should be given to the lengths and terms of the respective contracts. A short-term fuel-supply agreement may not sufficiently absorb risk from an entity that has a long-term power sales agreement in place. Contracts rarely cover the full life of a power plant asset, so the duration of the agreements may be a relevant factor. Refer to Question 10-6.

Tolling agreements

In a tolling agreement, the off-taker provides its own fuel for production and the generator provides energy based on a specified heat rate (typically based on the operations of the underlying facility). In a tolling agreement, fuel price risk is absorbed through the contract and the off-taker is effectively paying the entity for a conversion service. This type of contract absorbs a significant amount of risk from the entity because it has locked in a defined level of profit on its future sales. The entity generally retains some operational risk, including the risk that it will not operate at the level of efficiency specified in the contract (based on the specified heat rate), that its cost of operations will increase faster than the level of reimbursement provided in the tolling agreement, and that unscheduled down-time will result in reduced capacity payments.

In evaluating whether the contract is a creator or absorber of risk, the entity should generally perform a "with-and-without" analysis (i.e., is there more risk with or without the contract?). Although the entity may have risk associated with increases in the cost of operations or decreases in the efficiency of the plant, this risk is typically minimal compared to the risk of volatility associated with operating as a merchant plant. In addition, some tolling agreements expose the entity to market price risk because cash flows vary depending on dispatch; however, again, this exposure is usually minimal compared to operations without the contract. As such, a tolling agreement protects the debt and equity holders and typically provides assurance of future cash inflows. Therefore, in general, we would expect this type of agreement to be a variable interest.

Heat rate contracts

A single power plant entity may enter into a power sales arrangement that passes through fuel costs to the buyer, based on a specified heat rate. The heat rate represents the efficiency of the power generating plant, or the amount of energy used by a power plant to generate one kilowatt hour (kWh) of electricity. The higher the heat rate, the lower the plant efficiency. The specific arrangement may vary to meet

the needs of the power plant and the off-taker. For example, a power plant may operate as a base load unit, with a specified amount of fuel and energy provided every day, while a peaking facility may dispatch as requested by the off-taker. In general, the risk profile of a heat rate contract is similar to a tolling agreement because fuel price risk is passed along to the off-taker.

However, depending on the structure of the heat rate contract, the entity may retain some exposure to fuel prices. Thus, the parties to a heat rate contract should not automatically conclude that it absorbs fuel risk of the entity. For example, if the heat rate in the contract is higher than the heat rate of the plant (i.e., because it is market-based rather than based on the operating profile of the power plant), profitability will fluctuate with changes in natural gas prices. In a heat rate contract, the off-taker may pay for (or supply) a specified amount of natural gas, based on the specified heat rate. If the heat rate is higher than the plant heat rate, the off-taker will pay more for natural gas than will be purchased by the plant operator for use in generation. As a result, the entity retains exposure to fuel price risk: as natural gas prices increase or decrease, the seller's profit will increase or decrease irrespective of the efficiency of the power plant. For example, if natural gas prices increase from \$2/MMBtu to \$10/MMBtu, the seller's net profit will increase.

Heat rate contracts should be evaluated to determine whether they are a net absorber of risk based on their specific facts and circumstances. In general, we would expect a heat rate contract to be a net risk absorber (and thus a variable interest).

Renewable energy projects

Renewable energy projects include wind, solar, geothermal, biomass, hydro, landfill gas, and other renewable sources. The risk profile of these types of power plants is significantly different from fossil fuel facilities. In some cases, such as wind or solar, production is highly dependent on the location of the facility and the availability of wind or the sun. Although the reporting entity can influence the success of the plant based on the initial strategic location decisions, ultimately the plant's operations are heavily dependent on weather. In contrast, a biomass, geothermal, landfill gas, or hydro resource may have significantly higher reliability once the original source of supply is established. These reliability differences may impact the evaluation of whether a particular type of power purchase contract is a variable interest. Considerations in evaluating contracts with renewable facilities are discussed below.

Fixed-price contract, no production guarantee

In general, a power purchase agreement in a renewable energy project that establishes a specified price for the quantity provided (e.g., certain qualifying facilities contracts) with no production guarantee is likely a variable interest. For a typical renewable energy project, the ongoing cost of production is generally minimal and limited to the cost of operations and maintenance (there is usually minimal to no cost associated with the source of supply). As a result, a fixed-price sales agreement protects the entity from the commodity price risk associated with sales into the energy markets (i.e., the agreement absorbs risk from the entity and the entity has less risk with the contract).

Fixed-price contract, production guarantee

Consistent with the discussion above, a fixed-price contract with a production guarantee establishes a fixed price for the power delivered and thus protects the entity against commodity price risk. Therefore, the contract is absorbing risk from the entity. However, if the contract includes a production guarantee, it may also create some level of risk to the entity. In evaluating whether the contract is a variable interest, the reporting entity needs to evaluate the significance of the risk created. In many cases, such as a geothermal or biomass plant, production at some level may be virtually assured and a production guarantee may create minimal additional risk for the entity.

However, for less established technologies, especially when the contract is signed before there is any operating history, a production guarantee may create significant risk for the entity, depending on the level of the guarantee compared to the expected output. For example, if the entity has wind studies demonstrating an expected capacity factor for a facility of 65%, a 35% production guarantee will create much less risk than a 60% guarantee, depending on the reliability of the original studies. In evaluating this type of contract, the level of the guarantee (and associated default provisions), the reliability of production (based on experience with the same or similar projects), and any other uncertainties inherent in the project should be considered.

Variable-price contract

There are numerous existing qualifying facilities contracts with pricing linked to the price of natural gas, the incremental production price of the local utility, or other commodity-related benchmarks. Any linkage of payment for production from renewable energy projects to another commodity, such as natural gas, or to the utility's cost of production creates a new risk for the entity. For example, a typical renewable project may not have any exposure to the price of natural gas; a contract linked to the price of natural gas creates a new exposure. Thus, this type of contract is a creator of risk and not a variable interest.

However, other types of variable-price contracts (e.g., contracts with linkage to the consumer price index or another index intended to replicate changes in employee costs) would need to be evaluated to determine whether and how the arrangement creates or absorbs risk. In general, any indexation or external price linkage should be evaluated to determine whether it introduces risk to the entity or absorbs a risk likely to be present.

Question 10-5

Are there any specific considerations for power purchase agreements that are derivatives?

PwC response

Yes. ASC 810 provides specific guidance for the evaluation of derivative instruments, focusing on whether the derivative will be a creator or absorber of risk for the entity. This guidance applies to all derivatives, including contracts that meet the normal

purchases and normal sales scope exception. In addition, the guidance provides a helpful framework in considering all power purchase agreements.

Excerpt from ASC 810-10-25-35

The following characteristics, if both are present, are strong indications that a derivative instrument is a creator of variability:

- a. Its underlying is an observable market rate, price, index of prices or rates, or other market observable variable (including the occurrence or nonoccurrence of a specified market observable event.
- b. The derivative counterparty is senior in priority relative to other interest holders in the legal entity.

Excerpt from ASC 810-10-25-36

If the changes in the fair value or cash flows of the derivative instrument are expected to offset all, or essentially all, of the risk or return (or both) related to a majority of the assets (excluding the derivative instrument) or operations of the legal entity, the design of the legal entity will need to be analyzed further to determine whether that instrument should be considered a creator of variability or a variable interest.

In accordance with this guidance, if the derivative counterparty is senior to other interests in the entity *and* the pricing is based on a market-based index, the derivative is likely a creator of variability. If the contract is an absorber of risk, its seniority should be considered to determine if it will be treated as a variable interest. A derivative that has seniority to other interests is generally not a variable interest because its seniority would require both debt and equity holders to absorb losses before the derivative counterparty. In such cases, the derivative's use as a risk absorber would be remote.

In analyzing common single power plant entities, the debt is often the most senior interest and the power purchase agreement is typically subordinate to the debt. In all cases, whether the power purchase agreement is a derivative or accounted for as an executory contract, the reporting entity should focus on the risks in the entity and whether the contract will create or absorb risk in evaluating whether it is a variable interest.

Question 10-6

Does the length of a contract factor into the variable interest determination?

PwC response

It depends. In evaluating whether a short-term offtake agreement (e.g., one year) could be a variable interest, the key factor to consider is whether a contract of limited duration will substantively impact the risk and economic performance of the entity.

ASC 810-10-15-13A

For purposes of applying the Variable Interest Entities Subsections, only substantive terms, transactions, and arrangements, whether contractual or noncontractual, shall be considered. Any term, transaction, or arrangement shall be disregarded when applying the provisions of the Variable Interest Entities Subsections if the term, transaction, or arrangement does not have a substantive effect on any of the following:

- a. A legal entity's status as a VIE
- b. A reporting entity's power over a VIE
- c. A reporting entity's obligation to absorb losses or its right to receive benefits of the legal entity.

ASC 810-10-15-13B further states that applying this guidance is a matter of judgment. The FASB added these provisions to ensure that reporting entities consider substance over form in evaluating an entity's structure and contractual relationships. In considering a single power plant entity, in some situations, a short-term arrangement (e.g., one month or one year) may not be a variable interest based on entity design or other factors.

10.2.3 Other potential variable interests

This section highlights key considerations in evaluating other interests that are often present in a single power plant entity structure.

10.2.3.1 Equity and debt interests

Equity and debt interests are among the most obvious forms of variable interests. Single power plant entities typically have at least one equity holder (e.g., common or preferred stock, partnership interests, membership interests). In addition, these entities usually issue other debt or equity interests, which may be structured as secured financings, preferred returns, or legal form equity. Factors to consider in the evaluation of debt and equity interests are discussed in ASC 810-10-55-22 through 55-24 and include:

- *Equity*

If an equity investment is at risk, or if it absorbs or receives some of the entity's variability, it is a variable interest. In general, legal form equity investments are variable interests unless the source of funds for the investment did not come from the investor or the investor is protected from losses. See UP 10.3.1.1.1 for further information on equity investments and what constitutes "at risk."

- *Senior beneficial interests or senior debt*

ASC 810-10-55-24 states that the senior beneficial interests and senior debt instruments normally would absorb a minimal amount of a VIE's variability. However, it further states that all liabilities of a VIE may be variable interests

because a decrease in the fair value of the VIE's assets could be so great that the decrease is absorbed by all liabilities. Therefore, senior debt may be a variable interest.

- *Subordinated beneficial interests or subordinated debt*

These interests are likely variable interests because they would be expected to absorb all or a part of the expected losses of the entity.

Debt and equity financing for single power plant entities may take multiple forms, but are typically designed to absorb risk and expected losses from the entity. Therefore, almost all debt or equity holders likely are variable interest holders. See CG 2.2.3 for further information.

10.2.3.2 Lease agreements (entity is the lessee)

The evaluation of leases in UP 10.2.2.1 is focused on situations where the entity is the lessor of a facility. However, in some cases, such as a sale-leaseback transaction or a ground lease in the case of a renewable facility, the single power plant entity itself may be a lessee. Such transactions, in substance, are considered financing arrangements and should be assessed using the guidance for debt interests. Therefore, we would generally expect leases where the VIE is the lessee to be variable interests.

10.2.3.3 Management and service agreements

It is common for single power plant entities to enter into various service or management-type agreements, including:

- Operations and maintenance agreements
- Long-term service agreements for major maintenance
- Fuel-supply agreements (fee for service with a separate charge for fuel)
- Accounting and administrative service agreements
- Engineering, procurement, and construction contracts for the construction of a power plant

In accordance with ASC 810, all types of service contracts are evaluated in a similar manner. The guidance distinguishes between a service provider whose role is fiduciary in nature (such arrangements would not be variable interests) and a provider whose role is not (such arrangements may be variable interests). Under ASC 810-10-55-37, arrangements with decision makers or service providers do not represent variable interests if all of the following criteria are met:

- The fees are compensation for the service and are appropriate based on the level of effort involved.
- The decision maker or service provider (including certain related parties) do not hold other interests in the VIE that alone or in the aggregate would absorb more

than an insignificant amount of the expected losses or receive more than an insignificant amount of the expected residual returns of the VIE.

- The service agreement has terms and conditions that are customary and consistent with arm's length contracts for similar services.

We would generally expect a standard operations and maintenance, accounting and administrative, or long-term maintenance agreement with a third party to meet these criteria. However, the terms and conditions should be carefully considered. For example, if the service provider's operations and maintenance agreement is otherwise standard but includes a significant output guarantee, the arrangement would generally be considered a variable interest. In addition, there are specific considerations in evaluating contracts with related parties.

Related party interests

When evaluating whether a service agreement is a variable interest, a reporting entity should consider the interests held by related parties. An interest held by a related party that is under common control with the reporting entity would be considered a direct interest held by the reporting entity. All other related party interests would be included in the analysis based on its proportionate share of the interest. For example, a reporting entity that holds a 30% interest in a related party that has a 10% equity interest in the potential variable interest entity would include a 3% indirect equity interest in the analysis ($30\% \times 10\% = 3\%$).

10.2.3.4 Agreements to purchase green attributes

Renewable energy credits generated from a renewable energy plant may be sold to the purchaser of the power (embedded in a power purchase agreement) or may be sold separately. In determining whether all or a portion of this type of multiple-element agreement is a variable interest, reporting entities should consider the role of the RECs in the design of the entity. In addition, a reporting entity's determination of whether RECs are output from the facility will affect this analysis, because it may impact the determination of whether the power purchase agreement is a lease. See UP 7.3.2 for further information about the evaluation of RECs as output.

A reporting entity should apply the framework used in evaluating sales of energy from a renewable facility in assessing these arrangements. Figure 10-5 summarizes key considerations in evaluating whether the sale of RECs is a variable interest.

Figure 10-5**Sales of RECs: considerations for the variable interest analysis**

Type of sale	Evaluation	Considerations
Contract contains a lease — RECs are output	The sale of RECs is part of the use of the facility; no separate evaluation of the sale of RECs is required.	<ul style="list-style-type: none"> □ An operating lease qualifies for a specific exception and is not a variable interest¹ □ Capital leases are often not variable interests in the entity. Refer to discussion in UP 10.2.2.1
Contract contains a lease — RECs are not output	Sale of RECs is not part of the lease arrangement and is accounted for separately; evaluate as potential variable interest.	<ul style="list-style-type: none"> □ Fixed-price contract generally absorbs risks from the entity; likely a variable interest □ A minimum quantity guarantee should be evaluated because it may create risk; further evaluation may be required
REC sale included in a non-lease power purchase agreement	Evaluate as part of overall power purchase agreement; no separation required.	<ul style="list-style-type: none"> □ Entire contract should be evaluated as a potential variable interest
Stand-alone sale of RECs	A stand-alone REC sale may be a variable interest.	<ul style="list-style-type: none"> □ Fixed-price contract generally absorbs risks from the entity; likely a variable interest □ A minimum quantity guarantee should be evaluated because it may create risk; further evaluation may be required

¹ The REC is a lease element and is embedded in the contract as a component of the operating lease; therefore, it does not create or absorb any variability in the entity.

In general, a REC sale at a fixed price will absorb risk from the entity and will be a variable interest. However, if there is a minimum guarantee, further evaluation is required to determine whether the guarantee creates risk for the entity. See UP 10.2.2.2 for further information on evaluation considerations.

10.2.4 Joint plant arrangements

Many electric utilities have interests in a joint plant whereby two or more utilities own an undivided interest in the underlying power plant assets. Because of the structure of those arrangements (i.e., undivided interests in the assets rather than an interest in an entity), the VIE guidance generally does not apply. See UP 15.3 for further information.

10.3 Determining whether an entity is a VIE

This section addresses matters to consider when determining whether an entity is a variable interest entity subject to the VIE consolidation model.

10.3.1 Does the entity meet the definition of a VIE?

An entity is defined as a variable interest entity and is subject to consolidation if any one of the criteria described in ASC 810-10-15-14 is met. In evaluating whether single power plant entities are VIEs, project participants historically have focused on the impact of power purchase agreements and project financing. However, single power plant entities often have disproportionate profit sharing arrangements, protection for certain equity holders, or other structural considerations that may result in a conclusion that the entity is a VIE. Therefore, it is important to consider all of the criteria in ASC 810-10-15-14 when determining whether an entity is a VIE.

Figure 10-6 summarizes the definition of a VIE and describes some common single power plant entity structures that may meet one or more of the criteria.

Figure 10-6

The definition of a variable interest entity

Definition	Guidance	Common structures
ASC 810-10-15-14(a): Total equity investment at risk is not sufficient to permit the entity to finance its activities without additional subordinated financial support. (UP 10.3.1.1)	<ul style="list-style-type: none"> □ Equity interests are those that are reported as equity in the entity's financial statements. □ Equity investment at risk should be assessed to determine sufficiency. 	<ul style="list-style-type: none"> □ Entity has a power purchase agreement that is a variable interest (contract provides subordinated financial support) □ Entity has subordinated debt or other interests that represent subordinated financial support

Definition	Guidance	Common structures
<p>ASC 810-10-15-14(b): As a group, the holders of equity investment at risk lack any of the following characteristics:</p> <p>(1) The power to direct the significant activities</p> <p>(2) The obligation to absorb losses</p> <p>(3) The right to receive residual returns</p>	<ul style="list-style-type: none"> □ Applies if parties other than the equity holders at risk have power over the most significant activities of the entity. □ Criterion may be met if equity holders are protected from losses or returns are capped or guaranteed. □ Existence of kick-out or other participating rights may impact conclusion. 	<ul style="list-style-type: none"> □ Power purchase agreement provides off-taker with power over significant activities (e.g., fuel, dispatch) and protects equity holders from loss and caps their returns □ Power purchase agreement that requires off-taker to absorb losses and provides a right to benefits, with no voting rights □ Power project with put or call options at specified prices on the power plant involving a non-equity holder (such as the off-taker)
<p>ASC 810-10-15-14(c): Voting rights of equity holders are disproportionate to their obligation to absorb losses or right to benefits, and substantially all of the entity's activities are conducted on behalf of an investor that has disproportionately few voting rights.</p>	<ul style="list-style-type: none"> □ Criterion may be met if voting rights are not proportionate to the investment made and to the equity waterfall. □ Qualitative and quantitative factors should be assessed when determining whether substantially all the activities are conducted on behalf of an investor with disproportionately few voting rights. 	<ul style="list-style-type: none"> □ Partnership structures with a general partner that has voting and key decision-making powers but the initial investment was provided by limited partners (see UP 9.4 for further information about limited partnership investments)

Each of the VIE criteria is further discussed in the following sections.

10.3.1.1 *Insufficient equity at risk*

Excerpt from ASC 810-10-15-14(a)

The total equity investment (equity investments in a legal entity are interests that are required to be reported as equity in that entity's financial statements) at risk is not sufficient to permit the legal entity to finance its activities without additional subordinated financial support provided by any parties, including equity holders.

In evaluating whether an entity meets this criterion, the reporting entity should consider the equity investment at risk and whether it is sufficient. Factors to consider in performing this analysis are described below.

Equity investment at risk

Not all investments in an entity are “at risk.” To qualify as equity at risk, an investment must be accounted for as equity in the potential VIE’s financial statements. In addition, ASC 810-10-15-14(a) provides four characteristics of equity at risk:

- Participates significantly in profits and losses, regardless of voting ability
- Excludes equity interests issued in exchange for subordinated interests in other VIEs (i.e., the equity investment cannot be used to capitalize two entities at the same time)
- Excludes amounts provided to the equity investor by the entity or others involved with the entity, unless the provider is a parent, subsidiary, or affiliate of the investor within a consolidated group
- Excludes amounts financed for the equity investor (e.g., loans or guarantees) by the entity or others involved with the entity, unless the reporting entity providing the financing is a parent, subsidiary, or affiliate of the investor within a consolidated group

The parties should analyze the source of funding and the investors’ participation in income and losses of the entity to determine if an investment qualifies as at risk under this guidance.

Question 10-7

Does a funding commitment qualify as equity at risk?

PwC response

No. Commitments to fund the future operations of the entity, or promises to provide cash in the future in exchange for an equity interest (i.e., a stock subscription) are generally not considered equity under U.S. GAAP. Such amounts would not be reported as equity in the entity’s financial statements and should be excluded from the equity investment at risk. See CG 2.3.2 for further information on equity at risk.

10.3.1.1.1 Subordinated financial support

ASC 810-10-25-45 indicates that if the equity investment at risk is less than 10% of the entity’s total assets, it is not considered sufficient to allow the entity to finance its activities without additional subordinated financial support unless the amount of equity can be demonstrated to be sufficient. This rebuttable presumption does not necessarily mean that equity at risk of more than 10% is automatically deemed sufficient. No matter the amount of equity at risk, both qualitative and quantitative factors should be considered to determine whether the amount of equity investment at

risk is sufficient. One of the key considerations in making this assessment is whether subordinated financial support was required to obtain the entity's financing. The following excerpt includes the definition of subordinated financial support.

Definition from ASC 810-10-20

Subordinated Financial Support: Variable interests that will absorb some or all of a variable interest entity's (VIE's) expected losses.

Given that variable interests absorb rather than create risk, virtually any variable interest may be considered subordinated financial support. Therefore, all variable interests and contractual relationships should be assessed to determine whether they are a form of subordinated financial support. For example, a power purchase agreement that is a variable interest is generally a form of subordinated financial support, triggering a conclusion that the entity is a VIE under ASC 810-10-15-14(a). A variable interest included in an agreement that contains a lease (such as a maintenance agreement) may also be a form of subordinated financial support. Other examples may include certain subordinated or other non-investment-grade debt, funding commitments, preferred interests, and other investments that do not qualify as equity at risk.

10.3.1.2 Equity holders lack power

Excerpt from ASC 810-10-15-14(b)

As a group the holders of the equity investment at risk lack any one of the following three characteristics:

1. The power, through voting rights or similar rights, to direct the activities of a legal entity that most significantly impact the entity's economic performance. . . .
2. The obligation to absorb the expected losses of the legal entity. . . .
3. The right to receive the expected residual returns of the legal entity.

As further discussed in UP 10.4, the primary beneficiary of a VIE is the party that has the power to direct the activities of the VIE that most significantly impact its financial performance, and that also has a financial exposure that could potentially be significant to the entity (obligation to absorb losses or right to receive gains that could be significant to the VIE). Although many parties to the VIE may have significant financial exposure, only one party can meet both of these criteria. The evaluation of the equity holders at risk under ASC 810-10-15-14(b) is consistent with the approach to determining the primary beneficiary in that it considers the powers held by different parties. Consider the following simplified example.

EXAMPLE 10-1**Equity holder lacks power to direct the most significant activities**

M&H Holding Company holds all of the equity interests in Foxglove Power Company (FPC). Big Bank provides financing under a 20-year debt agreement. All capacity, electric energy, and ancillary services from the plant are sold to Rosemary Electric & Gas Company under a tolling agreement, while the steam is sold to an oil refinery. The power purchase agreement provides REG with the right to control operations and maintenance and dispatch. Steam is approximately 15% of the revenue from the plant and the power purchase agreement is not a lease. For purposes of this example, the variable interests are:

- M&H — the equity interests
- Big Bank — the debt financing
- REG — the power purchase agreement

The oil refinery also has a variable interest as a result of the steam agreement.

Analysis

M&H determines that operations and maintenance and dispatch are the activities that most significantly impact the economic performance of FPC. Therefore, M&H concludes that FPC is a VIE because the tolling agreement gives a party other than the holders of the equity at risk (i.e., REG) the power to direct FPC's most significant activities.

Kick-out rights and participating rights

One of the characteristics that results in a conclusion that an entity is a VIE is that the equity holders do not have the power to direct the activities of the entity that most significantly impact its financial performance. This power may be conveyed through kick-out or participating rights and the existence of or lack of these rights may have a different impact on the VIE analysis depending on whether the entity should be evaluated as a corporation or as a limited partnership (see CG 2.3.3.2).

Assessment for entities evaluated as corporations

If an entity should be evaluated as a corporation and a decision maker arrangement exists, the evaluation of kick-out or participating rights can be summarized in the following three steps:

1. Determine if the decision maker arrangement is a variable interest. If it is not a variable interest, the arrangement does not prevent the equity holders from having the power to direct the activities of the entity that most significantly impact its economic performance.

2. Determine if a substantive kick-out or participating right exists that can be exercised unilaterally. If a substantive right to replace the decision maker can be unilaterally exercised by one party, the equity holders as a group would not lack the power over the significant activities that impact the economic performance.
3. Assess the rights of shareholders and determine if the holders of equity at risk have the power to direct the activities of the entity that most significantly impact its economic performance.

After considering the above three steps, a decision maker that has the power over the significant activities, and that cannot be replaced through a unilateral exercise right, would cause an entity to be a VIE.

For other than decision making arrangements, if an interest holder other than the holders of equity at risk has kick out or participating rights related to the significant activities that can be unilaterally exercised, the equity holders would not have the power over those activities and the entity would be a VIE.

Excerpt from ASC 810-10-15-14(b)(1)(i) – For legal entities other than limited partnerships

If no owners hold voting rights or similar rights (such as those of a common shareholder in a corporation) over the activities of a legal entity that most significantly impact the entity's economic performance, kick-out rights or participating rights (according to their VIE definitions) held by the holders of the equity investment at risk shall not prevent interests other than the equity investment from having this characteristic unless a single equity holder (including its related parties and de facto agents) has the unilateral ability to exercise such rights. Alternatively, interests other than the equity investment at risk that provide the holders of those interests with kick-out rights or participating rights shall not prevent the equity holders from having this characteristic unless a single reporting entity (including its related parties and de facto agents) has the unilateral ability to exercise those rights. A decision maker also shall not prevent the equity holders from having this characteristic unless the fees paid to the decision maker represent a variable interest

Assessment for entities evaluated as limited partnerships

If the entity should be viewed as a limited partnership, the reporting entity should determine whether the limited partners lack the power to direct the entity's most significant activities as discussed in ASC 810-10-15-14(b)(1)(ii). In performing this analysis only rights that are substantive should be considered.

Excerpt from ASC 810-10-15-14(b)(1)(ii) – For limited partnerships

Partners lack the power through voting rights or similar rights, to direct the activities of a legal entity that most significantly impact the entity's economic performance if neither of the below conditions exist;

- (1) a simple majority or lower threshold of limited partners (including a single limited partner) with equity at risk is able to exercise substantive kick-out rights (according to their voting interest entity definition) through voting interests over the general partner(s), and
- (2) Limited partners with equity at risk are able to exercise substantive participating rights (according to their voting interest entity definition) over the general partner(s).

If the limited partners do not hold kick-out rights that can be exercised through a simple majority vote or lower, or do not have substantive participating rights, the equity holders as a group would not have the power to direct the significant activities of the entity that impact economic performance and the entity would be a VIE.

Impact of protective rights**Partial definition from ASC 810-10-20**

Protective Rights: Rights designed to protect the interests of the party holding those rights without giving that party a controlling financial interest in the entity to which they relate.

The inclusion of protective rights in an agreement does not impact the analysis of whether an entity is a VIE in the same way as kick-out or participating rights. Protective rights are common in project financing agreements and in long-term power purchase agreements, which often include provisions allowing the debt holder or power off-taker to assume operational responsibility for the plant if the operator defaults. Rights that are exercisable only in the event of default are protective rights and would not trigger the conclusion that an entity is a VIE. The definition in ASC 810-10-20 includes examples of protective rights as follows:

- Approval or veto rights that do not affect the activities that most significantly impact the entity's economic performance. Protective rights often apply to fundamental changes in the entity's activities, such as: (1) sale of important assets or activities that change the credit profile of the entity; or (2) capital expenditures over a certain limit or the issuance of new equity or debt.
- The ability to remove the primary beneficiary in cases such as bankruptcy or breach of contract.

- Limitations on operating activities that may restrict certain activities but do not provide a controlling financial interest (such as rights held by a franchisor over activities of a franchisee).

These concepts are further illustrated in the following simplified examples.

EXAMPLE 10-2

Protective kick-out rights

Assume the same facts as in Example 10-1. However, M&H Holding Company has the responsibility to obtain fuel for Foxglove Power Company and it also controls operations and maintenance (as opposed to Rosemary Electric & Gas Company). M&H concludes that fuel procurement and operations and maintenance are the most significant activities affecting the potential profit or loss of FPC. As a result of this change, further assessment is required to determine whether FPC is a VIE.

The power purchase agreement provides REG with the right to assume operational responsibility for the facility in the event of a default under the contract. M&H considers how this right impacts the evaluation of whether FPC is a VIE.

Analysis

REG's ability to remove M&H in the event of a default under the contract is an example of a protective right and does not impact the evaluation of whether FPC is a VIE. The parties should further assess whether FPC is a VIE under one of the other provisions of ASC 810-10-15-14.

EXAMPLE 10-3

Operational kick-out rights

Assume the same facts as in Example 10-2, however, the power plant is held in a partnership entity, Foxglove Power Partners (FPP). M&H Holding Company holds a 2% general partnership interest and manages the day-to-day operations of the plant. FPP has class A limited partnership interests held by three limited partners. It also has class B limited partnership shares held by one limited partner. The class B shares are mandatorily redeemable and are accounted for as a liability by FPP. As such, the class B shares are not considered equity at risk because the interest is not classified as equity by FPP.

The limited partners provided their own equity and together have approval over all major operating decisions, including financing, the annual budget, operations and maintenance schedules, and major contracts. In addition, they have the ability to rescind the general partner's management agreement (without cause) through a simple majority vote.

Analysis

As discussed in CG 2.3.3.2, in this case, since the entity is a partnership and functions like a partnership, the limited partners would need to hold substantive kick-out rights

for the entity to not be a VIE under ASC 810-10-15-14(b)(1). Substantive kick-out rights exist and can be exercised by a simple majority vote or lower threshold. Therefore, the criteria under ASC 810-10-15-14(b)(1) are not met (although the partners also need to consider whether FPP is a VIE under one of the other provisions of ASC 810-10-15-14). However, if the rights were held by only the limited partner with the mandatorily redeemable shares such that it had the ability to act unilaterally, FPP would be a VIE.

Obligation to absorb losses/right to receive returns

In accordance with ASC 810-10-15-14(b)(2) and (b)(3), an entity also meets the definition of a VIE if the equity holders lack the obligation to absorb expected losses or the right to receive the expected residual returns of the entity. When evaluating these provisions, a reporting entity should consider:

- Expected losses — consider whether the equity holders as a group are required to absorb the entity’s expected losses on a “first-dollar loss” basis until the equity is depleted. In other words, there should not be a mechanism or arrangement that protects the equity holders from losses on their investment.
- Expected residual returns — an entity is a VIE if the equity investors’ return is capped or other variable interest holders share in the residual cash flows at an amount that is considered significant relative to the level of expected residual returns.

Sample features that may trigger VIE accounting under this guidance include:

- A guarantee on returns of an equity investment by the entity itself, or by other parties that are involved with the entity, that provides the equity holder with protection against losses (e.g., a return on investment may be guaranteed for tax-equity holders in a renewable energy “flip” structure, when the investment is equity under U.S. GAAP)
- A residual value guarantee that provides the equity holders with protection against losses (e.g., a plant lessee guarantees a specified power plant value at the end of the power purchase agreement)
- A put option held by the entity at a specified price that provides the equity holder with protection against losses (e.g., the entity holds an option to put the power plant to the off-taker at some point during or at the end of the power purchase agreement at a specified price)
- A call option written by the entity may function to limit the equity holders’ right to receive residual profits (e.g., if the power plant can be called by the off-taker at some point during or at the end of the power purchase agreement at a specified price)

- An arrangement whereby the power plant off-taker shares in profits from sales of other by-products by the entity, thereby capping the equity holders' ability to earn returns

Some of these arrangements may also trigger VIE accounting under ASC 810-10-15-14(a) because they may provide subordinated financial support or indicate the equity investment was not at risk.

10.3.1.3 Nonsubstantive voting rights

Excerpt from ASC 810-10-15-14(c)

The equity investors as a group also are considered to lack the characteristic in (b)(1) if both of the following conditions are present:

1. The voting rights of some investors are not proportional to their obligations to absorb the expected losses of the legal entity, their rights to receive the expected residual returns of the legal entity, or both.
2. Substantially all of the legal entity's activities . . . either involve or are conducted on behalf of an investor that has disproportionately few voting rights.

This criterion is intended to identify entities that are structured so that a reporting entity can avoid consolidation under the voting interest model by providing nonsubstantive voting rights to another party. Examples of structures that may trigger VIE accounting under this provision include:

- A partnership structure that provides the general partner with all of the voting and key decision-making powers while the initial investment was provided by the limited partnership interests
- A partnership arrangement whereby two partners each provide initial equity of 50% and retain 50% voting rights; however, the profit sharing is disproportionate (e.g., one party receives 90% of profits after the initial investment is repaid)

In such cases, reporting entities need to consider whether the activities are being conducted on behalf of the party with disproportionately fewer voting rights. See CG 2.3.3 for further information.

10.3.2 Reconsideration of whether an entity is a variable interest entity

Under the VIE consolidation model, a reporting entity is required to assess whether it is involved with a VIE on the date that it initially becomes involved with an entity. In addition, ASC 810-10-35-4 requires reconsideration of the initial determination of whether an entity is a VIE in response to certain events:

- Governing documents or contractual arrangements are modified, resulting in a change in the characteristics or adequacy of the equity at risk.

- All or part of the equity is returned to the equity holders and other investors become exposed to expected losses.
- The entity adds new activities or assets that increase expected losses, or curtails or modifies activities to decrease expected losses.
- The entity receives additional equity that is at risk.
- The equity holders as a group lose the power to direct the activities of the entity that most significantly impact its economic performance.

Financing and operational adjustments over the life of a single power plant entity may result in certain entities changing between the VIE accounting model and the voting interest model. For example, reconsideration triggers for single power plant entities include expiration of a power purchase agreement or pay-off of project financing. In some cases, these events may cause the reporting entity to conclude that the entity is no longer a VIE.

In addition, the guidance specifically states that losses in excess of expected losses would not result in a reconsideration event.

10.3.3 Does a scope exception apply?

Prior to concluding that it is involved in a variable interest entity, a reporting entity should consider whether one of the ASC 810 scope exceptions is applicable. Entities that qualify for one of the exceptions in ASC 810-10-15-12 or 15-17 are not subject to the VIE consolidation model.

Figure 10-7 Exceptions to the VIE consolidation model

ASC 810-10-15-12 and 15-17 provides the following scope exceptions:

- Not-for-profit organizations, unless used in a manner similar to a VIE to circumvent the requirements of the VIE consolidation model
- Employee benefit plans
- Investments accounted for at fair value in accordance with specialized guidance in the AICPA Audit and Accounting Guide, *Investment Companies*
- Separate accounts of life insurance companies
- Grandfathered entities with an “information out” exception
- Entities qualifying for the business scope exception
- Governmental organizations

The VIE consolidation model does not apply if an entity qualifies for one of these scope exceptions.

The last three exceptions included above are the most commonly considered when evaluating single power plant entities. Key considerations in applying these exceptions are further discussed below.

10.3.3.1 “Information out”

ASC 810-10-15-17(c) provides a scope exception for VIEs created prior to December 31, 2003, where the reporting entity is unable to obtain sufficient information to make a VIE assessment or to perform the related accounting, after making an exhaustive effort. This exception applies as long as the reporting entity is unable to obtain the necessary information. However, the assertion that it is unable to obtain the information should be validated on a regular basis. In addition, any significant change in the entity’s contractual or other arrangements (e.g., negotiation of a new power purchase agreement) would generally preclude continued use of this exception because contract changes should permit incorporation of provisions that allow access to necessary information.

In addition, ASC 810-10-50-16 requires a reporting entity applying this exception to make certain specific disclosures. See FSP 18 for further information about the applicable disclosure requirements.

10.3.3.2 The “so-called” business scope exception

The VIE consolidation model provides a scope exception for entities that meet the definition of a business under ASC 805. Many single power plant entities may appear to qualify for this exception. However, the conditions for this exception are difficult to meet in practice. ASC 810-10-15-17(d) prohibits a reporting entity from using the business scope exception in any of the following situations:

- The reporting entity (including related parties) participated significantly in the design or re-design of the entity, unless the entity is a joint venture under joint control of the reporting entity and one or more third parties
- The entity is designed so that substantially all of its activities involve or are conducted on behalf of the reporting entity (including related parties)
- The reporting entity (including related parties) provides more than half of the total of the equity, subordinated debt, and other forms of subordinated financial support to the entity
- The activities of the entity are primarily related to securitizations or other forms of asset-backed financings or single-lessee leasing arrangements

These additional requirements severely limit the circumstances in which the business scope exception may be applied. See CG 2.1.2.4 for further information.

Considerations in applying this exception to single power plant entities include:

Is the entity a business under ASC 805?

Reporting entities should first assess whether the variable interest entity meets the definition of a business. If the reporting entity concludes that the potential VIE is a business, it should then evaluate whether it meets any of the exceptions to ASC 810-10-15-17(d) as discussed below. See UP 8.2 for information on assessing whether a single power plant entity meets the definition of a business, including specific considerations for an entity in the development stage.

Is the entity a single-lessee entity, or are its activities a form of asset-backed financing?

Single power plant entities are usually structured with one or more equity investors, a debt investor or other source of additional financing and, in many cases, a power purchaser. In a typical single power plant entity, the project debt is collateralized with the assets of the entity and is non-recourse to the equity owners. In such cases, this debt is considered to be a key element of the design, and the activities of the entity would be considered to be a form of asset-backed financing; thus, the business scope exception cannot be applied.

In other cases, the power purchase agreement qualifies as a lease in accordance with ASC 840. Single-lessee entities are also precluded from applying the business scope exception under ASC 810-10-15-17(d)(4).

What is the reporting entity's involvement with the entity?

If the entity is a business and it is not involved in asset-backed financing or single-lessee arrangements, the reporting entity should assess its other involvement with the entity. The business scope exception is not applicable if the reporting entity (or its related parties) participated substantially in the design of the entity, if the entity's activities are substantially for the reporting entity, or if the reporting entity provides more than half of the entity's financial support. For many single power plant entities, this will also preclude application of the business scope exception because the interest holders participated in the design of the entity and/or the purpose and design of the entity are primarily for the reporting entity.

Question 10-8

Is the business scope exception ever applicable to a single power plant entity?

PwC response

Generally, no. As discussed above, there are significant limitations to the application of the business scope exception. As a result, we would rarely expect the business scope exception to be applied to single power plant entities. The exception may be applicable to entities holding multiple power plants, but only if the reporting entity was not involved in the design of the entities and the activities of the entities are not performed on the reporting entity's behalf.

10.3.3.3 Governmental organizations

In most cases, a reporting entity otherwise required to apply the VIE consolidation model should not consolidate a governmental organization or a financing entity established by a governmental organization. The term “governmental organization” is defined in the AICPA Audit and Accounting Guide, *State and Local Governments*. Because of the prevalence of public power organizations, reporting entities may become involved in contractual arrangements with governmental organizations. In such cases, the reporting entity should consider whether this exception is applicable. See CG 1.3.3.3 for additional discussion on governmental organizations.

10.4 Identifying the primary beneficiary

10.4.1 The primary beneficiary model

Under ASC 810, the determination of the primary beneficiary focuses on control of the activities of the VIE that most significantly impact its economic performance. The approach requires judgment in the determination of the primary beneficiary and, as a result, who consolidates the VIE.

10.4.1.1 Definition of the primary beneficiary

Excerpt from ASC 810-10-25-38A

A reporting entity shall be deemed to have a controlling financial interest in a VIE if it has both of the following characteristics:

- a. The power to direct the activities of a VIE that most significantly impact the VIE’s economic performance
- b. The obligation to absorb losses of the VIE that could potentially be significant to the VIE or the right to receive benefits from the VIE that could potentially be significant to the VIE.

ASC 810 is specific that only one party can have the power to direct the most significant activities of a variable interest entity. In practice, this is typically the key factor that determines the primary beneficiary as it would be rare for a variable interest holder not to have a potentially significant financial interest in the VIE.

ASC 810-10-25-38B through 25-38G provide further guidance on the approach to evaluating which party has the characteristics of the primary beneficiary as summarized in Figure 10-8.

Figure 10-8

Factors in determining the primary beneficiary

Most significant activities (ASC 810-10-25-38B)

The identification of the most important activities of the VIE and who has the power to direct those activities (irrespective of whether those powers are exercised) is the pivotal factor in the analysis.

Kick-out rights and participating rights (ASC 810-10-25-38C)

Unilateral kick-out rights and participating rights may affect the determination of who has the power to direct the most significant activities. However, protective rights held by others do not preclude a variable interest holder from being the primary beneficiary.

Shared power (ASC 810-10-25-38D)

If power is shared among multiple unrelated parties, then no party is the primary beneficiary. Shared power requires consent of the parties for significant decisions. If power is not shared, but the most significant activities are directed by multiple unrelated parties and the nature of the activities is the same, then the party with the power over a majority of the activities has the power to direct.

Power over different activities (ASC 810-10-25-38E)

If the most significant activities are directed by multiple unrelated parties and the nature of the activities is different, then the party with the power to direct the activities that most significantly impact the economic performance of the VIE has the power to direct. It is expected that only one party will have that power.

Involvement in design of the VIE (ASC 810-10-25-38F)

Significant involvement in the initial design of a VIE does not automatically provide a reporting entity with the power to direct the most significant activities. However, that involvement may indicate that the reporting entity was provided the opportunity to establish arrangements giving it that power.

Disproportionate economics (ASC 810-10-25-38G)

If a reporting entity has economic interests in a VIE that are disproportionately greater than its stated power to direct the significant activities, the level of economic interest may indicate the amount of power actually held by the reporting entity.

Each of these factors is discussed in the following sections.

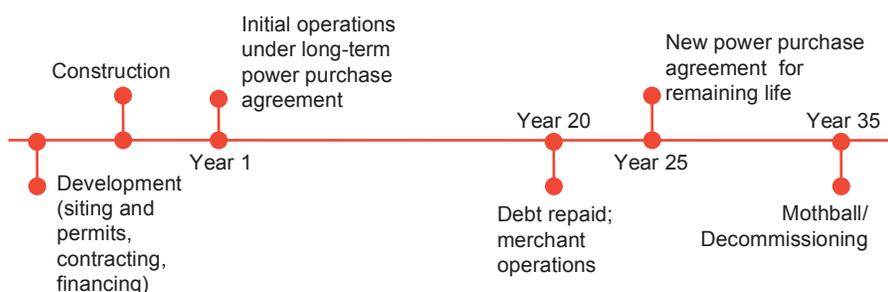
10.4.1.2 Most significant activities

ASC 810-10-25-38B

A reporting entity must identify which activities most significantly impact the VIE's economic performance and determine whether it has the power to direct those activities. A reporting entity's ability to direct the activities of an entity when circumstances arise or events happen constitutes power if that ability relates to the activities that most significantly impact the economic performance of the VIE. A reporting entity does not have to exercise its power in order to have power to direct the activities of a VIE.

The primary beneficiary of a VIE is the variable interest holder with the power to direct the activities of the VIE that most significantly impact the VIE's economic performance. The significant activities of a single power plant entity evolve and mature over the life of the power plant and, as a result, the party controlling those activities may also change over time. The life cycle of a typical power plant is depicted in Figure 10-9:

Figure 10-9
Typical power plant life cycle



The primary beneficiary should also have a significant financial interest; however, this is not typically a key consideration because most variable interest holders will meet this criterion. Multiple parties may have potentially significant financial interests, but only one party can have the power to direct the most significant activities. Therefore, the identification of the most significant activities impacting the economic performance of the entity and evaluation of who controls these activities are critical steps in the determination of the primary beneficiary.

A single power plant entity is engaged in different activities over its life cycle (i.e., the activities are generally linear), and each significant activity is contingent on the prior significant activity. As a result, a reporting entity's evaluation of which activities are most significant should focus on the uncertainty of completing each stage as well as the activities in each stage that will most significantly impact the economic performance of the entity. If there is uncertainty that the entity will achieve the next stage of its operations, usually only the significant activities in the current phase are considered. However, once the uncertainty regarding achieving progress to additional

phases has lapsed, the reporting entity should evaluate which powers are most significant considering the remaining life cycle of the entity.

Once the reporting entity identifies which activities most significantly impact the economic performance of the VIE, it should determine which party controls these activities. Contractual arrangements often dictate which party, if any, has the power to direct activities that are most significant to the economic performance of a VIE. In completing this analysis, a shift in which party holds a specific power as a result of changes in contractual arrangements or counterparties should not be considered until those changes are in effect. This analysis may result in changes in the primary beneficiary over the life cycle as control of significant activities moves among the parties involved with the power plant and the VIE. For example, a purchase option embedded in an operations and maintenance agreement might lead to a change in the party with control, but the party with the option is not deemed to have control until the point at which the option is exercised. However, a reporting entity can anticipate how those changes are likely to impact the primary beneficiary conclusion and should make sufficient disclosures for potential material changes in the future. Figure 10-10 provides a summary of activities that may require consideration in determining the significant activities over the life of a typical power plant.

Figure 10-10
Significant activities during a power plant's life cycle

Typical activities	Evaluation points
Development stage	
<ul style="list-style-type: none"> □ Siting and permitting may impact future profitability (location may impact dispatch, success of renewable plant) □ Financing may be obtained during this stage; the entity frequently depends on a long-term power purchase agreement □ Strategy may involve decisions on investment, future development, supply, and energy production 	<ul style="list-style-type: none"> □ Key strategic decisions (e.g., location, type of power plant, technology) are likely to have the most significant impact during this stage □ During development, control is typically retained by the equity holders □ Due to significant inherent uncertainty, prior to the start of construction the determination of the primary beneficiary usually focuses on powers held during this stage

Typical activities	Evaluation points
Construction stage	
<ul style="list-style-type: none"> □ Construction is the primary activity during this phase; completion of construction may be a condition for the activation of other operating agreements 	<ul style="list-style-type: none"> □ The EPC contractor and developer are likely actively involved in oversight of construction; an EPC contract may absorb risks associated with the entity through completion of this phase □ A power purchase agreement or debt arrangement may include protective rights that would not impact the evaluation □ Once construction commences, there is generally a high degree of certainty that the entity is viable. See the response to Question 10-9 for discussion of primary beneficiary.
Operations stage	
<ul style="list-style-type: none"> □ Operations and maintenance activities are essential for the power plant to dispatch and earn a profit; may be substituted among different service providers for most types of power plants □ Power plant dispatch, when combined with control over fuel supply, may dominate economic performance for certain power plants □ Fuel strategy may significantly influence power plant economic performance (e.g., storage, hedging, pricing) 	<ul style="list-style-type: none"> □ Multiple parties may share power over different activities □ Although parties holding the power may shift in the future (e.g., operations and maintenance provider will change), the evaluation usually focuses on which party currently holds the powers □ Evaluation of relative importance of various activities may be supported by quantitative analysis, if necessary □ Lease arrangements may impact the determination of which activities are significant (i.e., the existence of a lease may mean that fuel and dispatch risks are designed out of the entity)
Post-operation/ decommissioning	
<ul style="list-style-type: none"> □ Strategy of managing the power plant post-commercial operation □ Dismantling the power plant can be complex, depending upon the type of generation □ Asset retirement obligations must be satisfied 	<ul style="list-style-type: none"> □ Equity holders are likely the primary party involved at this stage

The evaluation points in Figure 10-10 are based on typical activities and common contractual arrangements. A reporting entity should consider its specific facts and circumstances in completing the primary beneficiary analysis.

Question 10-9

How do changes in significant activities over the life of the power plant impact the primary beneficiary determination?

PwC response

The significant activities of a single power plant entity during its life cycle are generally sequential: beginning with development, then construction, followed by operations, with a final wind-down and decommissioning. In evaluating the relative significance of the powers during each stage, the parties should focus on the purpose and design of the entity, the significance of the activities throughout the life of the entity, the ability of the variable interest holders to impact the completion of each phase, and the likelihood the phases will be successful.

Factors to consider include:

□ *Development*

Significant uncertainty is often present during the development stage while the entity identifies a location, obtains permits and financing, and potentially contracts for output of the plant. All other activities of the plant (construction and operation) are contingent on the completion of development, and entities do not always advance beyond this stage. Due to this uncertainty, the parties would generally conclude that the power to control strategy and development, as well as arranging financing, are the most important powers during this stage of the life cycle.

□ *Construction*

Once the entity has obtained all required permits and financing and has executed a construction contract, there is generally a high degree of certainty that the power plant will be completed and that operations will commence. As such, in evaluating the most significant activities during this stage, the parties may consider the powers that will impact economic performance over the entire remaining life cycle of the power plant. This may lead to the conclusion that the powers held during the operations phase are more significant than the powers during construction. Note that this conclusion may change if there is more uncertainty during construction (e.g., experimental technology) or if there is uncertainty about the operations phase (e.g., power contracts, operations and maintenance agreements, or other service contracts are not yet executed). Any uncertainty about successful completion of the project would lead to a focus on construction activities only in completing the evaluation during this stage.

□ *Operations*

The key activities identified during the operations phase will often have the most significant overall impact on the economic performance of the entity over its life-cycle (once uncertainty about reaching the construction phase has been resolved). Therefore, once there is a high level of assurance that construction will be

achieved, the evaluation generally focuses on which parties control key operating decisions. See UP 10.6 for examples of application of by-design in the evaluation of potential variable interests in a single power plant entity.

The consideration of who controls the significant activities is judgmental, and specific facts and circumstances can result in different conclusions. Factors that may influence the conclusion are discussed in the following sections.

Question 10-10

Does contract length factor into the evaluation of the primary beneficiary?

PwC response

Generally, no. When considering a contract that is a variable interest, the term of the contract is generally not important to the holder's power relative to the VIE. Holding powers provided by the contract for a longer period should therefore not impact the conclusion as to which party is the primary beneficiary.

Thus, in general, we do not believe that contract length is a defining factor in determining which variable interest holder controls activities that are most significant to the entity. As discussed above, once development is completed and construction begins, the evaluation is typically focused on which party holds the most significant powers during the operations phase (unless there is significant uncertainty regarding construction). If the party holding those powers shifts over time, the primary beneficiary analysis is performed based on who has the power to direct the most significant activities as of the reporting date, without incorporating the impact of expected future contractual changes (e.g., expiration of certain contractual arrangements). Therefore, the length of a contract would not impact this analysis. However, in some cases contract length may impact the determination of whether a contract is a variable interest (see the response to Question 10-6).

10.4.1.3 Kick-out and participating rights

Excerpt from ASC 810-10-25-38C

A reporting entity's determination of whether it has the power to direct the activities of a VIE that most significantly impact the VIE's economic performance shall not be affected by the existence of kick-out rights or participating rights unless a single reporting entity (including its related parties and de facto agents) has the unilateral ability to exercise those kick-out rights or participating rights. . . . Protective rights held by other parties do not preclude a reporting entity from having the power to direct the activities of a variable interest entity that most significantly impact the entity's economic performance.

As discussed in UP 10.3.1.2, power purchase agreements and debt agreements common in single power plant entity structures generally do not incorporate kick-out rights or other participating rights. However, these contracts frequently include protective rights that may be exercised only in the event of default. As noted in ASC

810-10-25-38C, the presence of protective rights does not preclude another party from having a particular power. The impact of protective rights needs to be considered only in the event the rights are exercised, which may result in a change in control.

Even though kick-out and participating rights are not common in power purchase or financing agreements, other agreements (such as equity agreements) may include them. Therefore, the terms of all significant contractual arrangements and the rights of all parties involved should be considered when determining which party is the primary beneficiary. Although one party may appear to have control over the most significant activities of the VIE, the existence of kick-out or participating rights that may be exercised unilaterally will likely change that conclusion.

10.4.1.4 *Shared activities*

Excerpt from ASC 810-10-25-38D

If a reporting entity determines that power is, in fact, shared among multiple unrelated parties such that no one party has the power to direct the activities of a VIE that most significantly impact the VIE's economic performance, then no party is the primary beneficiary. Power is shared if two or more unrelated parties together have the power to direct the activities of a VIE that most significantly impact the VIE's economic performance and if decisions about those activities require the consent of each of the parties sharing power.

For some VIEs, the number of significant activities may be limited and the analysis of which party has control may be fairly straightforward. However, this is generally not the case when evaluating a single power plant entity where multiple parties direct different activities. ASC 810 contemplates that power may be shared among multiple parties, including cases where power over the same activities is shared or where different parties control different activities. There is no primary beneficiary if no one party controls the significant activities. As illustrated in Figure 10-11, the determination of which party controls the activities that have the most significant impact over economic performance can be complex when activities are shared in various ways.

Figure 10-11
Shared activities

Structure	Evaluation
Power is shared among multiple unrelated parties such that no one party has the power to direct.	There is no primary beneficiary (power is shared if more than one party must agree).
Activities are directed by multiple unrelated parties and the nature of those activities is different.	The primary beneficiary is the party that directs the activities that most significantly impact economic performance. See UP 10.4.1.5.

Structure	Evaluation
Activities are directed by multiple unrelated parties and the nature of those activities is the same.	The primary beneficiary is the party with the power over the majority of activities.

In a single power plant entity, it is not typical for multiple parties to direct activities of the same nature, so that scenario is not further discussed in this chapter. However, there can be circumstances where power over certain activities is shared or where multiple parties direct activities of a different nature, as discussed below.

Power is shared

If two or more unrelated parties have the power to direct the significant activities of a VIE, such that no single party has the power to direct those activities alone, power is considered to be shared, and the VIE would not have a primary beneficiary. Such circumstances may be present in a joint venture arrangement.

Joint ventures, by definition, are separate and specific businesses for the mutual benefit of their members. Because a joint venture usually involves an arrangement through which each member may participate, directly or indirectly, in the overall management, consent of all members is required on decisions impacting the joint venture's economic performance. In the power and utility industry, power plant joint ventures (e.g., renewable energy projects, coal power plants) typically include many operational, financial, and strategic decisions that are shared by the parties to the arrangement through a management committee or similar structure.

For power to be shared in a joint venture or other arrangement, all key decisions must require mutual consent. If significant activities are not controlled by mutual consent, further analysis to determine the primary beneficiary will be required. For example, if a power project with two members includes six important decisions and each individual member has exclusive discretion over three of those decisions, that would not be considered shared control. Determination instead must be made as to which of the important decisions grants one member power to direct the most significant activities. See UP 10.4.1.5.

Question 10-11

Is power considered shared if there is a management committee responsible for strategic direction and other decision making?

PwC response

It depends. Power plant joint ventures and other single power plant entities often include a management committee or similar organization as part of the decision-making process. In some cases, power is shared because all significant (participating) decisions require consent of a representative from each party. However, in other situations, one party may effectively control because it has responsibility for day-to-day decisions and ongoing execution. Control may also be vested with only one of the

parties if decisions requiring consent of one or more members of the committee are protective in nature, or if one of the parties has veto rights over significant decisions.

As such, joint decision making as part of the overall corporate governance function does not automatically result in a conclusion that power is shared. In evaluating the impact of this type of shared power on control of the significant activities of a VIE, reporting entities should carefully evaluate the nature of the powers held by the management committee. See CG 3.4 for further information about evaluating protective versus participating rights.

10.4.1.5 *Multiple parties control different activities*

ASC 810-10-25-38E

If the activities that impact the VIE's economic performance are directed by multiple unrelated parties, and the nature of the activities that each party is directing is not the same, then a reporting entity shall identify which party has the power to direct the activities that most significantly impact the VIE's economic performance. One party will have this power, and that party shall be deemed to have the [power to direct the activities of a VIE that most significantly impact the VIE's economic performance].

In many single power plant entity VIEs, control of significant operational factors is dispersed among different parties. For example, it is common for the operator to control operations and maintenance while the off-taker controls fuel and dispatch. In such cases, factors to consider in determining which of the activities is most significant include:

- *Is the power purchase agreement a lease?*

If so, the substance of the arrangement is the use of property and risks associated with the inputs (e.g., fuel) and outputs from the plant (e.g., energy and capacity) are generally considered to be outside the design of the VIE. However, in some cases, the VIE may retain fuel risk or may have responsibilities for related activities, such as operations and maintenance, through a service contract or in some other form within the structure of the lease arrangement. In those cases, an analysis of which activities is most significant should be performed.

- *What is the expected financial impact of the activity? What is the relative impact compared with other significant activities?*

For example, if capacity payments (which are dependent on operations and maintenance) are expected to be \$40 million per month, and payments for energy (based on dispatch) are expected to range from \$10 million to \$20 million per month, the parties may conclude that operations and maintenance activities are more important.

- *Is there a wide range of possible economic outcomes (suggesting control may be more important in influencing economic performance) or are all potential outcomes within a narrow range?*

For example, a decision to lock in the cost of fuel supply or float with the market when the power plant has a fixed-price power purchase agreement may have a wide range of possible outcomes, with differing and significant impacts on financial performance.

- *Are there related party relationships?*

As further discussed below, power controlled by related parties may need to be considered as a group.

- *Have all significant activities been appropriately considered?*

Depending on contractual arrangements, once a power plant is in operation, fuel supply, dispatch, and operations and maintenance will likely be important activities. A review of the risks identified in the evaluation of design will be helpful in determining the most significant activities.

The list above provides some of the factors that should be considered in determining which activity is most significant. See CG 2.4.2.2 for further information on factors to consider in evaluating which activities most significantly impact economic performance.

Question 10-12

How should reporting entities consider operations and maintenance given the potentially pervasive impact on economic performance?

PwC response

For an operating power plant, the operations and maintenance function is one of the primary activities with a significant impact on the VIE's economic performance. Considerations in evaluating its impact include:

- Operations and maintenance activities are a basic requirement to keep the power plant running. Poor execution by the party responsible for operations and maintenance may lead to subpar plant performance (e.g., high heat rate, lower than expected availability) and in a worst case scenario, plant shut-down. This may have a significant negative impact on the entity's economic results.
- Operations and maintenance activities may not be complex, and for some power plant types are easily duplicated or outsourced, and/or are available from multiple service providers. However, the right or responsibility to perform this function provides the responsible party with a high degree of control.
- Although operations and maintenance activities directly impact the power plant's availability (and thus the level of capacity payments, if any), there is a relatively narrow expected outcome that results from the activities. That is, superior operations and maintenance services would be expected to impact results only minimally compared with services that are at a satisfactory level. In contrast, exceptional management of dispatch or fuel may have a more meaningful impact on the overall economic results.

In considering the importance of operations and maintenance, one view is that operations and maintenance is a defining factor because of its baseline impact on a power plant's economic performance—without strong operations and maintenance activities there will be no other operations. However, operations and maintenance performance may be relatively easily achieved, and thus have minimal impact on the expected variability of the plant's economic performance. In such cases, the overall strategy of a plant, including decisions such as contracting, dispatch, and fuel supply, may have a more significant impact on the incremental profitability of the plant's operations.

We would generally expect that control of operations and maintenance, whether directly or through the ability to determine the operations and maintenance provider, will be a key factor in the primary beneficiary conclusion. However, a final determination in each case will be based on the facts and circumstances of the single power plant entity. For example, the nature and type of power plant (fossil versus renewable, contracted versus merchant, base load versus peaker) as well as the type of and specifics within the contractual arrangement(s) involved, may impact the analysis.

10.4.1.6 *Involvement in design*

Excerpt from ASC 810-10-25-38F

Although a reporting entity may be significantly involved with the design of a VIE, that involvement does not, in isolation, establish that reporting entity as the entity with the power to direct the activities that most significantly impact the economic performance of the VIE. However, that involvement may indicate that the reporting entity had the opportunity and the incentive to establish arrangements that result in the reporting entity being the variable interest holder with that power.

ASC 810-10-25-38F states that reporting entities should consider whether they (or another party) have been significantly involved with the initial design of the VIE and whether that involvement conveys the power to direct the most significant activities. Involvement in the initial design may provide the reporting entity with the ability to structure the entity to provide it with the power over the most significant activities. For example, the initial developer of a power plant project may ensure that it retains control over key performance determinants when executing financing and other arrangements.

10.4.1.7 *Disproportionate economics*

Excerpt from ASC 810-10-25-38G

Consideration shall be given to situations in which a reporting entity's economic interest in a VIE . . . is disproportionately greater than its stated power to direct the activities of a VIE that most significantly impact the VIE's economic performance. Although this factor is not intended to be determinative in identifying a primary beneficiary, the level of a reporting entity's economic interest may be indicative of the amount of power that reporting entity holds.

In accordance with ASC 810-10-25-38G, reporting entities should consider economic interests as another factor in the evaluation of the primary beneficiary; this has been an area of SEC staff focus. A significant economic interest may be an indication of the amount of power held by a variable interest holder, even in cases where its stated powers to direct significant activities are less. When evaluating single power plant entities and the powers held by variable interest holders, reporting entities should be cautious in situations where a party that has significant economic interests does not also hold the power to direct the most significant activities. This provision is similar to the requirement to assess whether the economics are disproportionate in the determination of whether there is a VIE, as discussed in ASC 810-10-15-14(c).

10.4.2 Related parties

A reporting entity must first determine whether it meets the power and losses/benefits criteria on a stand-alone basis. Only if the reporting entity does not meet both criteria on a stand-alone basis should it consider other variable interests held by its related parties or consider whether it is part of a related party group that collectively meets both characteristics of a primary beneficiary.

If the related party group has both characteristics of a primary beneficiary and either power over the significant activities is shared within the related party group or the related party group is under common control, then the “related party tiebreaker” test should be performed to identify the variable interest holder within that related party group that is “most closely associated” with the VIE. The party that is most closely associated with the VIE should consolidate the VIE. Refer to CG 2.4.7 for guidance on the application of the related party tiebreaker.

If a single party within a related party group has unilateral power, and the related party group is not under common control, then the related party tiebreaker would not apply. However, if “substantially all” of the VIE’s activities involve or are conducted on behalf of any party within that related party group that meets both characteristics of a primary beneficiary (excluding the single decision maker), then the party that has the activities conducted on its behalf is required to consolidate the VIE. This requirement is intended to prevent abuse (i.e., “vote parking” arrangements) where the decision maker’s level of economics is not consistent with its stated power.

Single power plant entities may involve multiple related parties (e.g., equity holder, operations and maintenance service provider, construction contractor, energy trading company). In such cases, the reporting entity should carefully evaluate the related party relationships, especially for the stand-alone financial statements of the subsidiaries or related parties involved.

10.4.3 Ongoing reconsideration of the primary beneficiary

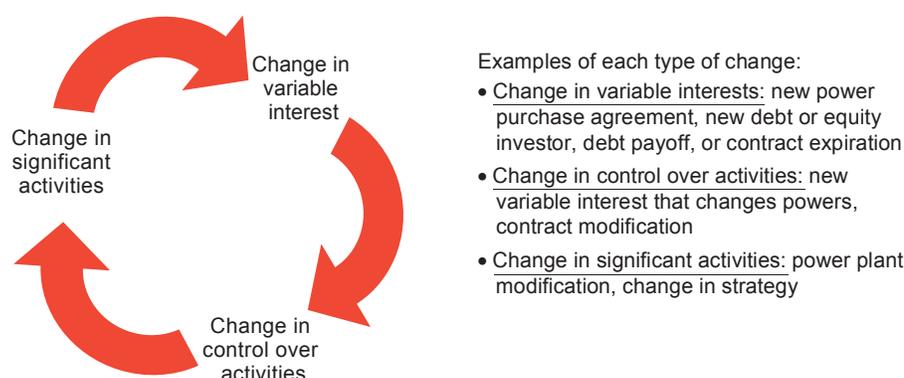
In accordance with the guidance in ASC 810, reporting entities should perform the primary beneficiary assessment on a recurring basis, including an ongoing determination of who has the power to direct the most significant activities of the entity. In adopting this guidance, the FASB acknowledged that the primary beneficiary of an entity may change over time and concluded that the requirement for ongoing assessments will provide users of the financial statements with more relevant and

reliable information. The potential triggers for a change in the primary beneficiary include a change in significant activities, a change in who has control over those activities, and any new variable interests. Examples of these types of changes are depicted in Figure 10-12.

The requirement to reassess the primary beneficiary each reporting period may be a challenge for reporting entities, especially those involved with multiple VIEs. However, in most cases, as part of the initial VIE evaluation, the reporting entity should be able to identify potential triggers that could result in a change in the primary beneficiary. Documentation of the key conclusions reached during the initial assessment could include those factors that may trigger a change in the primary beneficiary, helping facilitate the review in subsequent periods.

Figure 10-12

Reasons for a change in the primary beneficiary



Evaluation of the significant activities and when and how they may change is a key component of the ongoing evaluation of the primary beneficiary. See Example 10-9 for an illustration of evaluating a potential change in the primary beneficiary.

10.5 *Accounting for the consolidation or deconsolidation of a variable interest entity*

ASC 810 provides a framework for the initial consolidation or deconsolidation of a variable interest entity. In general, unless the VIE is under common control with the reporting entity, an initial consolidation of a VIE should be accounted for at fair value. The deconsolidation of a VIE also requires the determination of the fair value of any retained interest in the formerly consolidated entity. The overall accounting requirements are summarized in Figure 10-13.

Figure 10-13
Accounting for a variable interest entity

Type	Guidance	Outcome
Consolidation of a VIE under common control	<ul style="list-style-type: none"> □ Initial recognition based on historical cost. 	<ul style="list-style-type: none"> □ No gain or loss is recognized
Consolidation of a VIE that is a business	<ul style="list-style-type: none"> □ Evaluate based on definition of a business in the ASC Master Glossary and as described in ASC 805-10-55-4 through 55-9. □ Account for consolidation as a business combination following guidance in ASC 805. 	<ul style="list-style-type: none"> □ Goodwill may be recognized □ Gain may be recognized in a bargain purchase
Consolidation of a VIE that is not a business	<ul style="list-style-type: none"> □ Recognize and measure the assets (except for goodwill) and liabilities of the VIE in accordance with ASC 805-20-25 and 20-30. □ Assets or liabilities transferred to the VIE from the primary beneficiary are generally recorded at historical cost per ASC 810-10-30-3 and 30-4. 	<ul style="list-style-type: none"> □ No goodwill is recognized; gain or loss may result
Deconsolidation of a VIE	<ul style="list-style-type: none"> □ Account for deconsolidation in accordance with ASC 810. 	<ul style="list-style-type: none"> □ Gain or loss is recognized □ Retained interest is measured at fair value □ See the response to Question 10-13

See CG 2 for further information. In addition, see discussion of specific considerations for the accounting for the deconsolidation of a single power plant entity below.

10.5.1 Deconsolidation

ASC 810 requires deconsolidation of an entity when the consolidator loses its controlling financial interest:

Excerpt from ASC 810-10-40-4

A parent shall deconsolidate a subsidiary or derecognize a group of assets specified in the preceding paragraph as of the date the parent ceases to have a controlling financial interest in that subsidiary or group of assets.

As discussed in UP 10.4, a reporting entity should assess the primary beneficiary of a VIE on an ongoing basis. Due to the nature of the contractual and other arrangements associated with a typical single power plant entity, the primary beneficiary may change over time. As a result, a reporting entity may determine that it is no longer the primary beneficiary of a consolidated VIE, even in cases where it does not sell or otherwise dispose of its interest.

In accordance with ASC 810-10-40-5, deconsolidation of a VIE generally results in recognition of a gain or loss in the income statement. In addition, any retained equity interest or investment in the former subsidiary is measured at fair value as of the date of deconsolidation. If the reporting entity does not hold any equity interests in the VIE, there should be no gain or loss upon deconsolidation. For example, if a reporting entity initially consolidates a VIE as a result of a power purchase agreement and subsequently deconsolidates the VIE when the power purchase agreement expires, no gain or loss should be recognized. See BC 6.6 for further information on deconsolidation of a VIE.

Question 10-13

Should a reporting entity follow the consolidation guidance or the real estate guidance when accounting for the derecognition of a single power plant entity?

PwC response

It depends. A reporting entity may be required to deconsolidate a single power plant entity due to its sale, a loss of control, or changes in the structure that cause it to no longer be the primary beneficiary. ASC 810 provides guidance on the deconsolidation of a consolidated entity; ASC 360-20 provides guidance on the derecognition of real estate and in-substance real estate. The requirements for derecognition in ASC 360-20 are different than ASC 810 and may result in different accounting outcomes. In particular, ASC 360-20 prohibits immediate recognition of some or all of the potential gain on derecognition depending on any “continuing involvement” in the VIE; in some cases ASC 360-20 may also prohibit derecognition of the real estate altogether. As a result, in evaluating deconsolidation of an entity that primarily comprises real estate assets or is in-substance real estate, a determination needs to be made as to which guidance should be applied.

In-substance real estate is not defined in U.S. GAAP; therefore, judgment is necessary in determining when ASC 360-20 would apply. In general, a sale, transfer, or deconsolidation of a single power plant entity involves in-substance real estate if the plant involved is integral equipment (e.g., fossil fuel plants and most renewable energy facilities) and thus considered real estate. See UP 2.5.1.2 for further information on determining whether a power plant is integral equipment.

If the VIE holds significant real estate assets (including integral equipment), the reporting entity should further assess whether the sale, transfer, or deconsolidation involves in-substance real estate. Factors to consider in making this evaluation include:

- How important is the real estate to the activities of the business; is the real estate incidental or is the real estate the primary source of generation of income for the entity?
- What is the scope of the activities of the business? A single power plant entity that holds only a power plant would generally be viewed as in-substance real estate. However, an integrated utility with extensive operations beyond the real estate assets would likely be viewed differently.
- What is the relative value of the real estate as compared to the entity? Although there are no bright lines, the greater the percentage of the entity's total assets that comprise real estate, the greater the likelihood that the entity is in-substance real estate.

Generally, if a VIE is determined to be in-substance real estate, we believe the derecognition model in ASC 360-20 should be applied if the reporting entity determines that derecognition is appropriate under ASC 810. The determination of whether an entity is in-substance real estate requires judgment based on an analysis of the facts and circumstances of the nature of the entity, its activities, and its assets, liabilities, or contractual arrangements. Reporting entities should apply a consistent approach to evaluating whether an entity is in-substance real estate.

Note about recent standard setting

As of the date of this publication, ASC 606, *Revenue from Contracts with Customers*, has been issued and is effective for public business entities for annual reporting periods beginning after December 15, 2017, including interim periods within that reporting period, with early application permitted. ASC 606 introduces a new topic, ASC 610, *Other Income*, that provides considerations to determine whether there has been a transfer of control of an asset. Upon adoption, the guidance in ASC 610 should be utilized to determining the appropriate accounting for the derecognition of a non-financial asset, including in-substance real-estate.

Question 10-14

Does the conclusion that a VIE is in-substance real estate change if the VIE is a business?

PwC response

No. Real estate investment properties generally meet the definition of a business. Therefore, the fact that a VIE meets the definition of a business does not impact the determination of whether it is in-substance real estate.

10.6 Application examples

This section comprises a series of hypothetical scenarios to illustrate considerations in evaluating whether a contractual or other arrangement is a variable interest and in determining the primary beneficiary in evaluating single power plant entities. These

examples have been simplified, and different facts may significantly change the analysis. All of the examples assume that the entity is a VIE and the analysis is from the perspective of the developer. Similar considerations would apply to other variable interest holders. The analysis included in the examples does not apply to all scenarios, and a careful evaluation of all relevant facts and circumstances should always be performed for each specific fact pattern.

EXAMPLE 10-4

Tolling agreement that is not a lease

M&H Holding Company establishes a wholly owned subsidiary, Jacaranda Power Company (JPC), to design, construct, own, and operate a 500 MW combined-cycle natural gas-fired facility. M&H contributes land, air permits, and a turbine to JPC during the preconstruction phase. M&H also contributes \$100 million in equity, approximately 30% of the expected construction cost of \$325 million. M&H spends one year obtaining the remaining necessary permits, bargaining with an EPC contractor (EPC Company), identifying sources of construction financing, and negotiating a tolling agreement with the local utility. During the initial development stage, M&H holds the only interests in JPC and accounts for it as a consolidated subsidiary.

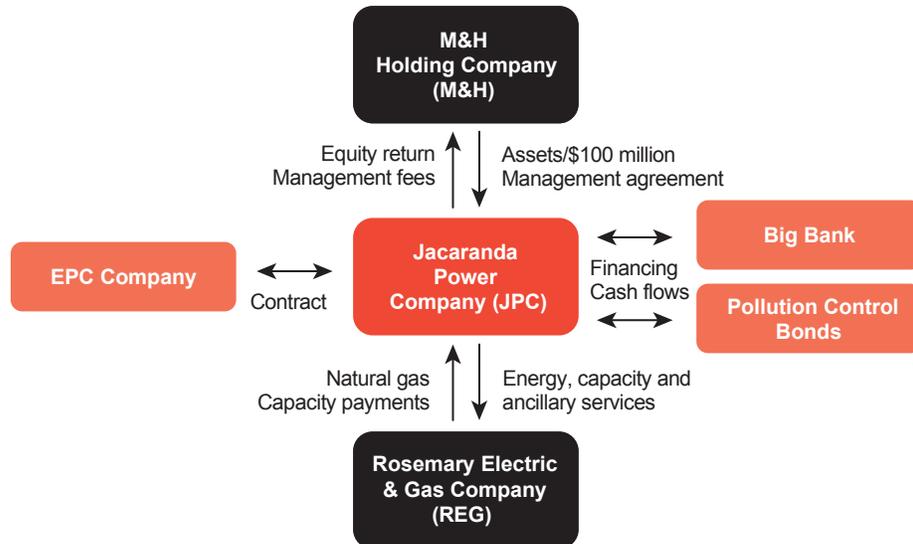
Construction and operations

On August 1, 20X1, the state regulator approves a proposed tolling agreement and JPC executes certain agreements:

- A 30-year tolling agreement with Rosemary Electric & Gas Company for all of the energy and capacity from the plant. Under the terms of the agreement, REG will supply natural gas to the facility and will receive electricity based on a 7.00 heat rate. The plant is expected to be operated as a base-load plant and REG will pay a fixed price for capacity, escalated annually by 2%. REG determines when to dispatch; there is no separate energy charge. The plant must have at least 90% availability; and REG has approval over operations and maintenance schedules. JPC must pay liquidated damages if the plant is not operational by a specified date. REG has certain step-in rights in the event of default. JPC determines that the contract does not meet the definition of a lease or a derivative and accounts for the agreement as an executory contract.
- Senior debt financing from Big Bank for \$175 million of the cost of plant construction. Under the terms of the debt agreement, the borrowings are repaid annually for the first 10 years after the commercial operation date. The senior debt financing agreement also includes certain protective rights (e.g., approval over the sale of the plant).
- JPC also issues pollution control bonds for the remaining cost of construction. The pollution control bonds will be paid after the senior debt is fully repaid and must be fully retired 20 years after COD.

JPC also enters into an agreement with EPC Company, an unrelated construction company, for construction of the plant. The plant will be built to JPC's specifications

and construction, will have a 35-year life, and will be managed by M&H under a management agreement. EPC Company is required to pay JPC liquidated damages if the plant does not achieve commercial operation by a specified date. In addition, M&H will be responsible for operations and maintenance of the facility. The following diagram summarizes JPC's key contractual agreements and other arrangements:



At the time of execution of the agreements, M&H performs an assessment and determines that JPC is exposed to the following risks:

- Construction risk associated with constructing the facility
- Operational risk associated with maintaining capacity as required by the contract (if capacity is not maintained, the debt and equity holders will not be fully repaid)
- Credit risk associated with possible default by the counterparty to the tolling agreement
- Commodity price risk associated with fuel and energy prices. During the contract period, the commodity price risk is absorbed by the tolling agreement. The plant is exposed to fuel and energy price risk beyond the initial contract period; however, given that the contract is for 30 years and the plant has a 35-year life, the risk beyond the initial contract is relatively minimal.

M&H evaluates the purpose and design of the entity as follows:

- The primary purpose for which the entity was created was to provide REG with use of the plant for 30 years, with substantially all of the benefits and obligations of ownership. JPC retains operational responsibility, and its ability to obtain the expected payments under the tolling agreement is dependent on its ability to operate the plant within the specified capacity and heat rate parameters. However, REG decides when to operate the plant and retains fuel cost exposure.

- The tolling agreement is designed to absorb energy price risk associated with the output during the contract period (30 years out of the expected 35-year useful life of the plant). This contract transfers a significant amount of the energy and capacity price risk to REG. The contract period will be sufficient to repay the debt holders and provide M&H with its expected return. M&H will retain exposure to expected fluctuations in the value of the property after year 30; however, any residual is considered upside by M&H.
- JPC was marketed to the lenders as an entity that is exposed to credit risk associated with the tolling agreement. The debt is senior to the tolling agreement. REG is a regulated utility with a strong credit rating. However, the transaction still involves credit risk, particularly due to the duration of the contract.
- JPC is exposed to construction risk with respect to completion of the generating facility in accordance with specified standards. M&H has a history of successfully completing similar projects and the EPC contractor has built numerous similar plants. Management does not anticipate significant variance from the budgeted overruns, based on historical experience and the nature of the plant.

What are the variable interests and the significant activities during each phase of the project?

Analysis

Based on the above analysis, M&H concludes that JPC was designed to create and pass along construction, operations, and credit risk to M&H and the lenders. It was also designed to create and pass along price risk related to the plant assets to REG through the tolling agreement. M&H also retains exposure to variability of cash flows in the period after expiration of the tolling agreement.

The potential variable interests are as follows:

Interest	Create or absorb risk?	Evaluation
M&H equity interests	Absorb	Variable interest—Equity is the junior interest and is paid last (ASC 810-10-55-23).
Senior debt	Absorb	Variable interest—Even senior debt is exposed to potential losses (ASC 810-10-55-24); however, the risk of significant loss is slight.
Pollution control bonds	Absorb	Variable interest—Subordinated debt is exposed to potential losses (ASC 810-10-55-24).
Tolling agreement	Absorb	Variable interest—The contract locks in future commodity price and protects JPC from commodity price risk (see further discussion of key evaluation factors in UP 10.2.2.2).

Interest	Create or absorb risk?	Evaluation
EPC contract	It depends	The agreement may meet the service contract scope exception. Judgment is required to determine if the liquidated damage provisions are customary in these types of arrangements (see UP 10.2.3.3).
Management contract, including operations and maintenance	Absorb	Variable interest—The contract payments are made to a decision maker, but the contract does not qualify for the service agreement exception because the decision maker holds other variable interests that would absorb more than an insignificant amount of the VIE’s expected residual returns (see UP 10.2.3.3).

All variable interest holders have the obligation to absorb losses of the entity or the right to receive benefits from the entity that could be significant. Therefore, as all variable interest holders would meet the second criterion of ASC 810-10-25-38A, further evaluation would be performed to determine which of the parties has the power to direct the activities of the VIE that most significantly impact its economic performance.

The most significant activities during the power plant life cycle are as follows:

Phase	Significant activities	Responsible party
Development	Initial strategy, siting, and other activities to prepare for construction Contracting, financing and regulatory approvals	M&H (no other variable interests during this stage)
Construction	Completion of construction	M&H (through equity and management contract) and EPC Company are both involved in significant decisions over construction. REG is entitled to liquidated damages in the event of default, but has no specific powers during this phase.
Operations—contracted period	Operations and maintenance Dispatch	M&H and REG each have responsibility for certain activities; see further evaluation below.
Post-contract	Same as initial contracted period	Depends on whether M&H enters into a new contract or operates the plant as a merchant facility

Construction phase

Once the financing is in place and the tolling agreement is executed, JPC signs the EPC contract. The EPC contractor will be managed by M&H through a management agreement; however, the contractor is responsible for construction of the plant in accordance with the specifications established by M&H and approved by REG. EPC Company will be required to pay liquidated damages to M&H if construction is not completed and commercial operation is not achieved by a specified date.

M&H determines that the initial strategy and contracting as well as control of operations, as further described below, are expected to have more significant impact than construction on JPC's economic performance over the life of the entity (which is expected to be the same as the life of the facility).

Who is the primary beneficiary of JPC during the construction phase?

Analysis

Although the EPC contract is important, there is not significant risk with construction because the contractor is experienced and the technology has been proven. As such, M&H would deem it highly likely that construction will be completed and that the plant will enter the operations phase. As a result, M&H would conclude that it is the primary beneficiary.

Operations — contracted period

During the contract period, M&H and REG will have responsibility for certain activities as follows:

- Operations and maintenance — M&H
- Dispatch — REG
- Fuel procurement — because of the structure of the contract (tolling agreement), the fuel procurement strategy does not have a direct impact on JPC's economic success. Fuel price risk is absorbed by the tolling agreement with REG.

Who is the primary beneficiary of JPC during the contract period?

Analysis

M&H had responsibility for the initial development of the project, contracting, and strategy. The significant activities during the operational phase are operations and maintenance, and dispatch. The determination of which of these activities is more significant depends on the terms of the tolling agreement. Because all cash flows to JPC are obtained through the capacity payment, M&H would likely conclude that operations and maintenance (leading to availability) is the most important activity. In contrast, if the contract terms resulted in substantially all of the cash flows being obtained through start-up charges and the energy payment, dispatch may be more

important. In this case, because operations and maintenance was determined to be the most significant activity, M&H would be considered the primary beneficiary.

Post-contract

At the time the tolling contract ends, M&H would need to reassess significant activities and control based on any contractual agreements put in place after the initial contract period.

Debt holder considerations

Throughout the life cycle of the power plant, the debt holders do not have the power to direct activities that most significantly impact JPC's economic performance; therefore, they are likely not the primary beneficiary at any stage. The rights held by the debt holders have the characteristics of protective rights, rather than providing any substantive controlling financial interest. The debt holders would need to include appropriate disclosure of their interests in their separate financial statements.

EXAMPLE 10-5

Tolling agreement that is a lease

Assume the same facts as in Example 10-4; however, the fixed pricing in the tolling agreement escalates annually by changes in the Consumer Price Index. M&H Holding Company concludes that the contract is an operating lease. M&H assesses the design of the entity and the related risks. It concludes that the only difference from the evaluation performed in Example 10-4 is that risk associated with the inputs and outputs of the facility has been designed out of the entity during the contract period because of the lease arrangement with Rosemary Electric & Gas Company.

Who is the primary beneficiary of JPC?

Analysis

The tolling agreement is not a variable interest because it is an operating lease. However, the lease includes an embedded operations and maintenance agreement (generally represented by a portion of the energy payments). The operations and maintenance agreement absorbs risk from the entity by reducing the variability of JPC's cash flows compared to operation as a merchant facility, which would not have an operations and maintenance contract. Although there is some uncertainty because payments will not be made unless the plant dispatches, the facts indicate that the plant is expected to be operated as a base-load plant, with a 90% capacity factor. Therefore, M&H would likely conclude that REG holds a variable interest in JPC via the operations and maintenance agreement embedded in the lease.

In evaluating the most significant activities, the key change as a result of the conclusion that the contract is a lease is that fuel procurement and dispatch are generally outside the scope of the VIE's activities. The lease is for the use of the power plant itself. Thus, the production inputs and the output from the plant are associated with the lease contract itself and are outside the design of the entity. In this fact

pattern, the plant is base load and expected to dispatch whenever available. Therefore, in assessing the most significant activities, operations have the most significant impact on the VIE's economic performance. M&H would therefore be the primary beneficiary of the VIE because it controls operations.

In this example, REG does not make any separate payments for dispatching the plant. However, if the lease payments included a component based on dispatch, JPC would retain the risk of variability in payments related to these contingent rents. In such cases, M&H would need to assess the relative importance of operations as compared to dispatch in determining which activities are most significant.

EXAMPLE 10-6

Fixed-price power purchase agreement that is not a lease

Assume the same facts as in Example 10-4; however, the agreement is a fixed-price power purchase agreement. JPC is responsible for procuring its own fuel and will sell capacity and energy to Rosemary Electric & Gas Company (REG) at fixed prices as established in the contract, escalated annually by CPI. REG is required to take all power produced by the entity and has no dispatch rights. At the time the energy sales agreement is signed, JPC signs natural gas supply agreements for the first five years of operations. M&H Holding Company, JPC's equity holder, identifies an additional risk—fuel-supply risk created by the fixed-price power purchase agreement. The purpose and design of the entity are considered as follows:

- The primary purpose for which the entity was created was to provide REG with an assured source of supply at a fixed price and to provide the equity holders with a return. M&H, the owner of JPC, retains operational responsibility and substantially all of the risks of ownership, including fuel-supply risk. JPC's ability to obtain the expected payments under the power purchase agreement is dependent on its ability to operate the power plant within the specified capacity parameters.
- The offtake agreement provides JPC with an expected payment stream for 30 years of the expected 35-year useful life of the plant. The contract period is expected to be sufficient to repay the debt holders and provide M&H with its expected return. However, its ability to make these payments is highly dependent on its ability to obtain fuel at prices low enough to make a profit. JPC also will retain exposure to expected fluctuations in value of the property after year 30.
- JPC was marketed to the lenders as an entity that is exposed to credit risk associated with the power purchase agreement with REG. REG is a regulated utility with a strong credit rating. However, the transaction still involves credit risk, particularly due to the duration of the contract.
- There is no change in construction risk compared to Example 10-4.

Who is the primary beneficiary of JPC?

Analysis

In evaluating the potential variable interests, the power purchase agreement is a *creator* of risk due to the fuel-supply risk that it has introduced into the entity structure. The same conclusions as in Example 10-4 regarding the other variable interests apply to this example.

As M&H controls fuel, dispatch, and operations and maintenance, it is the primary beneficiary.

EXAMPLE 10-7

Outsourced operations and maintenance

Assume the same facts as in Example 10-4 above; however, M&H Holding Company contracts with a third party to provide operations and maintenance services to Jacaranda Power Company (JPC). M&H can replace the operations and maintenance service provider for any reason with one-year notice. It can also replace the operations and maintenance provider for cause at any time. The services will be provided as specified in the contract, with general oversight by M&H. M&H analyzes the contract in accordance with the guidance in ASC 810-10-55-37, and determines that the operations and maintenance agreement is not a variable interest because it meets all of the criteria for the service provider exception.

Who is the primary beneficiary of JPC?

Analysis

The operations and maintenance provider is working at M&H's direction under standards established by M&H, and M&H can, at its own discretion (subject to the terms of the contract), replace the operations and maintenance provider. As a result, M&H still has the power to direct the operations and maintenance activities. As such, there would be no change to the conclusion reached in Example 10-4 and M&H would be the primary beneficiary.

Note that additional evaluation should be performed if the operations and maintenance agreement was for a longer duration and did not provide for oversight by M&H or the ability of M&H to replace the third party.

EXAMPLE 10-8

Tolling agreement with a call option

Assume the same fact pattern as Example 10-5 (tolling agreement is a lease); however, Rosemary Electric & Gas Company (REG) has the contractual right to call the plant for a fixed price at the end of the contract period. The pricing of the call option is such that REG would be expected to exercise the option at the end of the tolling period. M&H Holding Company concludes that this call option is a variable interest in accordance with ASC 810-10-55-39.

Who is the primary beneficiary of JPC?

Analysis

The determination of the primary beneficiary should be based on the existing rights and powers held by the various parties to the VIE and the impact of those powers on the entity's economic performance during its life. If the same or substantially the same powers are held by different parties at different times in the entity's life, those powers should be attributed to the entity holding them at the reporting date. During the initial phase, M&H had control of strategy and contracting; however, it agreed to cede this power to REG at the end of the contract term pursuant to the power purchase agreement. M&H also retains operational control of the power plant during the initial contract period.

The call option would not change the determination that M&H is the primary beneficiary during the contract period as determined in Example 10-5 because the powers provided by the call are substantially consistent with the powers held by JPC during the initial contract period. Because the powers are similar in nature, they are considered only by the party that holds them as of the reporting date. The expectation of control in the future is not part of the current primary beneficiary analysis. REG's ability to exercise power over the activities is contingent upon exercise of the call option and would not become effective until that occurs. However, given the significance of the call option, M&H should disclose this variable interest and the potential for the future call in the notes to its financial statements.

EXAMPLE 10-9

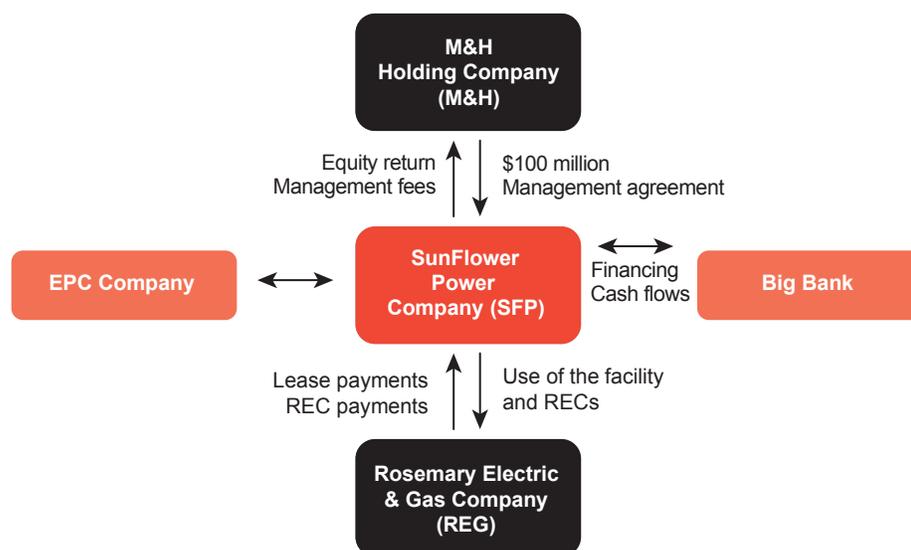
Renewable energy project

M&H Holding Company (M&H) decides to expand into renewable resources and establishes a wholly owned subsidiary, SunFlower Power Company (SFP), with the intention of building a 100 MW solar facility. M&H intends to finance the solar plant with a combination of additional equity and debt. M&H spends six months conducting solar studies, obtaining land leases, ordering solar panels, and performing other activities in preparation for construction. M&H provides \$100 million in initial equity financing. On March 12, 20X2, SFP executes the following agreements:

- A 20-year agreement with Rosemary Electric & Gas Company (REG) for the sale of all energy and renewable energy credits from the solar facility. The contract price is based on a fixed price for energy, escalated annually based on a CPI, plus \$25 per renewable energy credit. The price for renewable energy credits will also increase annually in accordance with changes in the CPI. SFP guarantees a minimum availability of the plant of 30% and REG is required to take all energy and RECs produced. REG has certain step-in rights in the event of default during the construction and operations phases and has approval rights over the timing of operations and maintenance activities. M&H determines the contract is an operating lease.
- Senior debt financing from Big Bank for the remaining \$350 million of the cost of construction. The debt is repaid annually for the first 10 years after the commercial operation date and includes certain protective rights (e.g., approval over the sale of the power plant).

M&H has previously adopted an accounting policy that RECs are not output (see UP 7 for more information about accounting for RECs). It separately evaluates the REC sale as part of a multiple-element arrangement and accounts for the forward sale of RECs as an executory contract.

SFP also enters into an agreement with EPC Company, an unrelated construction company, for construction of the plant. The plant will be built to SFP's specifications and construction will be managed by M&H under a management agreement. In addition, M&H will be responsible for operations and maintenance of the facility. The following diagram summarizes SFP's key contractual agreements and other arrangements:



This example does not further discuss the construction phase because the considerations are similar to those discussed in Example 10-4. M&H determines that SFP is exposed to the following risks:

- Construction risk associated with constructing the facility
- Operational risk associated with the level of production from the plant (if there is not sufficient production, the debt holder and M&H will not be fully repaid)
- Credit risk associated with possible default by REG
- Energy and REC price risk beyond the contract period; the 20-year contract period is expected to be sufficient to fully repay the debt and equity holders, including a return.

M&H evaluates the purpose and design of SFP as follows:

- The primary purpose for which the entity was created was to provide REG with the use of the facility and the RECs for a 20-year period (the regulated utility needs the credits to meet the state renewable-portfolio standards). As a result of the production guarantee, SFP takes on additional operational risk that there will

be sufficient sunlight to meet the minimum availability requirements. In addition, SFP retains operational responsibility and its ability to obtain the expected payments under the power purchase agreement is dependent on the initial siting of the plant, weather and solar conditions.

- The 20-year offtake agreement provides REG with benefit over that period. The contract period is expected to be sufficient to repay the debt holders and to provide M&H with its expected return. M&H retains exposure to expected fluctuations in the value of the property after year 20; however, it considers any residual as potential upside.
- SFP was marketed to the lenders as an entity that is exposed to credit risk associated with the power purchase agreement and production risk associated with initial siting of the plant (see further discussion below) and production levels that are dependent on weather. REG is a regulated utility with a strong credit rating; however, the transaction still involves credit risk, particularly due to the duration of the contract.
- The entity is exposed to construction risk with respect to completion of the solar facility in accordance with specified standards. M&H performed solar studies and obtained other support for the expected level of production; however, this is its first venture into renewable power plants.

Based on the above analysis, SFP was designed to create and pass along construction, operational, and credit risk to M&H and the lenders. In addition, REG may have risk associated with the RECs because they are dependent on production.

Who is the primary beneficiary?

Analysis

The potential variable interests are as follows:

Interest	Absorb or create risk?	Evaluation
M&H equity interests	Absorb	Variable interest — equity is the junior interest and will be paid last (ASC 810-10-55-23).
Senior debt	Absorb	Variable interest — even senior debt is exposed to potential losses (ASC 810-10-55-24).
Power purchase agreement	Not applicable	Not applicable — the power purchase agreement is an operating lease and qualifies for the operating lease exception in ASC 810-10-55-39. However, M&H concludes that the power purchase agreement also includes an operations agreement (see management contract below).

Interest	Absorb or create risk?	Evaluation
REC sale included in the power purchase agreement	Absorb	Variable interest — the REC sale absorbs price risk from the entity. M&H considers whether the minimum production guarantee creates risk; however, it has studies that indicate an expected capacity factor of 65%, well in excess of the 30% minimum. Therefore, this risk is deemed minimal and does not impact the conclusion that the REC sale is a variable interest.
EPC contract	It depends	Variable interest — the EPC contract may qualify for the service contract exception (see UP 10.2.3.3).
Management contract, including operations and maintenance	Absorb	Variable interest — the payments are made to the decision maker, but the contract does not qualify for the service agreement exception because the decision maker holds other variable interests that would absorb more than an insignificant amount of the VIE's expected residual returns (see UP 10.2.3.3).

All variable interest holders have the obligation to absorb losses of the entity or the right to receive benefits from the entity that could be significant. Therefore, further evaluation is necessary to determine which of the parties has the power to direct the activities of the VIE that most significantly impact its economic performance.

Both Big Bank and REG hold protective rights in the entity. However, M&H is the only entity with any power to direct the activities. Although REG has approval rights over the schedule of operations and maintenance activities, M&H has overall responsibility. Therefore, M&H would be considered the primary beneficiary.

EXAMPLE 10-10

Renewable energy project — renewable energy credits are output

Assume the same facts as in Example 10-9; however, M&H Holding Company's accounting policy is that RECs are part of the output of the facility (see UP 7 for further information about accounting for RECs).

Who is the primary beneficiary?

Analysis

Because the RECs are output, the RECs are part of the operating lease and do not represent a separate variable interest (the REC output is obtained from use of the facility). However, the REC accounting policy does not change any of the powers held by the parties. Therefore, M&H would still be the primary beneficiary, consistent with the analysis in Example 10-9.

EXAMPLE 10-11**Renewable energy project – certain shared powers**

Assume the same facts as in Example 10-9; however, M&H Holding Company obtains a portion of the financing for SunFlower Power Company (SFP) from a tax equity investor, Desert Sun Tax (DST), a wholly-owned subsidiary of a U.S.-based C-Corporation. Under the terms of the agreement, DST will provide \$65 million in initial financing in exchange for all of the production tax credits and priority in distribution. DST will receive 90% of the distributions until its equity contribution is fully repaid or a specified investment return has been achieved, at which time its share will be reduced to 10%. DST participates on the management committee with M&H and all major decisions (e.g., sources of additional financing, budgets, project expansion) require agreement from both parties. M&H will be responsible for all day-to-day operations under a management agreement. DST can unilaterally replace M&H in the event of default; otherwise, a change in operator requires agreement from both parties.

Who is the primary beneficiary?

Analysis

DST's investment is a variable interest because it has exposure to losses and will absorb a portion of the risk from the entity. M&H would also need to consider whether DST's participation in the management committee and shared involvement in major decisions would impact the determination of the primary beneficiary. Key considerations in this evaluation include:

- M&H was responsible for the initial design of the entity and conducted certain pre-development activities before DST became involved. As further discussed in UP 10.4.1.6, involvement in initial design is a factor in the determination of the primary beneficiary. M&H is the operator and has day-to-day power over operations. Absent a default, M&H cannot be replaced without its consent.
- The activities that will most significantly impact the success of the entity were substantially determined during the development stage, including determining the sources (and cost) of financing, siting the facility, negotiating the power purchase agreement, and obtaining all necessary permits. These activities were conducted by M&H.
- After initial development, the activity with the most influence over performance is operation of the facility. M&H holds this power through its management agreement and, as noted, cannot be replaced unless it agrees to such replacement, absent default.
- Because of the nature and purpose of the entity, the decision-making powers held by the management committee (approval of budgets, expansion of the project, new contracts) are not expected to have a significant impact on SFP's economic performance. However, any significant changes in strategy could have a material impact on SFP's economic performance.

Based on the factors outlined above, there is a bias that M&H retains the power over the significant activities of SFP. It established the initial design, is responsible for managing operations, and would share power over any other decisions significantly impacting the economic performance of the plant. Although certain powers are shared such that no one party has the power to direct those activities, M&H alone holds additional powers with the ability to impact SFP's economic performance. Based on these factors, M&H would be the primary beneficiary.

EXAMPLE 10-12

Renewable energy project — energy and renewable energy credits sold to separate off-takers

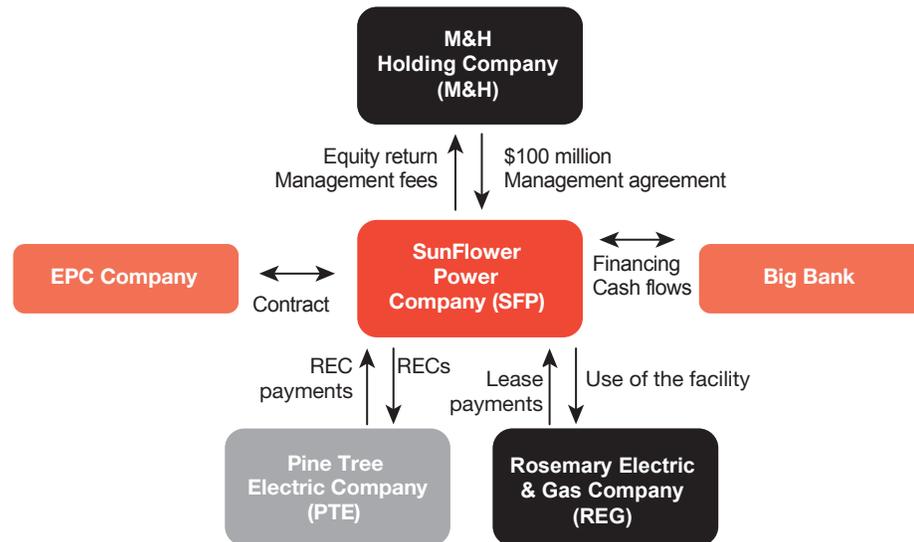
Assume the same facts as in Example 10-9; however, two years after the project commences operations, Rosemary Electric & Gas Company (REG) determines that it no longer needs the RECs. SunFlower Power Company (SFP) and REG agree to a termination payment that is approved by Big Bank on the condition that SFP sign a replacement agreement for equal or greater value. REG will continue to buy the energy at the scheduled price in the contract. SFP negotiates an agreement with Pine Tree Electric Company (PTE) to purchase the renewable energy credits for \$30 each, increasing annually by the CPI.

Who is the primary beneficiary?

Analysis

As a result of this change, the primary beneficiary should be reassessed. The PTE contract was signed after the power plant was already in operation, which suggests that it may not have been contemplated in the design. However, the financing agreements required approval of any change to the contracting parties and would not permit termination of the original REC sale without a replacement. Furthermore, the REC sale absorbs risk from the entity. Therefore, PTE holds a variable interest. In addition, because M&H has an accounting policy that RECs are not output, there is no change to its conclusion that the arrangement with REG is a lease. There is no change to the evaluation of any of the other variable interests.

The following diagram summarizes SFP’s key contractual agreements and other arrangements:



Based on the above, there is no change to the primary beneficiary conclusion reached in Example 10-9 and M&H is still the primary beneficiary. Although the variable interest holders have changed, M&H is still the primary beneficiary because it is the only entity with the power to direct SFP’s significant activities.

EXAMPLE 10-13

Renewable energy project – prepaid power agreement

Assume the same facts as in Example 10-9; however, M&H Holding Company cannot identify an economic source of debt financing. Therefore, in lieu of the senior debt from Big Bank, M&H negotiates with Rosemary Electric & Gas Company (REG) to prepay a substantial portion of the power purchase agreement. In exchange, REG will receive a discount on the energy and REC purchases over the life of the agreement.

Who is the primary beneficiary?

Analysis

The change in financing does not change the conclusion that the contract is still a lease; however, the contract now also includes an additional embedded element, the initial payment. The initial payment represents a source of financing and is effectively a debt instrument. Therefore, the prepaid amount is a variable interest. However, as the powers to direct the significant activities of the entity have not changed, M&H would still be determined to be the primary beneficiary.

Chapter 11: ***Inventory***

11.1 Chapter overview

Inventory held by utilities and power companies typically includes:

- Fuel (e.g., natural gas, coal, fuel oil) used in the production of electricity
- Natural gas or other commodities held for sale to retail or other customers
- Emission allowances and renewable energy credits (referred to collectively herein as environmental assets)
- Materials and supplies

This chapter addresses certain industry issues for fuel and environmental asset inventory held by utilities and power companies, including specific considerations related to impairment. It also addresses the accounting for materials and supplies.

See ARM 3800 and 3805 for information on accounting for inventory in general.

11.2 Lower of cost or market

The primary measurement basis for inventories is cost, provided cost is not higher than the net amount realizable from the subsequent sale of the inventories. The type of inventory typically held by utilities and power companies, including fuel and environmental assets, may be particularly susceptible to potential lower of cost or market write-downs due to the volatility in related prices. Reporting entities should assess the carrying value of inventory on a periodic basis. They may need to make adjustments to the recorded balances triggered by recent events, including changes in spot and forward prices, changes in legislative and regulatory requirements, and other economic or technological factors, such as changes in the planned resource mix or new technology that affects asset usage.

11.2.1 Lower of cost or market adjustments

ASC 330 establishes LOCOM as the guiding principle to apply in assessing whether cost or a lower estimate of net realizable value should be used in valuing inventories. ASC 330-10-20 defines “market” as current replacement cost provided that it meets two specified conditions.

Definition from ASC 330-10-20

Market: As used in the phrase lower of cost or market, the term market means current replacement cost (by purchase or by reproduction, as the case may be) provided that it meets both of the following conditions:

- a. Market shall not exceed the net realizable value
- b. Market shall not be less than net realizable value reduced by an allowance for an approximately normal profit margin.

Net realizable value is equal to estimated selling price less reasonably predicible costs to sell. For liquid assets (such as natural gas) held for sale, the current spot market price usually equals net realizable value, unless the assets require transportation to the liquid selling point (in which case transportation costs would need to be incorporated). Determination of the market price for less liquid assets or assets held for use may be more difficult and application of the guidance requires judgment.

Excerpt from ASC 330-10-35-4

In applying the rule, however, judgment must always be exercised and no loss shall be recognized unless the evidence indicates clearly that a loss has been sustained.

Figure 11-1 summarizes key factors to consider in assessing an LOCOM measurement.

Figure 11-1
Inventory LOCOM considerations

	Inventory held for use	Inventory held for sale
Basis of evaluation	<ul style="list-style-type: none"> □ Based on forward prices (e.g., power prices) at the time of planned generation 	<ul style="list-style-type: none"> □ Based on spot prices with consideration of forward prices
Key questions	<ul style="list-style-type: none"> □ Is anticipated cost of generation (including the cost of the related inventory) below future anticipated power prices? 	<ul style="list-style-type: none"> □ If there is a decline in spot prices; is it seasonal or temporary?
Other	<ul style="list-style-type: none"> □ Inventory held in excess of projected operating or compliance needs should potentially be evaluated as held for sale □ Planned timing of use may impact the evaluation □ Regulated utilities may consider sales to regulated retail customers; others should base evaluation on market (merchant) prices and firm sales commitments 	<ul style="list-style-type: none"> □ A write-down may not be necessary if price declines are seasonal or temporary □ Firm sales commitments above carrying value may indicate no LOCOM adjustment is necessary □ Regulated utilities selling natural gas with a cost recovery mechanism can consider the mechanism in determining whether an LOCOM adjustment is needed (see the response to Question 11-4)

In performing an LOCOM assessment, the reporting entity should consider the intended use of the inventory (whether held for sale or held for use) as it may impact the assessment. Market price volatility and the seasonality of the inventory may also impact the assessment. In particular, the evaluation of fuel or environmental assets

held for sale may be complex because of the need to consider future sales commitments and seasonal price fluctuations.

The following questions address common application matters related to the Locom principle and inventory impairments.

Question 11-1

How should spot and forward prices be considered in performing a Locom assessment?

PwC response

Reporting entities should record Locom adjustments in the period the loss is sustained; therefore, spot price declines as of the balance sheet date may indicate the need for a Locom adjustment. In addition, reporting entities should consider changes in spot prices subsequent to the balance sheet date in evaluating whether an Locom adjustment is necessary. Specific considerations include:

- Increases in prices after the reporting date may indicate that a previously observed price decline is temporary
- If forward prices indicate a price recovery, it may be appropriate to maintain inventory at carrying value
- Continued price declines after the reporting date may confirm the existence of underlying issues at that date in the valuation of the inventory

The trend in both spot and forward prices at the balance sheet date will provide information that can be used to determine whether a Locom adjustment is necessary. If a price recovery above the current carrying value is not expected before the inventory is expected to be sold, the inventory should be written down to net realizable value in the current period, absent firm sales commitments at prices above the current carrying value. Once the carrying value has been written down, a subsequent write-up of the carrying value is precluded, except as discussed in UP 11.2.2.

Question 11-2

How does a lower of cost or market adjustment to inventory affect earnings if the inventory is the hedged item in a cash flow hedge?

PwC response

It depends. Reporting entities may designate the forecasted purchase or sale of inventory (e.g., natural gas) as the hedged item in a cash flow hedge. If the hedge is effective, any gains or losses on the hedging derivative are deferred in accumulated other comprehensive income until the forecasted purchase or sale affects earnings. Reporting entities are required to perform Locom adjustments on inventory in accordance with ASC 330, even if hedge accounting is applied. However, ASC 815-30-35-43 provides specific guidance regarding the treatment of deferred hedging gains

and losses related to a hedged asset or liability for which an impairment loss is recorded.

ASC 815-30-35-43

If, under existing requirements in GAAP, an impairment loss is recognized on an asset or an additional obligation is recognized on a liability to which a hedged forecasted transaction relates, any offsetting net gain related to that transaction in accumulated other comprehensive income shall be reclassified immediately into earnings. Similarly, if a recovery is recognized on the asset or liability to which the forecasted transaction relates, any offsetting net loss that has been accumulated in other comprehensive income shall be reclassified immediately into earnings.

Therefore, if a reporting entity records an LOCOM adjustment of inventory that has been designated as the hedged item in a cash flow hedge, it would also concurrently reclassify to earnings an equivalent amount of any gains deferred in accumulated other comprehensive income related to the hedge. As a result, there may be circumstances when a reporting entity can mitigate or eliminate the effect of an LOCOM adjustment. See DH 9.2 for further information on evaluating impairments in conjunction with hedge accounting.

New guidance

In July 2015, the FASB issued ASU 2015-11, *Simplifying the Measurement of Inventory*, which simplifies the LOCOM analysis discussed above. This ASU is effective in fiscal years beginning after December 15, 2016, and may impact the evaluation of inventory impairment.

11.2.2 *Interim period considerations*

ASC 270 provides some flexibility in accounting for inventory price declines in interim periods. This is particularly useful in considering LOCOM adjustments related to fuel inventory and environmental assets classified as inventory, because of their potential for significant price volatility. ASC 270-10-45-6(c) provides guidance in addressing interim fluctuations in inventory prices.

ASC 270-10-45-6(c)

Inventory losses from market declines shall not be deferred beyond the interim period in which the decline occurs. Recoveries of such losses on the same inventory in later interim periods of the same fiscal year through market price recoveries shall be recognized as gains in the later interim period. Such gains shall not exceed previously recognized losses. Some market declines at interim dates, however, can reasonably be expected to be restored in the fiscal year. Such temporary market declines need not be recognized at the interim date since no loss is expected to be incurred in the fiscal year.

ASC 330-10-55-2 references this guidance, indicating that write-downs are generally required unless the decline is due to seasonal price fluctuations.

Consistent with this guidance, reporting entities can consider forward prices when evaluating price declines in an interim period. If forward prices indicate that the decline is seasonal with recovery expected, and the reporting entity has the ability and intent to hold the inventory until prices recover, it may not be necessary to record a write-down in an interim period.

Furthermore, as noted in ASC 270-10-45-6(c), if a write-down is recorded and prices subsequently recover, a reporting entity may only restore amounts previously written-off if the price recovery occurs in the same year.

11.3 Firm purchase commitments for inventory

Reporting entities may enter into firm purchase commitments for their fuel or other inventory. ASC 330 provides guidance regarding potential losses that a reporting entity may sustain as a result of firm purchase commitments for inventory.

ASC 330-10-35-17

A net loss on firm purchase commitments for goods for inventory, measured in the same way as are inventory losses, shall be recognized in the accounts. The recognition in a current period of losses arising from the decline in the utility of cost expenditures is equally applicable to similar losses which are expected to arise from firm, uncancelable, and unhedged commitments for the future purchase of inventory items.

In some cases, forward purchase contracts for fuel, or emission allowances to be classified as inventory, are accounted for as derivatives and measured at fair value. The reporting entity should record any reduction in the fair value associated with those contracts through a fair value adjustment. However, if such forward inventory purchase commitments are accounted for as executory contracts, the reporting entity should evaluate whether future sales related to the inventory commitments will be sufficient to cover any potential losses. In accordance with ASC 330-10-35-18, if a reporting entity has firm sales contracts or other circumstances that indicate it will be protected from an adverse purchase commitment, it should not record a loss.

ASC 330-10-35-18

The utility of such commitments is not impaired, and hence there is no loss, when the amounts to be realized from the disposition of the future inventory items are adequately protected by firm sales contracts or when there are other circumstances that reasonably assure continuing sales without price decline.

For example, if the reporting entity has firm commitments for the sale of power at a price in excess of its fuel cost, such that no loss will be sustained related to the purchase of the fuel, then no impairment should be recognized. However, if a reporting

entity cannot demonstrate protection as indicated in ASC 330-10-35-18, it should record a reserve for anticipated losses.

Question 11-3

Are reporting entities required to record losses associated with adverse purchase commitments for items not accounted for as inventory?

PwC response

No. A reporting entity may have firm purchase commitments for items that are not considered inventory, such as renewable energy credits or emission allowances accounted for under an intangible asset model. The guidance in ASC 330-10-35-17 and 35-18 only applies to firm purchase commitments for inventory.

11.4 ***Accounting for inventory at fair value***

Some reporting entities may hold inventory such as natural gas, coal, and environmental assets for the purpose of executing trading strategies. Because of the fungible nature of commodities and depending on reporting objectives, some may question whether it is appropriate to report these items held in inventory at fair value. ASC 330 provides guidance on this question.

ASC 330-10-35-15

Only in exceptional cases may inventories properly be stated above cost. For example, precious metals having a fixed monetary value with no substantial cost of marketing may be stated at such monetary value; any other exceptions must be justifiable by inability to determine appropriate approximate costs, immediate marketability at quoted market price, and the characteristic of unit interchangeability.

ASC 330-10-35-16

It is generally recognized that income only accrues at the time of sale and that gains may not be anticipated by reflecting assets at their current sales prices. However, exceptions for reflecting assets at selling prices are permissible for both of the following:

- a. Inventories of gold and silver, when there is an effective government controlled market at a fixed monetary value
- b. Inventories representing agricultural, mineral, and other products, with all of the following criteria:
 1. Units of which are interchangeable
 2. Units of which have an immediate marketability at quoted prices
 3. Units for which appropriate costs may be difficult to obtain.

Consistent with this guidance, recording inventory above cost would only be appropriate in exceptional cases. Furthermore, the SEC staff has stated that it will object to the use of mark-to-market accounting for inventories except in extremely rare cases, when all of the criteria in ASC 330-10-35-15 and 35-16 are met. We would not expect inventory held by utilities and power companies to meet the criteria as fuel and environmental assets do not meet the “exceptional” criterion. Reporting entities would be expected to be able to determine appropriate approximate costs. Therefore, such items should not be reported at fair value.

In addition, ASC 932 provides accounting guidance for oil and gas companies and specifically prohibits measuring physical inventory at fair value, except when indicated by guidance in the authoritative literature (ASC 932-330-35-1). Reporting entities may report commodity inventories above cost only when they operate in an industry that specifically permits it. For example, if a reporting entity is a broker dealer and within the scope of ASC 940, *Financial Services—Broker and Dealers* (ASC 940), certain of its commodity inventories may be reported at fair value. However, the reporting entity should be specifically within the scope of ASC 940 and other reporting entities cannot analogize to the guidance if outside its scope.

11.5 *Materials and supplies*

Materials and supplies generally consist of high volumes of low value parts that are held for the purpose of replacing parts within or performing repairs of utility plant. Often, materials and supplies are held for long periods of time and for the purpose of maintaining sufficient quantities of essential parts that may not be easily or quickly replaced from the market.

Industry practice is to account for materials and supplies following the guidance in ASC 330.

Partial definition from ASC 330-10-20

Inventory: . . . By trade practice, operating materials and supplies of certain types of entities such as oil producers are usually treated as inventory.

In accounting for materials and supplies, reporting entities should apply a consistent costing method and follow the guidance for LOCOM in ASC 330. Adjustments to reflect LOCOM of materials and supplies may arise due to changes in price levels or due to obsolescence.

Excerpt from ASC 330-10-35-2

Thus, in accounting for inventories, a loss shall be recognized whenever the utility of goods is impaired by damage, deterioration, obsolescence, changes in price levels, or other causes. The measurement of such losses shall be accomplished by applying the rule of pricing inventories at the lower of cost or market.

Consistent with this guidance, reporting entities should perform LOCOM assessments based on changes in factors that impact the market price of parts, in addition to considering obsolescence. Because materials and supplies may be used as replacement parts of utility plant over a long period of time, reporting entities should regularly evaluate slow moving parts to determine whether a write-down or reserve for obsolescence is necessary. The analysis should consider:

- The nature of the part
- The length of time it has been in inventory
- Typical turnover
- Technological advances (if any)
- Any market information about the part

Certain materials and supplies may be accounted for as “capital spares” and classified as part of property, plant, and equipment. These parts should be capitalized or expensed when used and are generally evaluated for impairment in accordance with the guidance in ASC 360. See UP 12.2.4 for further information on capital spares.

11.6 *Regulated utilities*

ASC 330-10-15-3 states that the guidance in ASC 330 may not necessarily apply to regulated utilities, however, it does not provide any specific exceptions and we generally do not expect there to be a difference in how regulated utilities apply the guidance. However, regulated utilities may be provided specific recovery mechanisms from regulators for inventory-related costs, such as fuel. In such cases, the regulated utility would consider this mechanism when evaluating the impact of potential impairments or reserves. See UP 17 for information regarding the recognition of regulatory assets and liabilities.

Question 11-4

How should a regulated utility with a direct pass-through mechanism for fuel or purchased natural gas costs account for an LOCOM adjustment?

PwC response

Inventory should be recorded based on LOCOM (see UP 11.2). ASC 330-10-20 states that “market” should not be less than net realizable value reduced by an allowance for an approximately normal profit margin. If a regulated utility has a direct pass-through mechanism for fuel or purchased natural gas costs, then it is permitted to recover from its customers an amount equivalent to the original cost of the inventory (the regulated utility’s normal profit margin on the cost is zero). Therefore, a reporting entity in this situation would not be required to record an LOCOM adjustment for fuel or purchased natural gas, even if the spot market price has declined below cost.

Chapter 12: ***Plant***

12.1 Chapter overview

Large-scale construction projects undertaken by utilities and power companies often result in accounting matters pertaining to capitalization of costs, operations and maintenance, depreciation, and asset retirement obligations. As a result, accounting for capital assets is often a focal point for reporting entities in the industry. This chapter discusses industry-specific topics related to accounting for plant assets, including:

- Capital projects (capital versus expense)
- Depreciation
- Maintenance, including major maintenance
- Impairment

See UP 13 for information on accounting for asset retirement obligations related to power plants and other utility assets as well as UP 14 for discussion of nuclear power plant issues. See also UP 18 for information on plant-accounting considerations specific to regulated utilities.

12.2 Accounting for capital projects

Identifying capital projects and determining which costs should be capitalized is a key focus in the accounting for construction projects and plant additions. Capital costs may include labor, materials and supplies (including stores expense), transportation, engineering services, certain overheads, insurance, employee benefits, compensation for injuries and damages, taxes, and capitalized interest. Similarly, an expenditure that adds to the productive capacity or improves the efficiency of an existing facility can be considered a capital item. Costs that are not necessary in readying an asset for use should be treated as an expense in the period in which they occur.

This section primarily focuses on capitalization policies for power companies and other projects for which construction is not subject to regulation, including special considerations for projects constructed for sale or rental (lease). It also specifically addresses the determination of components, accounting for capital spares, and the determination of a facility's commercial operation date. The capitalization policies for regulated utilities may differ from the guidance discussed in this section, due to the regulatory process. See UP 18.2 for further information.

12.2.1 Initial measurement

ASC 360-10-30-1 provides the overall guidance for the initial measurement of capital projects.

Excerpt from ASC 360-10-30-1

Paragraph 835-20-05-1 states that the historical cost of acquiring an asset includes the costs necessarily incurred to bring it to the condition and location necessary for its intended use.

Costs incurred during the construction of an asset that are directly attributable to its construction should be capitalized. U.S. GAAP does not currently include any specific guidance on capitalization policies for facilities constructed for a reporting entity's own use. In 2001, the Financial Reporting Executive Committee of the AICPA (FinREC) issued a proposed Statement of Position, *Accounting for Certain Costs and Activities Related to Property, Plant, and Equipment*. FinREC approved this proposed SOP (referred to herein as the proposed PP&E SOP) in 2003 subject to the FASB's clearance; however, it was not approved for issuance by the FASB and therefore never issued in final form. Nevertheless, the proposed PP&E SOP is often referred to for guidance on cost capitalization. Many of the concepts in the proposed PP&E SOP related to the capitalization of costs of an asset constructed for a reporting entity's own use continue to reflect current practice regarding the appropriate accounting treatment for these costs.

In addition, as discussed in UP 2.5.1.2, most generating stations, transmission lines, and similar assets are integral equipment and meet the definition of real estate. ASC 970 includes incremental guidance on capitalizing the costs of real estate developed for sale or rental. That guidance explicitly does not apply to facilities constructed for a reporting entity's own use. However, in the absence of other authoritative guidance, utilities and power companies often apply the guidance in ASC 970 by analogy in developing overall capitalization policies. See UP 12.2.2 for information on specific considerations for capital projects built for sale or rental, such as certain power plants built in connection with a long-term power purchase agreement.

The proposed PP&E SOP identified four phases where costs may be incurred related to plant assets: the preliminary phase, the pre-acquisition phase, the construction phase, and the in-service phase. The following sections discuss capitalization considerations through the time when property, plant, and equipment is placed in service.

12.2.1.1 Preliminary phase

The preliminary phase occurs before construction of the project is probable. ASC 720, *Other Expenses* (ASC 720), addresses costs associated with the start-up of a new facility and states that such costs should be expensed as incurred, with limited exceptions (see section on Other start-up costs below). ASC 970-340-25 also indicates that all costs should be expensed before a project is probable of being constructed, except for the cost of an option to acquire land. Options to acquire land (that do not meet the definition of a derivative) may be capitalized and should subsequently be accounted for at lower of cost or fair value, less cost to sell.

Figure 12-5 (included in UP 12.6) summarizes the accounting for some of the common types of costs incurred during all phases of construction of a plant, including the preliminary phase. ASC 720-15 includes examples of other costs that should be expensed as part of start-up or preliminary activities.

Question 12-1

How should a reporting entity assess whether a project is probable of construction?

PwC response

There is no authoritative guidance on how to determine whether a project is probable of construction. However, this topic was addressed in the proposed PP&E SOP.

Excerpt from paragraph 16 of the proposed PP&E SOP

In assessing probability, the entity should consider whether (a) its management, having the relevant authority, has implicitly or explicitly authorized and committed to funding the acquisition or construction of a specific PP&E asset, (b) the financial resources are available consistent with such authorization, and (c) the ability exists to meet the requisite local and other governmental regulations.

In the proposed PP&E SOP, the word “probable” is used consistent with the guidance in ASC 450, *Contingencies*.

Other start-up costs

ASC 720-15-15-4 discusses certain costs that may be incurred in connection with start-up activities but that are outside the scope of the guidance for start-up costs. For example, ASC 835, *Interest*, provides guidance on the accounting for costs to arrange financing for the construction of a new plant (ASC 835-30). Other costs described by ASC 720-15-15-4 that may need to be assessed as part of the start-up or construction of a power project include:

- Costs relating to mergers and acquisitions
- Costs of acquiring or constructing assets and getting them ready for their intended use (however, the cost associated with long-lived assets used to support start-up activities, such as depreciation of computers, is within the scope of the start-up cost guidance)
- Costs of acquiring or producing inventory

These types of costs typically would not be incurred until the pre-acquisition or construction phase. Nevertheless, if financing and other start-up costs outside the scope of ASC 720 are incurred during the preliminary stage, they should be accounted for in accordance with other applicable U.S. GAAP.

12.2.1.2 Pre-acquisition phase

The pre-acquisition phase begins when the acquisition or construction of specific property, plant, or equipment is probable, and prior to the acquisition or start of construction. One of the concepts addressed in the proposed PP&E SOP is the differentiation between accounting for costs that are directly identifiable and those that are an allocated or overhead cost. Directly identifiable costs should be capitalized whereas allocated and other overhead costs should be expensed as incurred. Similarly, ASC 970-340-25-3 states that costs that meet specified criteria should be capitalized once the project is probable.

Excerpt from ASC 970-340-25-3

All other costs related to a property that are incurred before the entity acquires the property, or before the entity obtains an option to acquire it, shall be capitalized if all of the following conditions are met and otherwise shall be charged to expense as incurred:

- a. The costs are directly identifiable with the specific property.
- b. The costs would be capitalized if the property were already acquired.

Consistent with this guidance, it is appropriate to capitalize direct costs during the pre-acquisition phase however, overhead and allocated costs should be expensed. Figure 12-5 (included at the end of this chapter) summarizes the accounting for common costs incurred by utilities and power companies during all stages of construction, including the pre-acquisition phase. Pre-acquisition costs should be reclassified to construction work in progress once construction begins. If construction is no longer probable, the reporting entity should consider whether an impairment loss should be recorded. If the project will be abandoned, the costs should be recorded at the lower of cost or fair value, less cost to sell. In such cases, the fair value less cost to sell is likely to be zero.

12.2.1.3 Construction phase

During the construction phase, a reporting entity should capitalize direct and incremental costs of construction in accordance with its capitalization policies. In general, indirect costs should continue to be expensed during construction. However, as further discussed in UP 12.2.2, ASC 970 provides specific guidance for the construction of real estate assets for sale or rental whereby certain overhead costs may be capitalized. In addition, regulated utilities may be able to include construction-related costs in rate base that would otherwise be expensed. To capitalize such costs, a regulated utility should ensure that it is probable such amounts will be included in future rate base (see UP 18.2).

Figure 12-5 (included at the end of this chapter) summarizes the accounting for costs incurred during all phases of construction of a power or utility project constructed for a reporting entity's own use. The following sections discuss specific additional considerations for certain of the costs that may be incurred during construction. See

UP 12.2.2 for incremental considerations for a reporting entity constructing a project for sale or rental.

Question 12-2

How do contributions received from developers or others impact the cost of plant?

PwC response

The accounting will depend on the type of payment received and varies by type of utility.

Utilities and power companies may receive amounts known as contributions in aid of construction (CIAC) that are generally intended to defray all or a portion of the costs of building or extending existing facilities. CIAC is a permanent contribution and in practice, electric and gas utilities record CIAC received as a reduction of the cost basis of plant. This concept is consistent with the Federal Energy Regulatory Commission's accounting requirements and with a regulated utility's ratemaking treatment, because rate base is generally determined net of CIAC received.

Utilities and power companies also may receive construction advances from developers. Such amounts may be refunded to the developers once the development meets certain service milestones (e.g., number of customers added, volume of commodity delivered); amounts are retained if the milestones are not met in a specified time period. Advances are generally recorded as a liability until refunded or until the milestone period lapses. If the milestone period lapses, and the amounts are retained by the utility, the construction advances are usually reclassified to reduce the related plant balance.

Water utilities may also receive CIAC; however, industry practice usually is to record CIAC as a liability and amortize over the useful life of the related asset.

Contributions made

Municipalities and other government entities sometimes require entities to make charitable contributions or donations as a condition of obtaining a construction permit. For example, the government may require the construction of additional assets or infrastructure that are unrelated to the project. ASC 720-25 defines contributions of cash and other assets.

Partial definition from ASC 720-25-20

Contribution: An unconditional transfer of cash or other assets to an entity or a settlement or cancellation of its liabilities in a voluntary nonreciprocal transfer by another entity acting other than as an owner. Those characteristics distinguish contributions from exchange transactions, which are reciprocal transfers in which each party receives and sacrifices approximately equal value. . . . In a contribution transaction, the value, if any, returned to the resource provider is incidental to potential public benefits.

Contributions should be expensed in the period made, unless the contribution is in substance the purchase of a good or service. Payments made or other services provided to a municipality or governmental entity to obtain a permit, zoning change, or other licenses necessary for construction are not contributions. Such amounts are being paid in exchange for the ability to construct a facility (i.e., they are reciprocal). Therefore, if the payment is made once the project is probable or is in construction and can be directly identified with the receipt of the permit or license, capitalization of the payment as part of the plant asset is generally appropriate.

Similarly, an entity may be required to make certain commitments in order to obtain Federal Energy Regulatory Commission (FERC) operating licenses or as part of the negotiation for a license renewal. These may include commitments for capital related expenditures (e.g., pledges for plant improvements that will improve the environmental impact of the facility) or expense-type costs (e.g., commitments to fund environmental clean-up programs or perform remediation). Improvements to facilities made as part of the response to the negotiation for a FERC license may still be capitalized as part of plant provided that they meet the criteria for capitalization in ASC 360.

For “expense-type costs,” the entity is committed to pay the expense in conjunction with the attainment of the license or license renewal. Accordingly, these commitments meet the criteria for liability recognition under ASC 405 and the discounted value of the obligations should be recognized in the financial statements. As such costs were agreed to in consideration of the benefit of operating the facility, the offset to the liability may be recorded as an intangible asset in accordance with ASC 350, and the asset would be amortized over the license period.

Capitalized interest

Unregulated entities should capitalize interest during construction in accordance with ASC 835. In addition, ARM 4740 provides guidance on capitalizing interest for reporting entities in general, including the following topics:

- Qualifying assets
- Capitalization rate and eligible expenditures
- Capitalization period
- Financing through tax-exempt borrowings, such as pollution control bonds
- Impact of derivatives on capitalization

Regulated utilities should capitalize allowance for funds used during construction (AFUDC) during the capitalization period, if allowed by the regulator. See UP 18.3 for further information on recording AFUDC.

Test power

During the testing phase of a new plant, the facility will produce power that may be sold as “test power” under a related power purchase agreement, and delivered to the facility owner’s customers, or sold to the market. In accordance with ASC 360-10-30-1, the historical cost of an asset includes “the costs necessarily incurred to bring it to the condition and location necessary for its intended use.”

Amounts to be capitalized include eligible costs incurred prior to the commercial operation date (see UP 12.2.5). Costs during the testing phase are part of the preparation of the plant for its intended use; therefore, the cost to generate test power should be incorporated as part of the initial measurement of the capitalized cost of the plant.

Question 12-3

How should a reporting entity determine the earnings and related expense, if any, for test power?

PwC response

The accounting literature does not directly address the calculation of amounts earned and expenses associated with test power. In some situations, such as in the case of a company with multiple plants and customers, it may be difficult to directly attribute certain megawatt-hour sales to the test power. In other cases, there may be contractual cash flows specifically related to the plant and any test power produced.

The FERC Uniform System of Accounts, Electric Plant Instructions, 3.A(18)(a) and (18)(b) provides a framework for test power for utilities subject to its jurisdiction. In accordance with these requirements, the amount earned from sales that is credited to plant should equal the contractual amount, if applicable. Otherwise, it should be the fair value of the power. The related expense is the incremental cost of producing and delivering the power. In practice, the amount recorded is usually the contractual amount or the market price of power during the test period (as applicable), net of any incremental fuel and transmission costs.

This guidance is specific to FERC-regulated utilities, but we believe other utilities and power companies can follow the same approach. There also may be other methods of calculating amounts earned and related expense that are appropriate in the circumstances.

Question 12-4

Should amounts received from the sale of test power be included as a reduction of the capitalized construction costs?

PwC response

Yes. When testing a facility, a reporting entity typically will sell the test power. ASC 360-10-30-1 and 30-2 acknowledge that the “activities” required to complete construction may extend over a period of time.

Excerpt from ASC 360-10-20

Activities: The term activities is to be construed broadly. It encompasses physical construction of the asset. In addition, it includes all the steps required to prepare the asset for its intended use. For example, it includes administrative and technical activities during the preconstruction stage, such as the development of plans or the process of obtaining permits from governmental authorities. It also includes activities undertaken after construction has begun in order to overcome unforeseen obstacles, such as technical problems, labor disputes, or litigation.

Amounts received for testing power are incidental to the facility’s operations because they are earned prior to the start of commercial operation. The process of producing and selling test power is one of the steps required to prepare the asset for its intended use. Therefore, consistent with the definition of activities and the requirements of ASC 360-10-20, a reporting entity should record amounts received as a result of the sale of the test power, net of any incremental fuel or other incremental production costs, as a reduction of the construction work in progress balance. Only power sold after the commercial operation date should be recorded as revenue.

Interconnection costs

To provide power to its customers, a power plant requires an interconnection between the generating facility and the transmission owner’s transmission system. During the construction phase of a generation facility, the developer of the facility may be required to construct or fund the development of an interconnection to the transmission system, but the transmission system owner may retain ownership of the interconnection. Classification of the costs associated with the interconnection is addressed in UP 21.12.

12.2.2 Construction for sale or rental

In addition to the general considerations for capitalization discussed in UP 12.2.1, reporting entities constructing assets for sale or rental should consider the additional guidance provided by ASC 970-360. Factors to consider in assessing whether a plant was built for sale or rental are summarized in Figure 12-1.

Figure 12-1

Factors indicating whether a plant was constructed for sale or rental

Evidence supporting construction for sale or rental	Evidence supporting construction for a reporting entity's own use
<ul style="list-style-type: none"> □ Facility is subject to lease through a long-term power purchase agreement □ Power purchase agreement was signed as part of the initial design of the facility (e.g., as a condition of financing) □ All or substantially all of the capital costs will be recovered through a power purchase agreement □ Plant will be sold or leased again at the end of the lease term □ Project is constructed for purpose of immediate sale; signed sales agreement is in place 	<ul style="list-style-type: none"> □ Facility will be operated to serve retail customers or to sell into the power markets □ Facility is subject to only a short-term lease (typically less than five years) with no expectation to continue leasing □ Recovery of costs is expected through sales of power to the reporting entity's retail customers □ Absence of a long-term power purchase agreement during initial construction □ Facility is designed for the owner's use

All of the factors included in Figure 12-1 are not required to be present in order to conclude that a facility was constructed for sale or rental; however, to reach such a conclusion, a long-term lease or sales agreement should generally be part of the initial design of the facility. The existence of a short-term lease could also result in a conclusion that construction is for the purpose of sale or rental if the reporting entity has the intent and ability to renew the lease or subsequently enter into a similar agreement with another party. If a reporting entity determines that a facility was constructed for sale or rental, the accounting for indirect costs and ground lease rentals should be considered during the pre-acquisition (if construction is probable) and construction phases.

Indirect costs

In accordance with ASC 970-360-25-3, indirect project costs that relate to several projects should be capitalized and allocated to the projects to which the costs relate.

Definition from ASC 970-360-20

Indirect Project Costs: Costs incurred after the acquisition of the property, such as construction administration (for example, the costs associated with a field office at a project site and the administrative personnel that staff the office), legal fees, and various office costs, that clearly relate to projects under development or construction. Examples of office costs that may be considered indirect project costs are cost accounting, design, and other departments providing services that are clearly related to real estate projects.

Therefore, reporting entities constructing property for sale or rental should have specific policies for accumulation and capitalization of qualifying indirect costs.

Ground lease expense

ASC 840-20-25-11 provides specific guidance on the accounting for ground lease expense by a lessee during construction and prohibits an entity from capitalizing such amounts in property constructed for an entity's own use. However, this guidance is not applicable to real estate projects constructed for the purpose of sale or rental. ASC 970 does not explicitly address the accounting for ground lease costs during construction of a real estate project; however, it permits the capitalization of direct and indirect costs. Consistent with this guidance, projects built for sale or rental normally include ground lease expense capitalized during the construction period. Such treatment would not be applicable for property being constructed for a reporting entity's own use pursuant to ASC 840-20-25-11.

12.2.3 *Determining components*

Components are identifiable units of property—comprising individual items or a group of individual items—that have an economic life greater than one year. A reporting entity should establish a policy for how components are determined; this will have a significant impact on future depreciation, major maintenance policies, replacements, and retirements. For example, consider the following policies for a newly constructed power plant:

□ *Multiple components*

The reporting entity could separate a power plant into multiple components (e.g., establishing lives for turbines that are different from the rest of the plant). The individual components would be depreciated over their respective lives. Replacements would result in retirement of the existing component and capitalization of the cost of the new component.

□ *One component*

The reporting entity could define the entire power plant as one unit of property. In such case, the entire plant would be depreciated using the composite method over the plant's useful life. Major maintenance, including replacements of individual parts, would be expensed as incurred.

There is a range of industry practice in developing policies for components; however, reporting entities generally should be as specific as possible in the identification of components. There also may be additional considerations for regulated utilities as a result of the regulator's requirements. A reporting entity should apply its policy consistently to similar properties.

12.2.4 *Capital spares*

Property, plant, and equipment consists of long-lived tangible assets used to create and distribute a reporting entity's products and services and includes machinery and

equipment. It is not unusual for utilities or power companies to acquire capital spare parts and hold them in storage prior to their installation or addition to operating plant. Such parts are held on hand if the lead time to acquire new parts is long, or contractual maintenance agreements require the reporting entity to maintain such parts on hand.

The accounting guidance does not define capital spares; however, in determining whether parts are capital spares, industry practice is to consider whether the parts possess the following characteristics:

- Long lead time to procure
- Costly
- Vital to the continued operation of the facility
- Used for emergency replacement only
- Require customization

In addition, the Internal Revenue Services' Revenue Ruling 81-185¹ provides definitive guidelines on emergency spare parts. Although this guidance is applicable only for income tax purposes, the points outlined are a reference for reporting entities developing an internal policy. Capital spares may be classified as part of the plant balance prior to use in the plant. The parts would be expensed or capitalized as plant in service when used, depending on the reporting entity's policies for components and major maintenance (see UP 12.2.3 and UP 12.4.1, respectively). In addition, depreciation on capital spares prior to being put in use would depend on the entity's policy for componentization and other factors.

12.2.5 Commercial operation date

The date on which a plant is considered ready for its intended use is often referred to as the commercial operation date (COD) or the placed-in-service date. Figure 12-2 summarizes industry practice in determining the COD:

Figure 12-2
Determining the commercial operation date

Type of plant	Considerations
Fossil fuel	COD is usually defined as the point at which the plant has been fully operational for 48 continuous hours. This definition has become common in practice because it parallels definitions in typical warranty contracts from turbine manufacturers.

¹ Rev. Rul. 81-185, 1981-2 C.B. 59, Depreciation; Public Utility; Major Standby Emergency Spare Parts.

Type of plant	Considerations
Nuclear	<p>Nuclear generating plants operate under the jurisdiction of the Nuclear Regulatory Commission (NRC). The NRC licensing process usually involves two dates. The first is the granting of a low-power license, usually representing the right to operate at five percent of rated capacity. At this point, steam is produced but no power is generated. The second is the granting of a full-power license, which occurs after completion of the appropriate testing.</p> <p>A common scenario for nuclear plants is for management to declare the COD when the plant is producing power at a minimum of 50 percent for a sustained period of time.</p>
Renewable	<p>The COD is typically the date at which the project is mechanically complete and begins delivering power.</p>

For accounting purposes, the COD is important because it is the date at which some types of costs are no longer considered capital costs (but rather become operating or maintenance costs). It is also the point at which the reporting entity begins to record depreciation expense and ceases capitalizing interest costs. In addition, the COD is often the effective date for power purchase agreements related to new construction.

There is no formal accounting guidance on how to determine the COD. It is a point in time, declared by management, at which all testing and commissioning for the unit has been completed and the project is deemed available for dispatch. There are, however, some customary industry practices for determining the COD, as summarized in Figure 12-2.

In addition to the considerations in Figure 12-2, engineering, procurement, and construction contracts or power purchase agreements may define the point at which commercial operation is reached.

12.3 Depreciation

ASC 360-10-35-4 provides guidance on the timing and method of recognition of depreciation expense.

Excerpt from ASC 360-10-35-4

The cost of a productive facility is one of the costs of the services it renders during its useful economic life. Generally accepted accounting principles (GAAP) require that this cost be spread over the expected useful life of the facility in such a way as to allocate it as equitably as possible to the periods during which services are obtained from the use of the facility. This procedure is known as depreciation accounting, a system of accounting which aims to distribute the cost or other basic value of tangible capital assets, less salvage (if any), over the estimated useful life of the unit (which may be a group of assets) in a systematic and rational manner.

Plant accounting requires adoption of a method of depreciation and estimation of the useful lives and related salvage values of the assets to be depreciated. An estimate of useful life not only considers the economic life of the asset, but also the remaining life of the asset to the reporting entity. If an operating license or permit is required to use an asset, the remaining useful life will often be the same as the remaining term of the operating license or permit. Similarly, if a plant is subject to a ground lease, the useful life should not exceed the lease term.

There are several methods of depreciation that can be used, including straight-line, accelerated methods (such as “sum-of-the-years-digits” and declining-balance methods), and units-of-production methods. In addition, due to the nature of utility plant and power generation assets, the group and composite methods of depreciation are commonly applied in depreciating multiple assets or asset groups. This section discusses certain aspects of the group and composite methods of depreciation. See also UP 18.6 for further information on depreciation for regulated utilities.

12.3.1 Group and composite depreciation

Multiple-asset groups may be depreciated in one of two ways: the “group” method and the “composite” method. The group method is typically used for groups of assets that are largely homogeneous and have approximately the same useful lives. The composite approach is used when the assets are heterogeneous and have different lives. When applied to a largely homogeneous population, the group method more closely approximates a single-unit depreciation profile because the dispersion from the average useful life is not meaningful. Under both methods, a reporting entity depreciates the balance over the average life of the assets in the group.

Regulated utilities often apply the group method to fixed assets such as utility poles and other components of their transmission and distribution systems, which are too numerous and of individually low-value to practically track on an individual basis. Reporting entities often apply the composite method for component parts of larger assets such as power plants, which also contain numerous components and parts that are impractical to track separately. To apply the group or composite method of depreciation, a reporting entity should have quantitative data to support the method, such as expected useful life of the assets, the dispersion of useful lives from the average for group depreciation, and the calculations supporting the weighted average depreciation rate for the composite method. Periodic studies should also be performed to support ongoing use of the group or composite method.

In general, and unlike the unitary convention of accounting for fixed assets, neither the group nor composite method of depreciation results in the recognition of a gain or loss upon the retirement of an asset. If an asset is retired before or after the average service life of the group is reached, the resulting gain or loss is included in the accumulated depreciation account. The amount recorded in accumulated depreciation is the difference between original cost and cash received. The result is that the gain or loss on disposal remains in accumulated depreciation; no gain or loss on disposal is recorded in earnings. The group and composite methods simplify the bookkeeping process and tend to smooth any potential differences caused by over- or under-depreciation. As a result, periodic income is not distorted by significant gains or losses

on disposals of assets. Refer to example 12-1 for an illustration of the journal entries expected in this application.

Question 12-5

Is it acceptable to switch from the unitary method of depreciation to a group or composite method?

PwC response

Generally, no. ASC 250-10-45-18 states that a change in method of depreciation is considered a change in accounting estimate effected by a change in accounting principle. “The new depreciation method is adopted in partial or complete recognition of a change in the estimated future benefits inherent in the asset, the pattern of consumption of those benefits, or the information available to the reporting entity about those benefits.” In such circumstances, the effect of the change in accounting principle, or the method of applying it, is considered inseparable from the effect of the change in accounting estimate.

Like other changes in accounting principles, a change in accounting estimate that is effected by a change in accounting principle is permitted only if the new accounting principle is preferable. Absent such a conclusion, a reporting entity cannot modify its depreciation method(s). Although the composite and group depreciation methods are an acceptable method, the unitary method is generally considered preferable. Therefore, we generally do not believe it would be appropriate to change from this method to the group or composite method.

See BC 10.3.2 for further information on changes in depreciation methods.

Question 12-6

Are unregulated entities permitted to use the composite or group method of depreciation?

PwC response

Yes. Both of these conventions are considered acceptable pursuant to GAAP. The composite or group method of depreciation may be applied by any reporting entity if it is selected at the time the asset is placed in service. In addition, certain entities may use more than one method of depreciation, such as applying unit depreciation to fixed assets with large unit costs while the group method is applied to other types of assets with lower unit costs.

Question 12-7

How often should a reporting entity perform a depreciation study when applying the composite or group method of depreciation?

PwC response

It depends. Reporting entities that apply the group or composite method of depreciation should obtain updated depreciation studies on a regular basis. The frequency of the study is often a function of the extent of changes since the last study. For example, more frequent or immediate studies may be appropriate in circumstances when a reporting entity experiences a significant and unplanned level of retirements. Significant and unplanned retirements may change the key characteristics of the group of assets (e.g., average age of the assets, average remaining life of the assets) such that the previous depreciation rates may no longer be a reasonable estimate of the assets' remaining lives. Periodic depreciation studies with regular updates should help to ensure that depreciation is recorded over a reasonably accurate assessment of the remaining useful lives of the assets.

Question 12-8

Are gains or losses ever recognized when applying the group or composite method of depreciation?

PwC response

It depends, but generally no. We believe that a gain or loss should be recognized in earnings only when unforeseen or unexpected retirements have occurred. For example, the early retirement of an entire generating station due to storm damage would likely be considered abnormal and would result in the recognition of a loss. We believe that the occurrence of an unforeseen or unexpected retirement would be rare.

12.3.1.1 Application example—group depreciation

Example 12-1 illustrates application of the group depreciation method.

EXAMPLE 12-1**Application of the group depreciation method**

On January 1, 20X1, Rosemary Electric & Gas Company (REG) installs 10,000 new utility poles, each with an estimated useful life of 40 years (annual rate of depreciation of 2.5 percent). The original cost of purchase and installation was \$4 million (\$400 per pole), paid for in cash. At the time of installation, the expected net salvage value of the assets (expected salvage less the expected cost of removal and disposal) is \$0, resulting in a depreciable base of \$4 million. REG applies the group method of depreciation and groups all of its utility poles for purposes of calculating depreciation expense. At the end of 39 and 40 years of service, 2,500 and 7,500 utility poles, respectively, are retired and there are no proceeds from salvage.

How should REG account for the purchase, depreciation, and retirement of the utility poles?

Analysis

REG would record the following journal entries (amounts in thousands).

Year	Journal entries	Cash	Plant	Accumulated depreciation	Depreciation expense/loss
1	Record initial installation	(\$4,000)	\$4,000		
1–39	Record annual depreciation (((\$4 million / 40 years) × 39 years)			(\$3,900)	\$3,900
39	Record property retirement (2,500 poles × \$400)		(\$1,000)	\$1,000	
40	Record depreciation (((\$4 million – 1 million)*2.5%)			(\$75)	\$75
40	Record property retirement		(\$3,000)	\$2,975	\$25
		(\$4,000)	\$0	(\$0)	\$4,000

The total cost of the early retirement would be charged to accumulated depreciation, without adjustment for whether the specific property item has reached the average life. Depreciation continues on the remaining poles until they are retired. Once the group is retired in its entirety, a gain or loss may be recognized.

12.4 Maintenance, including major maintenance

Maintenance is a significant activity for utilities and power companies. Maintenance programs may involve the use of internal resources or a third-party maintenance provider. Furthermore, third-party agreements may be stand-alone service agreements or embedded in a lease. All routine maintenance should be expensed as incurred. This section focuses on the accounting for major maintenance activities, including specific considerations when the services are provided through a long-term service agreement or lease.

12.4.1 Accounting for major maintenance

The AICPA Audit and Accounting Guide, *Airlines* (the Airline Guide), provides the principal source of authoritative guidance on accounting for major maintenance activities. A limited portion of this guidance was codified in ASC 908, *Airlines* (ASC 908). ASC 908-360-25-2 states that there are three acceptable methods of accounting for major maintenance, as highlighted in Figure 12-3.

Figure 12-3
Accounting for major maintenance activities

Method	Guidance
Direct expensing	Cost is recognized as expense as it is incurred.
Deferral	The actual cost of each overhaul is capitalized and amortized to the next overhaul.
Built-in overhaul	The built-in overhaul method is based on segregation of the initial cost of an asset into the components that will be replaced in the next overhaul and those that will be used over the remaining useful life. The components that will be replaced in the next overhaul are depreciated over the life to the next expected overhaul date. Once the first overhaul occurs, the accounting for major maintenance is similar to the deferral method.

The use of the accrue-in-advance method (where major maintenance costs are accrued ahead of the maintenance taking place) is prohibited in annual and interim financial statements. See the Airline Guide, paragraphs 4.113 through 4.118, for additional information on application of the three acceptable methods.

In the Airline Guide, FinREC states its belief that the direct expense (expense as incurred) method is preferable to the other methods, although any of the three methods may generally be used (see Question 12-9). The method used to recognize major maintenance expense is an accounting policy election that should be applied consistently for all similar projects.

Question 12-9

Can the deferral or built-in overhaul methods of accounting for major maintenance be used when the group or composite method of depreciation is used?

PwC response

No. As discussed in UP 12.3.1, reporting entities may apply a group or composite method of depreciation, in which case depreciation is applied to a pool of assets based on the average useful life of the assets. The application of the deferral or built-in overhaul method of accounting for major maintenance requires separately accounting for maintenance costs associated with component assets. Once the group or composite method of depreciation is applied, individual assets lose their individual identity and the pool is in effect one component. Therefore, any amounts related to major maintenance would need to be accounted for using the expense as incurred method.

12.4.2 Long-term service agreements

Concurrent with the construction or acquisition of generating assets, many utilities and power companies enter into long-term service agreements with third-party providers to perform major maintenance. These agreements usually involve major maintenance services (including refurbishment or replacement of capital parts) as well as routine maintenance activities. Generally, payments under a long-term service agreement (LTSA) are made on a recurring basis and maintenance is performed at scheduled dates in accordance with an agreed-upon milestone schedule.

LTSAs common in the industry typically pass through to the customer the cost of parts, equipment, and specified costs, or otherwise share the risk between the service provider and the plant owner. This feature in an LTSA is a funding or cash flow mechanism and will not drive the timing of expense recognition. Instead, the reporting entity's major maintenance accounting should be determined based on its overall policy for similar plants. Some long-term service agreements are based on a fixed price per megawatt-hour or other pricing mechanism that fully transfers risk to the service provider. The accounting for this type of contract may vary from the general model. These forms of LTSAs are discussed in the following sections.

12.4.2.1 Accounting for variable price long-term service agreements

Amounts related to routine maintenance should be expensed as incurred. Amounts related to major maintenance should be recorded in accordance with the reporting entity's policy for major maintenance. Any differences between the expense recognized and payments made should be recorded as a prepaid or a payable (e.g., a payable would be recorded if services are provided before related payments are made).

Often, an LTSA includes multiple price components, such as a fixed monthly fee, variable monthly fees, and milestone payments based on hours. These components typically cover major service events and monthly routine services to monitor and manage the performance of the covered equipment. The service provider may classify the costs into major categories such as capital parts, consumable parts, field services, component repair services, and other contractual services. In some circumstances, it may be difficult to determine the cost of the different services and the appropriate allocation between routine and major maintenance. To properly account for maintenance services, a reporting entity should work with the service provider to understand how the payments relate to the products and services provided under the LTSA. This information may be used to classify the costs between routine and major maintenance activities. Prior experience with similar plants or agreements may also provide information to be used to allocate costs between routine and major maintenance services.

Application examples—long-term service agreement

The following examples provide guidance on how reporting entities should account for maintenance and capital spares obtained through an LTSA. Example 12-3 illustrates the accounting for an LTSA that includes capital spares.

EXAMPLE 12-2

Accounting for a long-term service agreement

Ivy Power Producers (IPP) enters into a 15-year, long-term service agreement with Service Provider for planned maintenance services on the natural gas and steam turbine generating units at the Maple Generating Station. The service agreement calls for a fixed monthly fee of \$50,000 and other payments to be made as follows:

- Variable monthly turbine fee based on fired hours estimated to be \$100,000 per month.
- A payment of \$5,000,000 at each date a milestone is achieved based on fired hours.

IPP determines that the fixed monthly fee is entirely related to routine maintenance, based on discussion with and review of documentation provided by Service Provider. IPP also determines that the variable monthly turbine fee includes an expense maintenance component (amount related to routine maintenance) of \$25,000 and capitalizable maintenance components (including labor and parts) of \$75,000. Finally, IPP concludes that the milestone payments are capital in nature and relate solely to major maintenance activities.

How should IPP account for the payments made to Service Provider?

Analysis

The routine maintenance expenses (the monthly fee and the expense portion of the variable turbine fee) would be expensed as paid. The capital component of the monthly fee and the milestone payments could be accounted for under any of the permitted methods for major maintenance as follows:

- *Direct expensing*

IPP would establish a prepaid asset as the variable turbine monthly (capital portion only) and milestone payments are made and would recognize the expense when the major maintenance is performed. At the time of major maintenance, rather than expensing the entirety of the payment, it may be appropriate to classify any portion of payments relating to prepaid capital parts within materials and supplies inventory until the parts are used.

- *Deferral method*

IPP would record an asset as the variable turbine monthly (capital portion only) and milestone payments are made, and would begin to amortize the amounts after the first major maintenance event occurs.

- *Built-in overhaul method*

Upon purchase of components of the Maple Generating Station subject to periodic maintenance, a portion of the purchase price would be allocated to maintenance

and amortized through the date of the initial overhaul. The accounting for the payments under the LTSA would then follow the deferral method.

Under all three scenarios, IPP would consider whether it is receiving any maintenance services in advance of payments made or whether amounts represent prepayments for future services. For example, this may arise if the milestone payments are higher or lower than the underlying cost of the maintenance provided. In such cases, IPP would estimate the actual amount of expense and record a prepaid or a payable for the difference from its actual payments.

EXAMPLE 12-3

Accounting for a long-term service agreement that includes capital spares

Ivy Power Producers (IPP) has a contract with a maintenance provider to perform major maintenance inspections on the Camellia Generating Station after certain fired-hour intervals. The major maintenance provider is a subsidiary of the original equipment manufacturer, and the contract requires that IPP purchase a portfolio of capital spares to be kept “on the shelf” in storage during the period of the contract for use during major maintenance.

The parts may not be resold or used for any purpose other than major maintenance activities. IPP will have title to the parts when purchased, but title to any remaining parts in storage when the maintenance contract expires will transfer to the equipment manufacturer.

How should IPP account for the payment made for capital spares?

Analysis

The cost of the capital spare parts would be capitalized. As IPP has to return any unused capital spares at the expiration of the contract, the payment for capital spares represents an additional service payment and should be amortized over the term of the contract.

12.4.2.2 Accounting for fixed-price long-term service agreements

Stand-alone LTSAs typical in the industry usually involve pass-through of certain specific costs to the owner of the facility or otherwise share price risk between the parties to the agreement. However, some LTSAs have a fixed price over a period of time or a fixed price per megawatt-hour generated. This type of agreement may transfer all risk of providing maintenance services to the service provider.

The Airline Guide discusses similar agreements in the airline industry (known as power-by-the-hour (PBTH) contracts). Although the type of contract is specific to the airline industry, the agreements, and the related issues, are similar to those encountered by utilities and power companies. Therefore, in the absence of other authoritative guidance, the framework set forth in the Airline Guide is helpful in evaluating the appropriate accounting.

Excerpt from paragraph 4.123 of the AICPA Audit and Accounting Guide, Airlines

FinREC believes the issues relating to PBTH contracts and other similar arrangements with independent maintenance and repair providers include determining whether risk has been transferred to the service provider. The risk transfer criteria discussed in this section provide a framework for determining whether there is a transfer of risk. If the contract transfers risk, FinREC believes the airline should recognize maintenance expense in accordance with the PBTH contract, as opposed to following its maintenance accounting policy. In these situations, FinREC believes there is a presumption that the expense should be recognized at a level rate per hour during the minimum, noncancelable term of the PBTH agreement. That presumption could be overcome by evidence that the level of service effort varies over time, consistent with the variations in the payment pattern under the PBTH contract.

The key criteria in evaluating whether risk has transferred are discussed in paragraph 4.125 of the Airline Guide and summarized in Figure 12-4.

Figure 12-4
Transfer of risk criteria

Criterion	Guidance
True-ups	<ul style="list-style-type: none"> □ The service provider absorbs substantially all of the variability of the cost of maintenance. □ A contract that provides for true-up payments to cover actual costs incurred by the service provider would not result in risk transfer.
Contract adjustment provisions	<ul style="list-style-type: none"> □ Contracts with adjustments for a change in scope may still transfer risk as long as they are not merely true-up adjustments for the service provider's actual cost experience. □ Annual or periodic inflation adjustments are also permitted, as well as increases tied to certain performance criteria (as long as adjustments tied to performance are capped or otherwise limited).
Termination provisions	<ul style="list-style-type: none"> □ Buy-out provisions that provide for cost recovery on termination would not transfer risk. □ Termination provisions need to be substantive enough to prevent either party from exiting at their discretion or risk is not transferred.

If the reporting entity concludes that risk is transferred, the maintenance costs should be accounted for in accordance with the terms of the agreement instead of the reporting entity's normal policy for maintenance. In developing an expense recognition policy for this type of contract, there is a presumption that expense should be recognized on a level rate based on usage; however, this presumption may be overcome if there is evidence that the level of service effort varies over time and that

changes in expense are reflective of changes in service. Changes in contractual rates based on an index, such as Consumer Price Index, or that cannot be reliably determined at the start of the contract would not be levelized, except to the extent there is a specified minimum increase.

We believe the model discussed in the Airline Guide is reflective of the underlying economics of a fixed-price maintenance agreement and that it is appropriate for utilities and power companies to apply it in evaluating and accounting for fixed-price LTSAs.

12.4.3 Maintenance included in leasing arrangements

Most power purchase agreements accounted for as leases implicitly include operations and maintenance services. Maintenance services are an executory cost of the lease or are considered “other services” (a nonlease element). See UP 2.3 for further information on this determination and potential cost allocation considerations. In either case, the maintenance services are not part of the minimum lease payments and would not be part of the lease accounting. Instead, a lessee should follow the appropriate LTSA model in determining how to recognize expense. In many cases, these agreements will meet the risk-transfer criteria and will be subject to the fixed-price recognition model discussed in UP 12.4.2.2. This recognition pattern will frequently be similar to the pattern of lease expense recognition under an operating lease.

12.4.3.1 Maintenance deposits under leasing arrangements

ASC 840-10-25-39B addresses how a lessee should account for maintenance deposits paid under an arrangement accounted for as a lease in cases where that deposit will be refunded only if the lessee performs certain specified maintenance activities. In some cases, these prepayments for maintenance may be termed in different ways, including “maintenance reserves” or “supplemental rent.” ASC 840-10-25-39B applies to all types of deposits that are substantively and contractually related to the maintenance of the leased asset.

Maintenance deposits should be accounted for as deposit assets by lessees. Maintenance costs should be expensed or capitalized as appropriate when the underlying maintenance is performed. If the lessee determines that an amount on deposit is less than probable of being returned, it should be recognized as additional expense at that time. For lessors, maintenance deposits should be recorded as liabilities until the deposits are refunded or recognized in income, which would occur upon the expiration of the contract.

12.5 Impairment

ASC 360 requires that a long-lived asset (asset group) be tested for impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. Changes in power markets, evolving power plant technologies, and the persistent increase in environmental requirements for fossil fuels have all driven a continued focus on the recoverability of plant assets and the need for robust impairment evaluations. Reporting entities should monitor such changes and the impact on their power plants and other long-lived assets on an ongoing basis to

determine whether there has been a trigger requiring an impairment analysis. ASC 360-10-35-21 also provides examples of six specific indicators that may indicate impairment, including a decrease in market prices, adverse change in physical condition, or adverse changes in legal factors or the business climate.

See BC 10.4 for a comprehensive discussion of impairment issues. This section supplements BC 10 and addresses certain industry-specific issues related to applying the ASC 360 framework to assets held and used. It also addresses certain matters associated with assets held for sale. See UP 18.7 for information about disallowances and abandonment issues related to regulated utility plant.

12.5.1 Long-lived assets to be held and used

The first step in testing long-lived assets held and used for impairment is determining the unit of account. ASC 360 provides specific guidance on how to consider assets and asset groups when evaluating long-lived assets that are to be held and used.

Excerpt from ASC 360-10-35-23

For purposes of recognition and measurement of an impairment loss, a long-lived asset or assets shall be grouped with other assets and liabilities at the lowest level for which identifiable cash flows are largely independent of the cash flows of other assets and liabilities.

Determining the appropriate unit of account (whether a stand-alone asset or asset group) is a key aspect in testing and measuring impairment of long-lived assets held and used. The determination involves a significant amount of judgment, and all relevant facts and circumstances should be considered as described in ASC 360-10-55-35.

ASC 360-10-55-35

Varying facts and circumstances will inevitably justify different groupings of assets for impairment review. While grouping at the lowest level for which there are identifiable cash flows for recognition and measurement of an impairment loss is understood, determining that lowest level requires considerable judgment.

Characteristics specific to the operations of the reporting entity and its business environment should be assessed in evaluating the lowest level of identifiable cash flows. Factors to consider include:

- Are there any interdependencies in revenue-generating activities?
Interdependencies may result from regulatory, legal, or contractual restrictions or otherwise arise based on whether and how the reporting entity manages and operates its assets as a group.
- Are the assets used together in vertically integrated operations?
- Do the assets have a shared cost structure? If a particular asset group has significant shared operations and cash flows, it may be necessary to group assets

at a higher level. However, the existence of shared service activities alone would not necessarily require grouping assets if the shared services are not considered significant.

The determination of asset groups may be particularly complex when considering utility and power generation assets such as power plants, transmission assets, or natural gas distribution assets. These assets are often interdependent due to contractual or other requirements. ASC 360-10-55-36 (Example 4) illustrates the evaluation for an entity that operates bus routes, which has considerations similar to those relevant for utility and power assets.

Excerpt from ASC 360-10-55-36

In this Example, an entity operates a bus entity that provides service under contract with a municipality that requires minimum service on each of five separate routes. Assets devoted to serving each route and the cash flows from each route are discrete. One of the routes operates at a significant deficit that results in the inability to recover the carrying amounts of the dedicated assets. The five bus routes would be an appropriate level at which to group assets to test for and measure impairment because the entity does not have the option to curtail any one bus route.

As noted in the excerpt, depending on the facts and circumstances, it may be appropriate to group assets even if the cash flows for individual assets are identifiable.

Question 12-10

Is it appropriate to combine more than one generating plant into an asset group?

PwC response

It depends. In some cases, the lowest level of identifiable cash flows may be at the single power plant level, which would then be the asset group. This may be the case if the output from the plant is sold under a single contract and the plant is stand-alone (i.e., not considered a “must run” unit within a control area or otherwise does not have operations that are interrelated with other plants). In other cases, a power plant’s output may be used in the balancing of a system or the power plant may be part of a system (e.g., the plant provides reliability for other units in the system or is dispatched as part of a group). Furthermore, a regulator may consider a regulated utility’s power plants in combination when evaluating revenue requirements. In such cases, even if the cash flows of the plant are separately identifiable, regulatory, legal, or contractual requirements may indicate that the plant should be grouped with other plants.

Determining whether power plants should be grouped requires a thorough analysis of the environment in which the plant is dispatched; whether the output of the plant is contracted; and any other legal, contractual, and operating requirements. Reporting entities should consider similar factors in assessing the appropriate asset group for other utility or power assets, such as transmission or natural gas distribution assets.

Question 12-11

Should plant-specific power purchase agreements be combined with the related power plant(s) in an asset group when recognizing and measuring impairment?

PwC response

It depends. ASC 360-10-35-23 addresses the recognition and measurement of asset impairments and requires that assets be “grouped” and measured for impairment at the lowest level of identifiable cash flows. In the case of a plant-specific power purchase agreement, the megawatts delivered under the contract must be provided by the specified generating facility. In such cases, the agreement is interrelated with the plant (because the plant’s cash inflows are generated by the power purchase agreement) and the cash flows relating to the agreement should be included in the impairment test. If the contract meets the definition of a derivative, certain additional considerations may be relevant.

If the agreement is a derivative that is being recorded at fair value, any above or below market cash flows are already measured in the fair value of the related derivative asset or liability. Therefore, if an impairment is recorded for the asset group, no portion of any impairment loss would be allocated to the derivative contract.

If the contract is designated in a hedge of a forecasted transaction (e.g., an all-in-one hedge of forecasted sales from the plant), ASC 815-30-35-42 requires that the related expected cash flows be excluded from the impairment analysis (see also DH 6.7). In addition, as required by ASC 815-30-35-43, any amounts previously deferred in accumulated other comprehensive income would be released to the income statement.

Question 12-12

What would the cost basis be after an impairment loss is recognized?

PwC response

ASC 360-10-35-20 states in part that “if an impairment loss is recognized, the adjusted carrying amount of a long-lived asset shall be its new cost basis.” The new cost basis is then depreciated over the remaining useful life of the asset. Additionally, the useful life of an asset should be periodically reassessed.

12.5.1.1 Application examples—determining the asset group for power plants

The following examples illustrate the factors to consider in determining asset groupings for power plants.

EXAMPLE 12-4

Determining the asset group for a group of power plants—interrelated operations

Ivy Power Producers (IPP) owns numerous power plants located in the midwestern and northeastern United States, including nuclear, natural gas, renewable, and coal plants. The facilities are located in five independently operated control areas.

The plants in each control area are managed as a group of assets, including common hedging strategies, budgeting, dispatch decisions, and fuel management. Each of the five independently operated control areas conducts an annual auction for capacity. IPP bids the output from its plants into the annual capacity auctions on a portfolio basis for each control area. In this process, IPP includes a cushion/margin within its bid in a control area (due to severe penalties for failure to provide capacity under contract). Dispatch decisions are made based on multiple factors as follows:

- Economic dispatch—plants are operated based on the lowest costs taking into account current fuel prices and expected load (there is a cost to starting up individual plants)
- Operational needs—certain plants can be ramped up and down quickly to respond to fluctuations in demand while others are typically operated as base load units (operated continuously at a consistent level of output)
- Reliability—certain plants are needed to ensure the stability of the grid and to provide power where it is needed

As a result, certain plants operate infrequently and have minimal cash flows on a stand-alone basis. IPP does not measure or allocate revenues to any individual plant. Instead, revenues are recorded and performance is evaluated at the portfolio level for each control area.

What should IPP consider to be the asset groups?

Analysis

Based on the way the plants are managed and operated (i.e., for each control area), and the measurement and allocation of revenue on a control area basis, there would be five asset groups, composed of the plants in each control area.

EXAMPLE 12-5

Determining the asset group for a group of power plants—plant-specific contract

Assume the same facts as in Example 12-4, except IPP has one renewable plant, the output of which is sold entirely under contract to Rosemary Electric & Gas Company (REG), a regulated utility located in one of IPP's control areas. The plant is in a remote location of the control area and IPP does not operate the plant as part of the overall dispatch of the system.

What should IPP consider to be the asset groups?

Analysis

Although the specific plant is located in the same control area as other IPP plants, it is directly contracted to a third party and not operated in connection with the other plants or relied upon for purposes of system reliability. Therefore, the renewable plant should be a separate asset group.

EXAMPLE 12-6

Determining the asset group for a group of power plants—revenue interdependencies due to a contractual relationship

Ivy Power Producers (IPP) owns five power plants in California. IPP has entered into a contract with the state to supply a specified amount of power and capacity, representing the majority of the output available from the five plants, to the state's regulated utilities. Under the terms of the agreement, IPP is permitted to supply the power and capacity from any of its five power plants located in the state.

What should IPP consider to be the asset groups?

Analysis

The plants are operated under contract as a group. The revenues under the contract are interrelated and the cash flows from individual plants are not independent of each other. As a result, the five plants should be considered one asset group.

12.5.2 Long-lived assets held for sale

ASC 360-10-45-9 provides six criteria, all of which should be met, for a long-lived asset (disposal) group to be classified as held for sale. The classification of a long-lived asset held for sale has many implications, including a different measurement basis and separate presentation. In addition, if an asset (or asset group) is classified as held for sale, depreciation ceases, and a reporting entity should consider whether it has a discontinued operation.

One of the criteria for evaluating whether a long-lived asset should be held for sale is the timing of the sale.

Excerpt from ASC 360-10-45-9(d)

The sale of the asset (disposal group) is probable, and transfer of the asset (disposal group) is expected to qualify for recognition as a completed sale, within one year, except as permitted by paragraph 360-10-45-11.

The FASB has provided certain exceptions to the “one-year” rule. For example, if a reporting entity were to commit to a plan to sell within a year, but parties other than the buyer could impose conditions or restrictions that would extend the completion of

the sale beyond a year, and other specified conditions are met, the reporting entity is considered to have met this criterion.

This guidance is further illustrated by an example of regulatory approval, in ASC 360-10-55-44 and 55-45.

ASC 360-10-55-45

An entity in the utility industry commits to a plan to sell a disposal group that represents a significant portion of its regulated operations. The sale will require regulatory approval, which could extend the period required to complete the sale beyond one year. Actions necessary to obtain that approval cannot be initiated until after a buyer is known and a firm purchase commitment is obtained. However, a firm purchase commitment is probable within one year. In that situation, the conditions in paragraph 360-10-45-11(a) for an exception to the one-year requirement in paragraph 360-10-45-9(d) would be met.

This example may be relevant to a potential sale by a regulated utility or other entity where regulatory approval is required. The timing requirement may still be met, even if actions of a regulator could extend the completion of the sale beyond one year.

See BC 10.4.2 for further information on evaluating whether assets meet the held for sale criteria as well as related accounting implications.

12.5.3 Insurance recoveries

A power plant may become impaired as the result of damage for which it has insurance and expects recovery of any losses incurred. Generally, a claim for a loss recovery can be recognized when a loss event has occurred and recovery is considered probable. If the claim is subject to dispute or litigation, a rebuttable presumption exists that recoverability of the claim is not probable. If the potential recovery exceeds the loss recognized in the financial statements, the amount by which recovery exceeds the loss should be accounted for as a gain contingency.

Accordingly, an entity may need to bifurcate a claim and analyze recognition for the amount up to the amount of loss previously recognized under one model and the amount in excess of the loss under another. Recognition of insurance claims for amounts where a loss has not been recognized, including recoveries exceeding losses recognized as well as business interruption insurance recoveries, should be accounted for as gain contingencies and may only be recorded when the claim is realized or realizable, which is generally when either the cash has been received or signed agreement or legally enforceable document which stipulates the terms of settlement. To the extent an entity was required to incur additional capital expenditures beyond the loss recognized, and such expenditures were subsequently recovered through insurance, such recoveries would be recorded as reductions to the plant balance. For further information regarding insurance recoveries, including gain contingencies and loss recoveries, refer to ARM 5360.11—.12.

12.6 Summary of accounting for development and construction costs

Figure 12-5 summarizes general accounting guidance for costs that are typical in utility and power construction. This summary is provided for informational purposes only and should be considered in the context of the applicable guidance and specific facts and circumstances. It should also be read in conjunction with the guidance provided in UP 12.2.

Figure 12-5
Accounting for development and construction costs

Type of cost	Phase			Considerations
	Preliminary	Pre-acquisition	Construction	
Construction labor and other direct costs of construction	Expense	Capitalize	Capitalize	Labor and related direct costs should be expensed until the project is probable. Costs that are direct and clearly incremental should be capitalized once the project is probable and during the construction phase.
Consulting fees (e.g., engineering, architectural studies)	Expense	It depends	It depends	Fees should be expensed until the project is probable. Once the project is probable, directly identifiable costs may be capitalized. The amount capitalized should be limited to those amounts directly related to the site and project selected (e.g., costs related to evaluation of potential projects or locations should be expensed).
Contribution to local community organization or other similar gift made as a precondition to obtaining necessary permits or licenses	Expense	It depends	It depends	In general, contributions should be expensed in the period made unless amounts are, in substance, the purchase of a good or service. Contributions made in exchange for a required license or permit may qualify for capitalization. See UP 12.2.1.3.
Due diligence fees	Expense	It depends	It depends	See discussion under “Consulting fees” above.

Type of cost	Phase			Considerations
	Preliminary	Pre-acquisition	Construction	
Engineering, procurement, and construction contract costs	Expense	Capitalize	Capitalize	Direct costs of construction should be capitalized. Indirect costs and overhead of the EPC contractor may also be capitalized as part of the direct costs of construction because such amounts are considered an incremental direct cost.
Feasibility studies	Expense	It depends	It depends	See discussion under “Consulting fees” above.
Ground lease expense	Expense	Expense	Generally expense	ASC 840-20-25-11 prohibits capitalization of ground lease expense by a lessee for property constructed for its own use. However, ground lease expense may be capitalized during construction of property for sale or rental. See UP 12.2.2.
Interest costs	Expense	Capitalize	Capitalize	Interest costs should be capitalized in accordance with the criteria in ASC 835-20. See UP 12.2.1.3.
Land option	Capitalize	Capitalize	Capitalize	The proposed PP&E SOP and ASC 970-340-25-3 specifically permit capitalization of land options, even during the preliminary stage when the project is not yet probable. Amounts paid should subsequently be accounted for at the lower of cost or fair value, less cost to sell.
Legal fees	Expense	It depends	It depends	See discussion under “Consulting fees” above.
Materials and supplies	Capitalize	Capitalize	Capitalize	Materials and supplies should be accounted for in accordance with the reporting entity’s policy for similar items. Amounts are usually capitalized and should be carried at the lower of cost or market. See UP 11.2.

Type of cost	Phase			Considerations
	Preliminary	Pre-acquisition	Construction	
Operating contract negotiation (e.g., fuel supply agreements, power sales agreements, operating and maintenance agreements)	Expense	Expense	Expense	Contract negotiation costs should be expensed. Although the project may not be viable without operating contracts (because, for example, a signed power sales agreement is a prerequisite for financing), these contracts are not directly related to or theoretically necessary for construction of the asset itself.
Organizational costs (e.g., corporate bylaws, other agreements)	Expense	Expense	Expense	Organizational costs should be expensed in accordance with ASC 720-15.
Overhead, including rent, depreciation, and support functions (executive management, accounting, purchasing, corporate legal, human resources, and information systems)	Expense	Expense	Generally expense	General and administrative and overhead costs should be charged to expense as incurred, with a limited exception for property constructed for sale or rental. See UP 12.2.2.
Outsourced administrative functions (e.g., accounting, purchases, and payables)	Expense	Expense	Generally expense	General and administrative and overhead costs should be charged to expense as incurred, even if the costs are incurred by a third party on behalf of the reporting entity. These costs may be eligible for capitalization if the property is constructed for sale or rental. See UP 12.2.2.
Project financing—external fees	Capitalize	Capitalize	Capitalize	Staff Accounting Bulletin (SAB) Topic 5.A, <i>Expenses of Offering</i> (SAB Topic 5.A) which was codified as ASC 340-10-S99-1, permits capitalization of specific incremental costs directly attributable to a debt financing. Any amortization recorded during construction would be included in capitalized interest calculations.

Type of cost	Phase			Considerations
	Preliminary	Pre-acquisition	Construction	
Project financing—internal costs and salaries	Expense	Expense	Expense	SAB Topic 5.A specifically precludes capitalization of internal costs of a debt financing.
Property taxes	Expense	Expense	Generally expense	Property taxes are a cost of owning the property and are not a direct incremental cost of construction; thus, such amounts should be expensed as incurred. However, similar to ground lease expense, such amounts may be capitalized if the property is being constructed for sale or rental. See UP 12.2.2.
Recruiting (costs to identify and hire operating and administrative personnel on site)	Expense	Expense	Expense	Recruiting costs should be expensed in accordance with ASC 720-15.
Salaries—developers, legal counsel, and other personnel working directly on the project	Expense	It depends	It depends	All payroll and payroll-related costs should be expensed until the project is probable. Once the project is probable, directly identifiable payroll and payroll expense should be capitalized. The amount capitalized should be limited to those amounts directly related to the site and project selected (e.g., costs related to evaluation of potential projects or locations should be expensed). In addition, occupancy and similar costs associated with personnel working on the project should be expensed.
Salaries—support functions	Expense	Expense	Generally expense	General and administrative costs should be expensed as incurred, with a limited exception related to property constructed for sale or rental. See discussion under “Overhead” costs.

Type of cost	Phase			Considerations
	Preliminary	Pre-acquisition	Construction	
Site permit and license fees	Expense	Capitalize	Capitalize	Site permit and related fees are a direct cost of construction and should be capitalized once construction is probable.
Site security costs	Expense	Capitalize	Capitalize	Site security costs are a direct cost of construction and should be capitalized once construction is probable. Amounts capitalized should be limited to incremental security costs.
Software development costs	Expense	Capitalize as permitted	Capitalize as permitted	Software development costs should be capitalized in accordance with the requirements of ASC 350-40.
Test power	Not applicable	Not applicable	Capitalize	Test power revenue and related incremental expense (e.g., fuel) should be capitalized as part of the cost of the asset under construction. See UP 12.2.1.3.
Training costs	Expense	Expense	Expense	Training costs should be expensed in accordance with ASC 720-15.
Travel expenses—internal and third party	Expense	It depends	It depends	See discussion under “Consulting fees.”
Turbine deposits	Capitalize	Capitalize	Capitalize	During the preliminary phase of a project, turbine deposits should be capitalized if the deposits could potentially benefit another internal or third-party project. The deposits should also be capitalized once the project is probable. Any amounts capitalized should be recorded at the lower of cost or market.

Chapter 13:
Asset retirement
obligations

13.1 Chapter overview

Utilities and power companies often have significant asset retirement obligations (AROs) due to their ownership of power plants and other major plant assets that ultimately will be removed from service. ASC 410, *Asset Retirement and Environmental Obligations*, contains the guidance for the recognition, measurement, and disclosure of asset retirement obligations in ASC 410-20.

This chapter addresses common issues in accounting for AROs by utilities and power companies. See ARM 4580 and FV 7.5.1 for further information on applying the guidance in ASC 410 more generally. In addition, ASC 410-20-55 includes examples of the application of the guidance that are useful for utilities and power companies.

13.2 Scope of the ARO guidance

The scope of the asset retirement obligation guidance includes the following types of transactions.

Excerpt from ASC 410-20-15-2

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

- a. Legal obligations associated with the retirement of a tangible long-lived asset that result from the acquisition, construction, or development and (or) the normal operation of a long-lived asset, including any legal obligations that require disposal of a replaced part that is a component of a tangible long-lived asset.
- b. An environmental remediation liability that results from the normal operation of a long-lived asset and that is associated with the retirement of that asset. . . .
- c. A conditional obligation to perform a retirement activity. Uncertainty about the timing of settlement of the asset retirement obligation does not remove that obligation from the scope of this Subtopic but will affect the measurement of a liability for that obligation. . . .
- d. Obligations of a lessor in connection with leased property that meet the provisions in (a). . . .

An asset retirement obligation is a legal obligation. It can be established by agreement between two or more parties, imposed by a government unit, or arise due to promissory estoppel (i.e., through third-party reliance on a promise, even in the absence of consideration in exchange for that promise). Considerable judgment, along with assistance from legal counsel, will be required to determine whether an obligation should be recorded due to promissory estoppel.

The following assets may have associated asset retirement obligations:

- Nuclear, natural gas, or hydro-electric plants that arise from holding related licenses (e.g., a license for nuclear facilities issued by the Nuclear Regulatory Commission)
- Natural gas pipelines or storage facilities
- Coal plants
- Asbestos around pipes or in a building wall that must be removed at the time the related asset is retired
- Transmission assets (including transformers and wires)
- Landfills or plugged and abandoned injection wells
- Water wells and wastewater treatment facilities

This list is not all-inclusive. Reporting entities should assess all tangible long-lived assets for potential asset retirement obligations.

13.2.1 *Asset retirement obligations related to component parts*

In addition to applying to the retirement of an entire asset, ASC 410-20-55-9 indicates that a reporting entity may have retirement obligations for component parts of a larger system that are required to be retired in advance of the larger system. If the recognition criteria are met, the reporting entity should record an asset retirement obligation associated with interim component retirements. Examples of these types of obligations include:

- *Utility poles*

A regulated utility may conclude that its distribution system has an indefinite life and thus would not record an asset retirement obligation for the system as a whole. However, when individual poles are retired, the reporting entity may be required to pay for environmentally-safe handling and disposal because of hazardous chemicals used to treat the poles.

- *Natural gas pipelines*

A pipeline or natural gas distribution system owner may conclude that it will not abandon a pipeline system in place but would replace segments of the pipe on a rotating basis. Although the overall pipeline is not abandoned, the owner would be required to cut, cap, and purge the old pipe if it were to construct a new pipe parallel to the old pipe in lieu of complete replacement.

In these examples, although no asset retirement obligation would be recorded for the entire system, the reporting entity should estimate and record the component asset retirement obligation related to the utility poles or pipeline, respectively.

The level of detail maintained in the plant records has no impact on the requirement to record AROs for component units. That is, a reporting entity should record a disposal obligation even if the individual assets are not identifiable in the plant records. See UP 12.2.3 for further information on asset componentization.

13.3 *Scope exclusions*

ASC 410-20 specifically excludes certain lease obligations, environmental remediation liabilities, and obligations arising solely from a plan to dispose of an asset.

13.3.1 *Lease obligations*

ASC 410-20 states that the requirement to record an asset retirement obligation does not apply to obligations of a lessee that are incorporated within minimum lease payments or contingent rentals as defined in ASC 840. However, although AROs included in minimum lease payments or contingent rentals are excluded from the scope of ASC 410-20, lease transactions are not otherwise exempt from the asset retirement obligation guidance.

In some cases, the lease itself may impose an asset retirement obligation on the lessee. For example, ground leases may include a requirement to return the property to “greenfield” status at the end of the lease. Such an obligation to remove leasehold improvements or perform remediation at the end of an operating lease should be evaluated under the ARO guidance.

The exclusion only applies to lessees. ASC 410-20 does apply to lessors of assets, if such lessors have an obligation associated with the retirement of tangible long-lived assets under lease.

13.3.2 *Environmental remediation liabilities*

The provisions of ASC 410-20 do not apply to obligations that result from improper operation of an asset, including environmental remediation liabilities, which are subject to ASC 410-30.

ASC 410-20-15-3(b) provides guidance to help distinguish between asset retirement obligations and obligations that should be accounted for as part of an environmental remediation reserve.

Excerpt from ASC 410-20-15-3

The guidance in this Subtopic does not apply to the following transactions and activities: . . .

- b. An environmental remediation liability that results from the improper operation of a long-lived asset (see Subtopic 410-30). Obligations resulting from improper operations do not represent costs that are an integral part of the tangible long-lived asset and therefore should not be accounted for as part of the cost basis of the asset. For example, a certain amount of spillage may be inherent in the normal operations of a fuel storage facility, but a catastrophic accident caused by noncompliance with an entity’s safety procedures is not. . . .

One factor that may be helpful in distinguishing AROs from environmental remediation liabilities or other contingencies is the timing of the required remediation efforts.

□ *Immediate remediation required*

Environmental damage extensive enough to require immediate remediation generally arises from improper operation of an asset (e.g., an oil spill or a pipeline leak). This type of environmental liability should be accounted for under ASC 410-30.

□ *Clean-up performed in connection with an asset's retirement*

The ability to delay remediation until asset retirement generally suggests that any damage arose from normal operations and was inherent in operating the asset. Environmental damage arising from normal operations is subject to ASC 410-20; therefore, the cost of such remediation is included in the ARO measurement.

The determination of whether an obligation should be accounted for in accordance with ASC 410-20 or other appropriate literature is a matter of judgment based on individual facts and circumstances. See ARM 4560 for more information on accounting for environmental costs under ASC 410-30.

13.3.2.1 Asbestos

Asbestos to be removed in conjunction with the retirement of an asset is an ARO subject to the requirements of ASC 410-20. A reporting entity should include the estimated cost of asbestos removal in the measurement of the asset retirement obligation. However, it should account for asbestos clean-up that must be performed before asset retirement in accordance with the guidance in ASC 410-30.

13.3.3 Obligations arising from plans to dispose of an asset

The ARO guidance does not apply to obligations that arise solely from a plan to dispose of a long-lived asset. For example, to obtain permission to sell a generating station to an out-of-state entity, a reporting entity may agree to transfer excess land to the local municipality and convert the land to a park. If the requirement to transfer and convert the land arises solely as a result of the decision to sell the plant, the reporting entity should not record an asset retirement obligation.

Notwithstanding this, if a reporting entity refines its estimate of an existing ARO as a result of procedures undertaken in connection with a potential sale, that obligation would be subject to the ARO guidance.

13.4 Recognition and measurement

Asset retirement obligations are initially recognized at fair value with a corresponding asset retirement cost (ARC) recorded as part of the related plant asset. Figure 13-1 highlights various accounting considerations over the life of the ARO.

Figure 13-1

Impact on the financial statements of recording asset retirement obligations

Phase	Balance sheet	Income statement	Statement of cash flows
At inception (cost initially recognized in accordance with ASC 410)	<ul style="list-style-type: none"> □ Record ARO at fair value of the legal obligation □ Record the ARC as an increase to the carrying value of the related asset 	<ul style="list-style-type: none"> □ No immediate impact 	<ul style="list-style-type: none"> □ No immediate impact
Passage of time	<ul style="list-style-type: none"> □ Increase ARO through periodic accretion expense □ Allocate ARC to expense using a systematic and rational method over asset's useful life 	<ul style="list-style-type: none"> □ Record accretion expense as a component of operating expense; should be in a separate caption if significant □ Record ARC depreciation 	<ul style="list-style-type: none"> □ Classify accretion and depreciation as noncash adjustments to net income within operating cash flows
Changes in expected cash flows	<ul style="list-style-type: none"> □ Adjust for change in the ARO □ Record corresponding change in the ARC 	<ul style="list-style-type: none"> □ No immediate impact □ Reflect change in accretion and depreciation in period of change (if applicable) and future periods 	<ul style="list-style-type: none"> □ No immediate impact □ Classify accretion and depreciation as noncash adjustments to operating cash flows
Retirement	<ul style="list-style-type: none"> □ Derecognize ARO as remediation occurs □ Derecognize any remaining unamortized ARC 	<ul style="list-style-type: none"> □ Record a gain or loss for the difference between the cost of settling the ARO and the recorded liability □ Derecognize remaining unamortized ARC with corresponding gain or loss 	<ul style="list-style-type: none"> □ Classify cash outflows for settlement of the ARO in operating cash flows □ Any settlement difference is a noncash adjustment to operating cash flows

13.4.1 *Initial recognition*

Asset retirement obligations are recognized at fair value in the period in which they are incurred, and when the amount of the liability can be reasonably estimated. Determining the appropriate timing of recognition may be complex if the ARO arises over a period of time or due to a change in laws.

Question 13-1

When should a reporting entity record an asset retirement obligation related to an asset under construction?

PwC response

Construction of utility and power-generation related assets (e.g., generating stations, transmission towers, pipelines) often extends beyond a single reporting period. Although construction may take time to complete (e.g., a nuclear generation facility can take 10 years to bring to commercial operation), the reporting entity will usually know prior to the start of construction whether it will have a related asset retirement obligation.

The method used to account for asset retirement obligations during construction should be based on the individual facts and circumstances. Two methods that may be appropriate are:

□ *Proportionate method*

The ARO is recorded proportionately as the underlying construction is completed. This method would be applied if the cost of the ARO is generally related to the cost of decommissioning the whole facility. For example, this method may be appropriate for an ARO related to an entire generating facility when the reporting entity is required to remove the facility at the end of a ground lease. In that case, the cost of removing the facility would be expected to be proportionate to the amount constructed (i.e., if 50 percent of the cost of the plant has been incurred, 50 percent of the ARO should be recorded).

□ *Specific method*

An ARO is recorded when the specific costs leading to the obligation are capitalized. For example, absent other obligations, if the cost of an ARO related to a nuclear power plant arises as a result of the fuel rods being installed, the ARO would be recorded only at that time. In that case, the start of construction would not trigger recording the ARO.

Reporting entities involved in asset construction should develop appropriate policies for the recognition of AROs during the construction phase. Although there are different approaches, we would generally expect the same method to be applied consistently to similar assets. Furthermore, while reporting entities should begin accreting an ARO as soon as it is recognized, depreciation of the ARC would not begin until the related asset, or component of the asset, is placed in service.

13.4.2 Measurement

Asset retirement obligations should be initially measured at fair value under the fair value guidance in ASC 820, *Fair value measurements*. ASC 410-20-30-1 provides further guidance on how the fair value of an ARO is usually measured.

Excerpt from ASC 410-20-30-1

An expected present value technique will usually be the only appropriate technique with which to estimate the fair value of a liability for an asset retirement obligation.

Applying the expected present value technique requires an entity to incorporate explicit assumptions about the amount and timing of costs under different future scenarios, and the relative probabilities of those scenarios. ASC 410-20-25-7 indicates that uncertainty in the timing of cash flows should be incorporated in the measurement through the assignment of probabilities to those cash flows. The key factors that impact the expected present value calculation include timing, amount, and the discount rate, as summarized in Figure 13-2.

Figure 13-2
Factors impacting the initial asset retirement obligation measurement

Concept	Key considerations
Timing	<ul style="list-style-type: none"> □ Assumptions and probabilities about when the ARO may settle should be incorporated into the measurement of the ARO. □ Uncertainty about the timing of settlement does not change the fact that an ARO exists; any uncertainty should be incorporated into the probability analysis. □ There may be differences between the expected settlement date and the asset’s useful life (e.g., due to license dates, lease periods, past history of retirement of similar units).
Amount	<ul style="list-style-type: none"> □ Fair value measurement under ASC 820 requires use of market participant assumptions. □ The cost of third-party resources should be used in the measurement even if the reporting entity plans to settle the ARO using internal resources. □ Probability analysis should include different assumptions, similar to timing of cash flows.
Discount rate	<ul style="list-style-type: none"> □ Cash flows should be discounted using a credit-adjusted risk-free rate. □ Funding and assurance arrangements should be considered in determining the appropriate rate.

13.4.2.1 *Timing*

One important factor in measuring an ARO is the length of time until its settlement. The asset's depreciable life provides one data point about the potential timing of the asset retirement. However, there may be a distinction between the physical life of the asset and the date the retirement obligation will be settled. Other factors should be considered in developing retirement scenarios for a power generation facility, including license expiration dates, the reporting entity's retirement history, management's plans for plant repowering, the length of a ground lease, if any, and the plant economics. ASC 410-20-25-11 provides indicators to consider in making the evaluation.

Excerpt from ASC 410-20-25-11

... The estimated economic life of the asset might indicate a potential settlement date for the asset retirement obligation. However, the original estimated economic life of the asset may not, in and of itself, establish that date because the entity may intend to make improvements to the asset that could extend the life of the asset or the entity could defer settlement of the obligation beyond the economic life of the asset. In those situations, the entity would look beyond the economic life of the asset in determining the settlement date or range of potential settlement dates to use when estimating the fair value of the asset retirement obligation.

Reporting entities should ensure that differences in depreciable lives, planned asset retirement dates, and lease and license expiration dates are supportable. In addition, the asset retirement cost capitalized as part of the asset will be depreciated over the depreciable life of the plant, not the period through the planned asset retirement date.

Question 13-2

Should an asset retirement obligation be recognized when the timing or method of settlement is conditional on a future event?

PwC response

It depends. Conditional asset retirement obligations are defined in ASC 410-20-20.

Definition from ASC 410-20-20

Conditional Asset Retirement Obligation: A legal obligation to perform an asset retirement activity in which the timing and (or) method of settlement are conditional on a future event that may or may not be within the control of the entity.

ASC 410-20-25-7 states that the obligation to perform an asset retirement activity is unconditional even though uncertainty exists about the timing or method of settlement. Therefore, even if the timing or method of settlement is uncertain and may be conditional on a future event, if an obligation exists, it should be measured and recorded if the fair value can be reasonably estimated. ASC 410-20-25-8 states

that a reporting entity would have sufficient information to apply an expected present value technique if either of the following conditions exists:

- The settlement date and method of settlement have been specified by others
- The information is available to reasonably estimate all of the following: (1) the settlement date or range of settlement dates; (2) the method, or potential methods, of settlement; and (3) the probabilities associated with the potential settlement dates and methods.

As further discussed in Question 13-4, in some cases, the settlement timing may be indeterminate; thus, no obligation would be recorded because the criteria would not be met. If, however, the reporting entity has an obligation to remove an asset, management should develop scenarios related to the potential timing of removal. If a range of possible settlement dates exists, then the period is not indeterminate and accrual of a liability would be required. This is consistent with the expected present value approach, which requires consideration of a variety of possible settlement dates.

Question 13-3

Should an asset retirement obligation be recognized when there is a legal obligation to perform but uncertainty exists as to whether the obligation will be enforced?

PwC response

Yes. When a reporting entity has a legal obligation to perform a retirement activity but uncertainty exists as to whether that obligation will be enforced, the uncertainty affects the measurement of the liability, but not its recognition. The underlying rationale is that the existence of the obligating event requires recognition of a liability, irrespective of when the event will occur.

Question 13-4

How is the recording of an asset retirement obligation affected if the asset has an indeterminate useful life?

PwC response

There may be instances when there is no available information regarding the ultimate timing of settlement of an ARO. As a result, consistent with the guidance in ASC 410-20-25-10, an ARO may not be reasonably estimable and no liability will be recorded until there is sufficient information to determine fair value.

In addition, if management has the intent and ability to operate an asset indefinitely, it may be appropriate to conclude that the asset has an indeterminate life (however, see UP 13.2.1 for a discussion of potential AROs associated with the retirement of component units). Before concluding that an asset has an indeterminate life, a reporting entity should consider, at a minimum:

- Regulatory and license requirements

- Results of historical operations, capital, and maintenance programs
- Engineering analysis
- Plans of joint owners, if applicable
- Cash flow and earnings forecasts
- Consideration of prior retirements of similar assets
- Lease terms, if a lease is involved

In assessing whether generating plants have indeterminate lives, reporting entities should also consider license requirements and public expectations.

In addition, the reporting entity is required to periodically reassess its obligations and should record the ARO at the time it becomes measurable.

Question 13-5

Should a reporting entity record an asset retirement obligation if it has no legal obligation to remove the asset?

PwC response

It depends. In some cases, a reporting entity may not be required to remove an asset which has a definite life, thus creating uncertainty about whether and when the reporting entity has an ARO that it will need to settle. Examples include a decommissioned plant that will be mothballed but not dismantled, or pipelines that are no longer in use that will be left in the ground. If there is no obligation to remove the asset (whether due to contract, law, or promissory estoppel), then the reporting entity is not required to record an asset retirement obligation. However, even if the reporting entity does not plan to dismantle or remove the asset, any costs of monitoring the asset after it has been retired from use should be considered in determining and recording an asset retirement obligation.

In addition, ASC 980-410-25-2 provides specific guidance when a regulated utility is collecting amounts in rates for retirement costs that do not meet the definition of an asset retirement obligation (i.e., cost of removal that is not a legal obligation). Such cost of removal included in depreciation expense should be recorded as a regulatory liability (see UP 18.8).

Application example – evaluating timing of settlement of the asset retirement obligation

Example 13-1 illustrates considerations in evaluating the timing of settlement of the asset retirement obligation.

EXAMPLE 13-1**Evaluating timing of settlement of an asset retirement obligation**

Rosemary Electric & Gas Company operates a nuclear generating plant which it operates under a license from the Nuclear Regulatory Commission. REG originally recorded an ARO based on the original license expiration date; however, management now intends to apply for a license renewal.

What should REG consider in evaluating the timing of settlement of the ARO?

Analysis

The timing of the cash flows in REG's expected present value analysis should include a scenario whereby the license is renewed and decommissioning of the plant is delayed. The weight assigned to this probability should consider all relevant facts and circumstances, including:

- Management's past success in obtaining similar licenses
- The political climate (e.g., is there a homeowners' or other group that will object to the relicensing?)
- Regulatory environment, including licensing requirements
- Plant economics — is it profitable to continue operating or are there prohibitive costs associated with repowering the plant?

The outcome of this assessment may also impact the depreciable life or expected salvage value of the plant. However, the life of the plant and the timing of the asset retirement may differ. Depreciation is an accounting allocation methodology based on management's current best estimate of the useful life and expected salvage value at the end of the life of the facility.

13.4.2.2 Estimates of future cash flows

As discussed in ASC 410-20-55-13, a reporting entity should incorporate explicit assumptions about the expected amount of future cash flows into the fair value analysis, including evaluation of the following amounts:

- The costs that a third party would incur to retire the asset
- Other factors that a third party would consider in determining the cost of the settlement, such as inflation, overhead, equipment charges, required profit margin, and advances in technology
- The price that a third party would demand and could expect to receive for assuming the risk related to uncertainties and unforeseeable circumstances inherent in the obligation (sometimes referred to as a "market risk premium")

Due to the nature of asset retirement obligations, reporting entities may not always have directly observable or comparable information about the assumptions that market participants would use in assessing the fair value of a liability. In those cases, the reporting entity may rely on information and assumptions based on its own expectations, provided there is no contrary data indicating that market participants would rely on different assumptions (e.g., if a reporting entity knows its labor costs are higher than market, the lower market rates should be used). In addition, the reporting entity should include a profit margin.

Question 13-6

Can the estimate of an asset retirement obligation be based on the reporting entity's own costs to settle the obligation?

PwC response

No. Although some reporting entities may have the expertise necessary to settle an ARO using internal resources and may intend to do so, ASC 820 requires the use of market participant assumptions in measuring the ARO's fair value, notwithstanding the reporting entity's specific plans for retiring the asset. Therefore, even though a reporting entity may believe assumptions about profit margin, overhead, and other costs that are based on third-party costs could result in a gain at the time the asset is retired, the fair value measurement should incorporate market participant assumptions. Excluding certain costs or assigning a low or zero probability to a third-party retirement scenario would be inconsistent with the requirements of ASC 410-20.

Question 13-7

Should salvage value be included as an offset to future cash flows in measuring the asset retirement obligation?

PwC response

No. Salvage value and other related cash inflows are included in determining the depreciable base of the asset. As a result, the estimated salvage value is excluded from the cash flows used to estimate the ARO.

13.4.2.3 Determination of the discount rate

In accordance with ASC 410-20-55-15, the expected present value technique requires that the estimated cash flows be discounted using a credit-adjusted risk-free rate. The risk-free rate is the interest rate on monetary assets that are essentially risk-free (e.g., in the United States, zero coupon U.S. Treasury instruments) and that have maturity dates that coincide with the expected timing of the estimated cash flows required to satisfy the ARO. Reporting entities should use the appropriate rate based on the timing of individual scenarios. That is, if there is an equal chance that retirement will occur in 2020 or 2030, the reporting entity should apply one rate to the 2020 retirement and another to the 2030 retirement, based on the estimated forward yield curves at the date the obligation is calculated.

ASC 410-20-55-17 also requires an adjustment to the risk-free rate to reflect the credit standing of the reporting entity. See FV 8 for guidance on considering the effect of a reporting entity's credit standing.

Question 13-8

Is measurement of an asset retirement obligation impacted by funding and assurance provisions?

PwC response

No. In accordance with ASC 410-20-35-9, a reporting entity may not reduce the reported amount of an ARO as a result of any assurance arrangement it may have provided, such as a surety bond, letter of credit, or trust fund. However, these arrangements should be considered in determining the credit-adjusted risk-free rate used to discount the cash flows associated with the liability. In determining the impact of funding or assurance arrangements, the reporting entity could look to, as an example, the impact that establishment of a nuclear decommissioning trust fund or a sinking fund arrangement would have on its credit adjustment to the risk-free rate. See FV Question 7-3 for further information.

13.4.2.4 Application example — expected present value technique

Example 13-2 illustrates the application of the expected present value technique to the dismantling of a nuclear power plant.

EXAMPLE 13-2

Applying the expected present value technique

Rosemary Electric & Gas Company owns a nuclear power plant that it plans to decommission in 2030 and is determining the initial fair value of its asset retirement obligation.

Which scenarios would REG consider in its expected present value calculation?

Analysis

Management determines that there are three potential scenarios for retirement of the asset (amounts in millions):

	Probability	Timing	Estimated third-party cost	Credit adjusted risk-free rate	Present value	Probability-weighted present value
Dismantle in 2030; use U.S. Department of Energy (DOE) disposal facilities	65%	2030; one-time cost	\$ 1,775	10%	\$ 161	\$ 105
Entomb plant in 2030; ongoing monitoring for 50 years	30%	2030; Annual	1,500 10	10% 10% ⁽¹⁾	137	41
Dismantle in 2030; DOE facilities are not available, third party paid to assume disposal liability	5%	2030; one-time cost	5,000	10%	455	23
Expected value						\$ 169

Costs are not discounted.

¹ As these costs are incurred each year, they should be discounted based on the applicable rate for each year; however, for simplicity the same rate is used for all cash flows.

13.4.3 Subsequent measurement

ASC 410-20-35-3 states that subsequent to initial measurement, a reporting entity should recognize changes in the ARO that result from (a) the passage of time and (b) revisions made to the timing or amount of future cash flows. A change that is due to the passage of time should be incorporated into the liability prior to any revisions that are made to the ARO as a result of changes in the timing or amount of estimated cash flows.

13.4.3.1 Changes due to passage of time

A reporting entity should determine the change in the liability resulting from the passage of time by applying the interest method. In applying this method, the reporting entity should use the credit-adjusted risk-free rate(s) applied when the liability (or a portion thereof) was initially measured.

Changes resulting from the passage of time should be recognized as an increase in the carrying amount of the liability, with a corresponding period cost classified in the operating section of the income statement. The reporting entity should separately disclose the amount if it is material. ASC 410-20-45-1 allows the use of any descriptor for this item “so long as it conveys the underlying nature of the expense.” In accordance with ASC 835-20-15-7, accretion expense cannot be included in interest costs for purpose of capitalization.

13.4.3.2 Revisions to the amount of cash flows

Changes in the obligation amount as a result of use of the asset, changes in available technology, or other factors should be recognized in the period of change as an increase or decrease in (1) the carrying amount of the ARO and (2) the ARC. The adjustment will not have any income statement impact in the period of change; however, it will impact the future recognition of amortization and accretion expense. The discount rate used to calculate the new ARO and ARC for changes in the

estimated cash flows will depend on whether there is an upward or downward revision in estimated cash flows, as discussed in ASC 410-20-35-8.

Excerpt from ASC 410-20-35-8

... Upward revisions in the amount of undiscounted estimated cash flows shall be discounted using the current credit-adjusted risk-free rate. Downward revisions in the amount of undiscounted estimated cash flows shall be discounted using the credit-adjusted risk-free rate that existed when the original liability was recognized. If an entity cannot identify the prior period to which the downward revision relates, it may use a weighted-average credit-adjusted risk-free rate to discount the downward revision to estimated future cash flows. ...

13.4.3.3 Revisions to the timing of cash flows

Under the expected present value approach, the discount rate for each scenario will depend on the expected timing of the cash outflows. That is, if a reporting entity has scenarios under which the retirement could occur in 2020, 2030, and 2040, each scenario would be discounted at a different credit-adjusted risk-free rate based on the forward yield curves at the date the obligation is calculated. Therefore, if the timing of the expected cash flows changes, the reporting entity should use the current credit-adjusted risk-free rate for the new scenarios.

Question 13-9

What is the impact of a downward revision of an asset retirement obligation that exceeds the carrying value of the related asset retirement cost?

PwC response

Subsequent to establishing an ARO, if a reporting entity experiences a downward revision in the liability due to a change in the expected timing or amount of cash flows, it should correspondingly decrease the asset retirement cost. Due to the differences in the pattern of accretion of the ARO and the amortization of the ARC, the reporting entity may experience a decrease in the carrying amount of the ARO that exceeds the undepreciated ARC. In such cases, for regulated entities, we generally believe that the ARO should be reduced to reflect the change and the remaining undepreciated ARC should be derecognized with a gain recognized in the income statement for any difference. However, for entities that are not regulated, the reporting entity should consider whether the ARC and related plant assets are viewed as a single unit of account (in which case it may be appropriate for the remaining net credit to reduce the carrying value of the related plant assets).

Question 13-10 addresses accounting for AROs when the composite method of depreciation is used.

Question 13-10

Where should a reporting entity record any gain or loss on settlement of an asset retirement obligation when the composite or group method of depreciation is used?

PwC response

Utilities and power companies often use the group or composite method of depreciation in accounting for their plant assets (see UP 12.3.1). Under that approach, any gain or loss arising upon the retirement of plant assets is recorded as an adjustment to accumulated depreciation for the related asset group (i.e., no gain or loss is recognized in the income statement). However, as noted in Figure 13-1, any difference in the ultimate settlement of the ARO and its recorded amount is generally recorded as a gain or loss in the income statement. As a result, if a reporting entity is applying the composite method of depreciation, a question arises as to whether the ARO gain or loss should be recorded in the income statement or as an adjustment to accumulated depreciation along with the related asset (including the ARC).

We believe the accounting for AROs is an inherent part of a reporting entity's fixed asset accounting policies. Therefore, if a reporting entity has elected to use the group or composite method of depreciation, it should apply the same approach to its accounting for AROs. Applying the group or composite approach for AROs may include the following conventions:

- The accounting for actual costs incurred to settle the ARO, if different than the ARO balance at the time of settlement, as a charge to accumulated depreciation.
- Recording accretion expense for the ARO during a current year based on the previous year's balance, on a group basis.
- Regular revisions of the estimated ARO consistent among a related group of assets. Such a revision should be performed similar to an updated depreciation study, taking into account changes in the ARO in the current period.

Any adjustment required as a result of the analyses would result in a charge to accumulated depreciation consistent with the approach for group or composite depreciation. Such adjustments to accumulated depreciation will be reflected in future depreciation expense based on the reporting entity's updated depreciation studies.

When a reporting entity applies the group or composite method of depreciation, individual assets and their related AROs are not separately accounted for or tracked in the accounting systems. Rather, depreciation, normal retirements, and AROs are accounted for on a pooled basis and no discrete gains and losses are recognized. Therefore, we believe that it is appropriate to record settlement gains or losses to accumulated depreciation instead of the income statement. However, as discussed in Question 12-8, a gain or loss (including amounts related to changes in the ARO) should be recognized in earnings when abnormal retirements have occurred.

If AROs are established on a unitary basis and actual retirement costs incurred can be matched to an individual asset and ARO, or the reporting entity follows a unitary

approach to accounting for depreciation, it should record gains and losses in the income statement. Similarly, AROs for discrete assets (such as a complete power plant) would follow a unitary approach. Such amounts should be presented as noncash adjustments to net income within operating cash flows in the statement of cash flows.

Chapter 14:
Nuclear power plants

14.1 Chapter overview

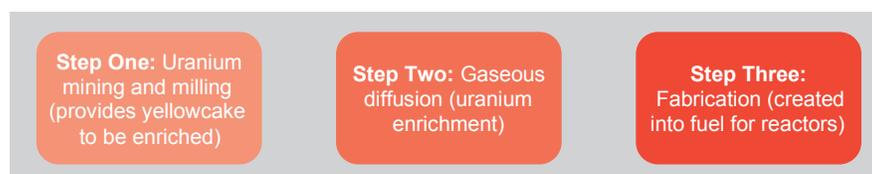
Many utilities and power companies own nuclear power plants as part of their generation fleets. Ownership of such plants creates certain unique accounting issues. Nuclear generating plants operate under the jurisdiction of the Nuclear Regulatory Commission (NRC). The NRC has responsibility for regulating nuclear power reactors, prescribing and monitoring safeguards over nuclear material, and licensing the construction and operation of nuclear plants. This regulatory oversight results in specific accounting considerations, such as accounting for spent nuclear fuel, plant decommissioning, and related investments. In addition, accounting for the procurement of nuclear fuel, and the fuel itself, is different from accounting for other types of fuels used for generation, such as natural gas.

This chapter addresses accounting issues for owners and operators of nuclear power plants. See UP 12 for information on general plant issues, UP 13 for information on accounting for asset retirement obligations, and UP 15 for information on joint plant accounting.

14.2 Accounting for uranium contracts

The creation of nuclear fuel involves three key steps. Figure 14-1 depicts these steps at a high level.

Figure 14-1
Creation of nuclear fuel



Reporting entities that own nuclear generating units typically obtain much of their uranium through long-term contracts with suppliers. The accounting considerations for contracts for uranium are similar to those for power, natural gas, or other commodities.

A reporting entity that enters into a contract for the purchase of uranium should apply the commodity contract accounting framework to determine the appropriate accounting (see UP 1). Under the framework, after identifying the deliverables and the unit of accounting, a reporting entity should first determine whether the uranium agreement contains a lease. If lease accounting does not apply, a reporting entity should next assess whether it is a derivative in its entirety. If neither lease nor derivative accounting apply, the reporting entity should account for the agreement as an executory contract (i.e., on an accrual basis) and consider whether it contains any embedded derivatives requiring separation from the host contract. The accounting model applied significantly impacts initial and subsequent recognition and measurement.

14.2.1 *Lease accounting*

ASC 840 provides guidance for determining whether an agreement that transfers the right to use identified property, plant, and equipment should be accounted for as a lease. In accordance with this guidance, an arrangement contains a lease if (1) fulfillment of the arrangement is dependent on the use of identified property, plant, or equipment, and (2) the arrangement conveys the right to control use of the property, plant, or equipment.

Although contracts for nuclear fuel can be the subject of a lease, in general, we would not expect a contract for uranium to be a lease.

14.2.2 *Derivative accounting*

Assuming a contract for the delivery of uranium does not contain a lease, the reporting entity should evaluate whether it is a derivative in its entirety in accordance with ASC 815-10-15-83, which is addressed in UP 3. Figure 14-2 highlights the derivative evaluation for a typical uranium contract.

Figure 14-2

Does a contract for the delivery of uranium meet the definition of a derivative?

Criterion in ASC 815	Evaluation	Comments
Notional amount and underlying	Met	<ul style="list-style-type: none"> □ Notional (quantity of uranium) and underlying (the price) are usually specified.
No initial net investment	Met	<ul style="list-style-type: none"> □ No initial net investment is typically required.
Net settlement	It depends	<ul style="list-style-type: none"> □ Uranium contracts are generally physically settled; implicit net settlement is not typical but should be evaluated. □ The reporting entity should evaluate whether the contract meets the readily-convertible-to-cash criterion, considering factors such as the type of uranium, transportation costs, and contract volume.

As noted in Figure 14-2, the net settlement criterion is the one that requires the most judgment. A forward contract for physical delivery of uranium may meet the definition of a derivative if it meets the condition of net settlement.

ASC 815-10-15-83(c)

Net settlement. The contract can be settled net by any of the following means:

1. Its terms implicitly or explicitly require or permit net settlement.
2. It can readily be settled net by a means outside the contract.
3. It provides for delivery of an asset that puts the recipient in a position not substantially different from net settlement.

The following are considerations in assessing whether a forward contract for physical delivery of uranium has the characteristic of net settlement. See UP 3.2.3 for further information on the overall application of the net settlement criterion.

Net settlement under contract terms

When evaluating whether the net settlement criterion is met, a reporting entity should first consider whether the contract terms explicitly or implicitly provide for net settlement of the entire contract. Forward contracts for physical delivery of uranium typically require physical delivery and do not permit explicit net settlement. However, the reporting entity should review the contract's terms to ensure that there are no implicit net settlement terms or liquidating damage provisions that may imply that the contract could be net settled.

Net settlement through a market mechanism

In this form of net settlement, one of the parties is required to deliver an asset, but there is an established market mechanism that facilitates net settlement outside the contract. ASC 815-10-15-110 through 15-116 provide indicators to consider in assessing whether an established market mechanism exists. A key aspect of a market mechanism is that one of the parties to the agreement can be fully relieved of its rights and obligations under the contract.

We are not aware of any markets for net settlement of forward contracts for the physical delivery of uranium in the United States in which a provider has the ability to be relieved of its full rights and obligations under a previously-executed contract. Although there is a NYMEX futures contract for U308, which is not the subject of the contract, its existence does not provide a market mechanism for a physical bilateral contract not traded on the exchange.

Net settlement by delivery of an asset that is readily convertible to cash

Whether there is an active spot market for the particular product being sold under the contract is the key factor in assessing whether an asset is readily convertible to cash. Reporting entities should always consider current market conditions in this analysis. To be deemed an active spot market, a market should have transactions with sufficient frequency and volume to provide pricing information that is readily available on an ongoing basis (i.e., quoted prices are readily available). See UP 3.2.3.3 for further

information on the determination of whether a market is active. At the time of release of this guide, we understand that there are quoted prices for the physical purchase of certain types of uranium at limited locations; however, transaction volume is thin.

In addition to the activity in the market, reporting entities should also consider the following factors in evaluating whether the uranium in specific contracts is readily convertible to cash:

□ *Transportation costs*

ASC 815-10-15-125 through 15-127 allow a reporting entity to consider conversion costs in determining whether assets are readily convertible to cash. Therefore, in evaluating a uranium contract, a reporting entity may need to consider potential transportation costs, depending on the location of purchase. If the estimated transportation costs are 10 percent or more of the gross sale proceeds (based on the spot price at the inception of the contract), the costs are considered significant, and the asset would not meet the definition of readily convertible to cash.

□ *Transaction volume*

In assessing whether an asset is readily convertible to cash, a reporting entity should separately assess the expected quantity in each contract. Therefore, if a reporting entity is purchasing 50,000 tons daily in five separate 10,000-ton contracts, it should separately consider each of the contracts in relation to the daily market transaction volume. ASC 815-10-55-100 states that a reporting entity is required to consider each separate increment available.

Excerpt from ASC 815-10-55-10

. . . contracts shall be evaluated on an individual basis, not on an aggregate-holdings basis.

□ *Contract duration*

As noted, there are currently limited spot transactions for the physical purchase of uranium and limited quoted forward prices. Therefore, if a reporting entity concludes that there is an active spot market that is sufficient to absorb the daily contract quantity, it should further consider the duration of the contract, which may span multiple years.

ASC 815-10-55-116 clarifies when an asset would meet the definition of readily convertible to cash.

Excerpt from ASC 815-10-55-116

[if] an active spot market for the commodity exists today and is expected to be in existence in the future for each delivery date ... under the multiple delivery supply contract.

□ *Type of uranium*

The reporting entity should also assess whether the type and quality of the uranium is consistent with the type and quality transacted in the spot market.

Overall conclusion

Based on these factors and our current understanding of the uranium markets, we believe that forward contracts for the physical delivery of uranium are not readily convertible to cash. Thus, we believe that derivative accounting is generally not applicable to these contracts. However, a reporting entity should evaluate all facts and circumstances in concluding on the appropriate accounting for a specific nuclear fuel contract. In addition, a reporting entity should monitor its conclusion periodically as markets may evolve, potentially rendering this type of contract a derivative. Finally, if the contract is an executory contract, the reporting entity should evaluate it to determine if there are any embedded derivatives that require separation.

14.2.2.1 ***Conditionally designating contracts as normal purchases and normal sales***

A reporting entity may also consider conditionally designating nuclear fuel contracts under the normal purchases and normal sales scope exception if physical delivery is probable throughout the life of the contract and the other criteria for application of this exception are met (ASC 815-10-15-22 through 15-51, as applicable). If a conditionally-designated normal purchases and normal sales contract meets the definition of a derivative at a later date, it would be accounted for as normal from the time it becomes a derivative.

Absent such a designation, the reporting entity would be required to record the contract as a derivative, at its fair value, at the time it becomes a derivative. See UP 3.3.1 for further information on the normal purchases and normal sales scope exception.

14.2.3 ***Executory contract accounting***

If derivative and lease accounting are not applicable, a forward contract for the physical delivery of uranium should be accounted for as an executory contract. In such cases, reporting entities should evaluate whether there are any embedded derivatives that require separation from the host contract (see UP 3.4 for information on evaluating embedded derivatives).

In accounting for an executory contract for the forward purchase of uranium, the cost of uranium purchases should be capitalized as nuclear fuel in progress when title passes (generally when the uranium is received).

14.3 ***Accounting for nuclear fuel***

The nuclear fuel cycle covers the period of mining the uranium, converting it into fuel, using it to produce electricity, and disposing of the fuel. The disposal process refers to “spent” or used nuclear fuel. Accounting issues associated with the initial and

subsequent accounting for nuclear fuel, including spent nuclear fuel, are discussed in this section.

14.3.1 Initial accounting for nuclear fuel

Unlike other fuels, such as natural gas or coal, nuclear fuel is accounted for as plant, instead of inventory, because it is a long-lived tangible asset.

ASC 360-10-05-3

Property, plant, and equipment typically consist of long-lived tangible assets used to create and distribute an entity's products and services and include:

- a. Land and land improvements
- b. Buildings
- c. Machinery and equipment
- d. Furniture and fixtures.

In addition, nuclear fuel installed in the fuel rods is depreciable. The construction costs associated with fabricating and installing the fuel are generally accounted for like other construction work in progress (see UP 12.2 for information on costs to be included in construction of a plant). As a result, capitalized interest (or allowance for funds used during construction by regulated utilities) may be accrued.

- For the initial core load (initial construction of the plant), capitalized interest can accrue up to the commercial date of the reactor (see UP 12.2.1.3).
- For subsequent reloads of nuclear fuel, capitalized interest can accrue until all nuclear fuel assemblies have been received from fabrication.

14.3.2 Subsequent accounting for nuclear fuel

Once the nuclear fuel has been fabricated, assembled, and is ready for use, the reporting entity should consider subsequent accounting. The cost of nuclear fuel in the reactor is typically amortized based on a unit-of-production method. The amortization rate is developed based on the total cost of fuel in the reactor and the estimated energy to be produced from the fuel.

The same approach is applied whether the reporting entity has purchased the nuclear fuel or is leasing it (see Question 2-2 for information about a lease of nuclear fuel). In the case of leased fuel, the entire rental expense is generally included in fuel costs.

14.3.3 Spent nuclear fuel

After the nuclear fuel is fully utilized to produce power, it is termed "spent nuclear fuel." Spent nuclear fuel is highly radioactive because of the fission product content. It must be allowed to cool and decrease in radioactivity for several months. Such activity

is performed in a spent-fuel pool. After this cooling down period, the spent nuclear fuel requires long-term storage or disposal.

The U.S. Department of Energy (DOE) has responsibility for the permanent disposal of spent nuclear fuel and processed high-level radioactive waste. Under the Nuclear Waste Policy Act of 1982, entities that produce nuclear energy were required to pay \$0.001 per kilowatt-hour of net nuclear generation to the DOE for the cost of spent nuclear fuel disposal, which is generally accrued as nuclear power is generated. However, the DOE has not yet been able to develop an approved site for the permanent storage of spent nuclear fuel and high-level radioactive waste, even though it was legally required to start taking possession of spent nuclear fuel by January 31, 1998. As a result, at the time of this publication, there is an indefinite suspension of the payment until there is an approved solution for storage.

Spent-fuel pools have limited capacity and were not designed for the storage of all spent nuclear fuel and high-level radioactive waste generated during a nuclear unit's life. As a result of the DOE's delay in assuming possession of spent nuclear fuel and high-level radioactive waste, nuclear operators have had to find alternative means for the long-term storage of the spent nuclear fuel and high-level radioactive waste generated by a nuclear site. Some interim alternatives for storage of spent fuel include re-racking the spent-fuel pool, consolidating fuel rods, and using dry-cask storage. Dry-cask storage is a method of storing spent fuel that has already cooled in the spent-fuel pool for at least one year by surrounding it with inert gas inside a container called a cask.

Costs associated with interim storage solutions, such as dry cask, should be capitalized and accrued as the fuel is used. In addition, reporting entities should provide appropriate disclosures in the financial statements about significant estimates, commitments, and contingencies regarding spent fuel storage requirements.

Because of the DOE's failure to develop an approved site for the permanent storage of spent nuclear fuel and high-level radioactive waste, many companies have reached settlements with the DOE whereby the DOE agreed to reimburse certain costs related to spent nuclear fuel. In some cases, the government also agreed to a process for the reimbursement of subsequent annual claims.

In general, we would expect the amounts received in such settlements to reduce the carrying value of dry cask storage facility assets, similar to the accounting for contributions in aid of construction. See Question 12-2 for information on accounting for contributions received from others.

14.4 Nuclear decommissioning

Nuclear decommissioning requirements typically represent one of the most significant asset retirement obligations for nuclear licensees. The Nuclear Regulatory Commission (NRC) is responsible for overseeing the decommissioning of all nuclear power plants in the United States. The NRC has explicit requirements related to decommissioning nuclear power plants, including cleanup of contaminated plant systems and structures and removal of radioactive fuel. The NRC also specifies one of

three methods that must be used for the decommissioning process and requires decommissioning to be completed within 60 years of a facility's shutdown. Accounting for these asset retirement obligations is discussed in UP 13.

14.5 Nuclear decommissioning trust funds

NRC regulations require nuclear power plant licensees to demonstrate that the appropriate level of funds will be available for the decommissioning process. Nuclear decommissioning trust funds are commonly used by nuclear plant licensees to meet decommissioning funding requirements. Figure 14-3 provides a high-level summary of some of the NRC's requirements. In addition to those in Figure 14-3, the NRC has many other requirements related to nuclear decommissioning trust funds, including required funding levels. Title 10 of the Code of Federal Regulations, Part 50.75 provides more information.

Figure 14-3

Nuclear regulatory commission decommissioning requirements¹

Factor	Considerations
Financial assurance requirements	<p>Nuclear plant licensees must demonstrate financial assurance for decommissioning through one or more of the following methods:</p> <ul style="list-style-type: none"> <li data-bbox="748 1003 1422 1062">□ Prepayment — a deposit by the licensee at the start of operations <li data-bbox="748 1079 1357 1106">□ Surety, insurance, or parent company guarantee <li data-bbox="748 1123 1430 1213">□ External sinking fund (nuclear decommissioning trust fund) — a separate account managed by a party other than the licensee
Reporting requirements	<p>Licensees must report the status of decommissioning funds to the NRC at least once every two years and then annually when the plant is within five years of the planned shutdown and once operations cease. Required information includes:</p> <ul style="list-style-type: none"> <li data-bbox="748 1381 1390 1440">□ Amount of decommissioning funds estimated to be needed <li data-bbox="748 1457 1438 1516">□ Amount accumulated as of the end of the calendar year preceding the report <li data-bbox="748 1533 1430 1560">□ Schedule of annual amounts remaining to be collected <li data-bbox="748 1577 1373 1667">□ Assumptions used regarding rates of escalation in decommissioning costs and earnings on decommissioning funds <li data-bbox="748 1684 1446 1711">□ Changes in the method of providing financial assurance

Factor	Considerations
Additional considerations for nuclear decommissioning trust funds	<p>Use of decommissioning trust funds for assurance is available only to licensees that recover the cost of decommissioning through regulated rates or a non-bypassable surcharge. Additional considerations include:</p> <ul style="list-style-type: none"> □ As applicable, the NRC defers to state regulators or the Federal Energy Regulatory Commission to set standards for allowable types of investments. □ The NRC requires that a third-party, independent investment manager have administrative control over the trust funds with discretion to buy, sell, and invest to achieve the broad investment objectives stipulated by the trust fund owner. □ The investments should be “investment grade;” investments in a reporting entity’s own stock and other nuclear licensees are not permitted.

¹ Source: NRC website as of August 2015.

This section discusses accounting issues associated with investments held in nuclear decommissioning trust funds.

14.5.1 Initial and subsequent accounting

Nuclear decommissioning trust fund investments are within the scope of ASC 320 which addresses the accounting and reporting for investments in equity securities that have a readily determinable fair value and all debt securities. Accordingly, as required by ASC 320, nuclear decommissioning trust fund investments should be designated as trading, held-for-sale, or held-to-maturity, as applicable.

□ *Trading securities*

Gains and losses on trading securities (whether realized or unrealized) are recognized each reporting period in earnings.

□ *Available-for-sale securities*

Unrealized gains and losses on available-for-sale securities should be recognized in accumulated other comprehensive income, unless an investment is other-than-temporarily impaired, in which case all, or a portion of, losses are recorded in the income statement immediately. Realized gains and losses are recognized in income as they occur.

□ *Held-to-maturity securities*

Held-to-maturity securities are carried at amortized cost, unless an investment is other than temporarily impaired, in which case any losses recorded in the income statement are recorded to adjust the carrying amount of the investment to its fair value at the current measurement date.

In addition, a regulated utility may be able to support establishing a regulatory asset or liability to offset changes in fair value (see UP 17.3.1, including Question 17-3).

See ARM 5010 for further information on classification and measurement of debt and equity securities.

Note about ongoing standard setting

As of the content cutoff date of this guide, the FASB had projects on its agenda pertaining to the classification and measurement and impairment of financial assets. For public companies, the planned effective date for classification and measurement is 2018 and impairment is 2019. When issued, the new guidance should be considered for financial assets held after these effective dates.

Question 14-1

Are nuclear decommissioning trust fund investments eligible for the fair value option under ASC 825, *Financial Instruments*?

PwC response

Yes. ASC 825-10-15-4(a) indicates that a recognized financial asset or financial liability is eligible for the fair value option. Equity and debt investments are financial assets and thus meet this criterion.

Items for which a reporting entity is precluded from applying the fair value option by ASC 825-10-15-5 include investments in consolidated entities, investments held in pension and other postretirement plans, amounts accounted for as leases, and financial instruments classified by the issuer as part of equity. These exceptions would not impact investments in nuclear decommissioning trust funds.

Thus, investments held in nuclear decommissioning trust funds are eligible for the fair value option either on an individual security basis or as a portfolio (provided there is sufficiently clear documentation of such election).

Reporting entities that elect the fair value option for nuclear decommissioning trust fund investments are required to make the election at the time the investments are purchased; the election is irrevocable.

Under the fair value option, amounts are recognized on the balance sheet at fair value and gains and losses are recognized each reporting period in earnings, consistent with investments designated as trading. See FV 5 for further information on application of the fair value option.

14.5.2 Impairment

One of the key issues in accounting for investments in nuclear decommissioning trust funds is the recognition of impairment losses. The applicable accounting model depends on the type of security and the accounting designation as are summarized in

Figure 14-4. (As noted in UP 14.5.1, as of the content cutoff date of this guide, the FASB had ongoing standard setting related to impairment of financial assets.)

Figure 14-4
Accounting for nuclear decommissioning trust fund investments

Accounting consideration	Equity security: available-for-sale	Debt security: available-for-sale	Equity or debt security—fair value option or trading
Measurement basis	<ul style="list-style-type: none"> □ Measured at fair value with changes in fair value recorded in other comprehensive income 	<ul style="list-style-type: none"> □ Measured at fair value with changes in fair value recorded in other comprehensive income 	<ul style="list-style-type: none"> □ Measured at fair value with changes in fair value recorded in income
Impairment assessment	<ul style="list-style-type: none"> □ Other-than-temporary impairment assessment triggered if fair value declines below cost □ Immediate write down required if funds managed by a third party (see UP 14.5.2.1) 	<ul style="list-style-type: none"> □ Assessment required if fair value declines below cost □ Consider intent to sell and whether it is more likely than not will have to sell □ Involvement of third-party manager does not necessarily result in immediate write down 	<ul style="list-style-type: none"> □ Not applicable because gains and losses are recognized immediately

When reporting entities classify their investments as held-to-maturity debt securities, the impairment model is similar to that for available-for-sale, except that held-to-maturity securities are carried at amortized cost rather than at fair value. Under ASC 320-10-35-21, an available-for-sale or held-to-maturity debt security is considered to be impaired if its fair value is less than its amortized cost basis. Considerations in applying the impairment models follow.

14.5.2.1 Equity securities

In assessing whether a loss on an equity security is other-than-temporary, a public reporting entity should evaluate whether it has the ability and intent to hold it until recovery.

Excerpt from ASC 320-10-S99-1¹

The staff believes that the following are only a few examples of the factors which, individually or in combination, indicate that a decline in value of an equity security classified as available-for-sale is other than temporary and that a write-down of the carrying value is required:

- a. The length of the time and the extent to which the market value has been less than cost
- b. The financial condition and near-term prospects of the issuer ...; or
- c. The intent and ability of the holder to retain its investment in the issuer for a period of time sufficient to allow for any anticipated recovery in market value.

¹ The guidance codified in ASC 320-10-S99-1 was issued as SAB Topic 5.M, *Other Than Temporary Impairment of Certain Investments in Equity Securities*.

As the excerpt indicates, with regard to debt and equity securities held in nuclear decommissioning trust funds, the SEC staff believes that the inability to hold a security until recovery is a determining factor in concluding that a security is other-than-temporarily impaired. If a public reporting entity does not have the ability to hold to recovery, it cannot overcome the presumption of other-than-temporary impairment, regardless of any of the other criteria in ASC 320-10-S99-1.

We believe a public reporting entity's inability to control the disposition of the securities would preclude the assertion that it has the intent and ability to hold the security until recovery. Therefore, if there is a decline in value below the security's cost, a public reporting entity should treat impairments of an available-for-sale equity security as other-than-temporary and record a loss in the income statement immediately at the time the decline occurs. While this guidance is applicable to public entities, we believe that these indicators should be considered in the impairment analysis for non-public reporting entities as well.

14.5.2.2 Debt securities

ASC 320-10-35-18 includes specific criteria for determining if an impairment of debt securities is other-than-temporary. In accordance with ASC 320-10-35-18, if a debt security's fair value declines below cost, additional analysis is required to determine whether the impairment is considered other-than-temporary. Impairment for debt securities is considered to be other-than-temporary if any of the following conditions are present:

- The reporting entity intends to sell the security
- It is more likely than not the reporting entity will be required to sell the security before recovering its amortized cost basis

- The reporting entity does not expect to recover the security's entire amortized cost basis (even if it does not intend to sell), which may have resulted from the existence of credit losses or other factors

The guidance does not include a requirement to assert an ability and intent to hold the security. Therefore, unlike equity securities, the fact that debt securities held in a nuclear decommissioning trust fund are managed by a third-party investment manager would not impact the conclusion as to whether impairment is other-than-temporary. In such cases, we believe a reporting entity may take one of two views in determining whether it has an other-than-temporary impairment, as discussed in Question 14-2.

Question 14-2

How can a reporting entity assert it is not more likely than not that it will sell a debt security in a nuclear decommissioning trust fund managed by a third party?

PwC response

We believe a reporting entity may be able to make such an assertion by obtaining evidence regarding the intent of the third-party investment manager. Although management may not be able to prevent a third-party investment manager from selling an impaired debt security, were such a sale to occur, it would not necessarily be the same as a "required sale," as contemplated by ASC 320-10-35-33B.

ASC 320-10-35-33B

If an entity does not intend to sell the debt security, the entity shall consider available evidence to assess whether it more likely than not will be required to sell the security before the recovery of its amortized cost basis (for example, whether its cash or working capital requirements or contractual or regulatory obligations indicate that the security will be required to be sold before a forecasted recovery occurs). If the entity more likely than not will be required to sell the security before recovery of its amortized cost basis, an other-than-temporary impairment shall be considered to have occurred.

We believe only sales that involve a level of legal, regulatory, or operational compulsion should be considered "required" sales. If the assets managed by the third-party investment manager are not needed to fund current operating needs or to satisfy other legal or regulatory requirements, the fact that the reporting entity may not be able to prevent the manager from selling the debt security would not prevent the reporting entity from asserting that it is not more likely than not that it would be *required* to sell these securities. In addition, the fact that a third-party investment manager *may* sell a debt security does not necessarily mean that the sale is more likely than not.

This view is premised on the concept that because of the change in the indicators of other-than-temporary impairment, application of the impairment guidance in ASC

320-10-35 should result in consistent treatment for managed assets, whether managed internally or by a third-party investment manager.

A third-party investment manager typically acts as an agent for the reporting entity and performs a function that the reporting entity itself could legally perform. Although the contractual arrangement between the reporting entity and the asset manager may provide the asset manager with discretion regarding which assets to buy and sell, this discretion is typically defined within the parameters of a given investment strategy that is approved by the reporting entity. Effectively, the operation of the third-party asset manager is not dissimilar to the operation of the reporting entity's internal asset managers who must comply with internal investment guidelines.

However, we believe it would also be acceptable to consider all sales by the third-party investment manager to be "required," because, by contract, the reporting entity must sell the debt security once a manager has decided to do so. This assumes that a reporting entity's inability to prevent the asset manager from selling an impaired debt security also prevents it from asserting that it is more likely than not that these sales will not occur. Therefore, under this view, the lack of ability contemplated under previous other-than-temporary guidance would continue to result in other-than-temporary impairment for impaired securities managed by a third-party investment manager.

We believe that either view relating to debt securities is acceptable. The view adopted is an accounting policy election that should be applied consistently to all similar investments. If a third-party investment manager manages both debt and equity securities, this may result in the application of different impairment models for different types of securities managed by the same investment manager.

Chapter 15:
Joint plant and similar
arrangements

15.1 Chapter overview

Many utilities and power companies have joint plant interests in electric generating or other facilities. Joint plant refers to arrangements whereby two or more entities jointly operate underlying plant assets in which each party owns an undivided interest, without establishing a separate legal entity. Each party to the arrangement is responsible for financing its proportionate share of the cost of the plant and the cost of operations, and is entitled to its proportionate share of the output from the plant.

In other cases, a reporting entity may be involved in a power plant through a power purchase arrangement that requires it to fund a portion of the capital and operating costs of the plant.

This chapter addresses accounting issues for joint plant and other similar arrangements involving power plants and other utility assets (e.g., transmission).

15.2 Accounting for joint plant

In the utility and power industry, it is established practice that joint plant is accounted for using proportionate consolidation. SAB Topic 10.C, *Jointly Owned Electric Utility Plants* (SAB Topic 10.C), discusses the accounting for typical utility joint plant arrangements and requires certain related disclosures (see UP 21). In general, utilities have followed proportionate consolidation for joint plant based on historical industry practice and reference to SAB Topic 10.C (codified in ASC 980-360-S99-1), as well as consideration of the guidance in ASC 970-810-45-1¹ and in an AICPA Issues Paper, *Joint Venture Accounting*. General information on proportionate consolidation is included in FSP 18.6.

In evaluating the accounting for new joint plant arrangements, reporting entities should consider the description of joint plant arrangements in SAB Topic 10.C and the guidance on accounting for undivided interests in ASC 970-810-45-1. Figure 15-1 highlights key accounting considerations.

Figure 15-1

Evaluating the application of proportionate consolidation

ASC 970-810-45-1 criterion	Key considerations
Ownership should be in the form of undivided interests in the underlying assets (UP 15.2.1)	<ul style="list-style-type: none"> □ If the plant is held in a legal entity, joint plant guidance is not applicable; entity should be evaluated under other applicable U.S. GAAP, such as consolidation (ASC 810) or the equity method of accounting (ASC 323).

¹ Guidance originally issued in paragraph 11 of AICPA Statement of Position No. 78-9, *Accounting for Investments in Real Estate Ventures*.

ASC 970-810-45-1 criterion	Key considerations
Each owner should be able to independently approve decisions on financing, development, sales or operations relating to its undivided interest without approval by other owners (UP 15.2.2)	<ul style="list-style-type: none"> □ Owners of joint plant in the utility and power industry are typically individually responsible for financing their share of construction and operations and managing their own sales. □ The physical nature of power plants (i.e., portions are not separable) results in some necessary sharing of decision making, as discussed in SAB Topic 10.C.
Each investor should only be entitled to its share of income and responsible for its share of expenses from the joint operations (UP 15.2.3)	<ul style="list-style-type: none"> □ Interests in income and responsibility for expenses should be specified in the operating agreement(s).
Each investor is only severally liable for debts or liabilities that it incurs in connection with its interest (UP 15.2.4)	<ul style="list-style-type: none"> □ Several liability should be specified in the operating agreement(s).

Considerations in assessing whether the proportionate consolidation method is appropriate are discussed in the following sections.

15.2.1 Ownership of the plant by undivided interests

The first criterion requires that the investors in the plant or other utility assets own undivided interests in the underlying assets.

ASC 970-810-45-1(a)

The real property is owned by undivided interests.

Each owner should have title to its undivided interest in the property as tenant in common with the other owners. An undivided interest is an ownership arrangement in which two or more parties jointly own property, and title is held individually to the extent of each party's interest. To meet this criterion, ownership through undivided interests should be specified in the operating agreement and other related legal agreements.

If the plant or other utility assets are held in a separate legal entity (such as a limited liability company, limited partnership, or other special purpose entity), the owners typically do not have undivided interests in the underlying assets, but rather debt or equity interests in a legal entity. In such cases, the arrangement does not qualify for application of proportionate consolidation accounting. See UP 9 for information on accounting for investments in power plant entities.

15.2.2 *Approvals by owners*

The second criterion addresses how decisions are made regarding the financing, development, sale, or operations of the property.

ASC 970-810-45-1(b)

The approval of two or more of the owners is not required for decisions regarding the financing, development, sale, or operations of real estate owned.

In assessing whether proportionate consolidation is appropriate, SAB Topic 10.C provides additional context for public companies regarding the financing and operations of typical joint plant projects.

Excerpt from SAB Topic 10.C

During the construction period a participating utility finances its own share of a utility plant using its financial resources and not the combined resources of the group. . . . When a joint-owned plant becomes operational, one of the participant utilities acts as operator and bills the other participants for their proportionate share of the direct expenses incurred.

Within this context, the industry considers certain factors in evaluating whether proportionate consolidation is appropriate for a joint plant arrangement:

□ *Financing*

Each party should be responsible for providing its own financing.

□ *Sale*

Autonomy in making sale decisions about an ownership interest is another important factor. Joint plant arrangements may include provisions to protect the rights of other owners such as a right of first offer or a limitation on sale of partial interests. Reporting entities should assess whether individual owners can act independently to sell their interests. Restrictions on the ability of an owner to sell or encumber its interest may result in this criterion not being met.

□ *Development and operations*

The components of a power plant cannot be physically separated and operated independently. Power plants with multiple units also have common facilities, which are integral to the overall operation. Due to the physical nature of joint plant, it is necessary for the parties to agree on certain development and operational matters, such as significant budget decisions, maintenance, and contracting. As a result, joint plant arrangements generally establish a management committee comprising the owners (or owner representatives) that has oversight of the plant and is responsible for key development and operating decisions.

Application of the proportionate consolidation guidance for joint plant arrangements as described is common practice in the utility and power industry and should not be analogized to other scenarios. Utilities and power companies entering into new joint plant arrangements should evaluate the relevant guidance to determine whether proportionate consolidation is appropriate.

15.2.3 Responsibility for pro rata share of income and expenses

The third and fourth criteria pertain to how income and expenses are allocated to the different owners.

Excerpt from ASC 970-810-45-1

- c. Each investor is entitled to only its pro rata share of income.
- d. Each investor is responsible to pay only its pro rata share of expenses.

To meet these criteria, each investor can only be entitled to its share of income generated from the output of the plant and its share of expenses. Often, such amounts are based on the relative shares and/or the dispatch decisions of the parties.

15.2.4 Responsibility for liabilities

To meet this criterion, each investor should be severally liable only for debt or liabilities that it incurs in connection with its proportionate interest in the plant.

ASC 970-810-45-1(e)

Each investor is severally liable only for indebtedness it incurs in connection with its interest in the property.

An arrangement that makes owners pay for a proportionate share of costs in the event the other owners fail to pay would not meet this criterion.

15.3 Applicability of variable interest entity guidance

In general, we would not expect typical joint plant arrangements to be subject to consolidation under ASC 810. However, it is important as a first step to consider whether a legal entity is involved and whether ASC 810 should be applied. The SEC highlights this concept in Footnote 1 of SAB Topic 10.C.

Excerpt from SAB Topic 10.C

Before considering the guidance in this SAB Topic, registrants are reminded that the arrangement should be evaluated in accordance with the provisions of ASC Topic 810.

In a typical joint plant arrangement, there is no single legal entity holding the plant that would be subject to evaluation under ASC 810. Therefore, joint plant interests of this nature would not be subject to consolidation under ASC 810. Instead, these interests are usually accounted for using a specific accounting model that follows the legal form of the ownership interest.

In contrast, if a plant is constructed and operated within a separate legal entity established to hold and finance the arrangement, the entity may be subject to consolidation or the equity method of accounting and joint plant accounting is not applicable. See UP 9 for information on accounting for interests in power plant entities and UP 10 for information and considerations related to consolidation.

15.4 Proportionate consolidation accounting

When applying the proportionate consolidation model, a reporting entity should record its basis in the assets, liabilities, revenues and expenses of the joint plant in an amount equal to its proportionate share of each item. Common considerations in applying proportionate consolidation to joint plant are discussed in this section.

15.4.1 Joint plant assets, liabilities, and contractual arrangements

Each owner should record its share of the assets and liabilities associated with the joint plant. Although there may be transactions or accounting considerations related to the assets and liabilities that apply broadly to the group of investors, each is individually responsible for making decisions related to their own accounting. Examples of accounting decisions and considerations may include:

- Developing capitalization policies
- Establishing depreciable lives and methods
- Evaluating potential impairments
- Developing assumptions related to asset retirement obligations
- Evaluating contingent liabilities
- Determining the appropriate accounting for supply contracts or other contractual arrangements such as power purchase agreements (e.g., treatment as a lease, derivative, or executory contract)
- Valuing contracts accounted for as derivatives

This list is not all-inclusive. Reporting entities accounting for joint plant using proportionate consolidation should consider how to account for any balance or transaction relating to its interest. It is common for individual owners to account for joint plant interests differently, depending on their accounting policies and intentions with respect to their interest.

15.4.2 *Leasing considerations*

An owner of an undivided interest in a plant may enter into a power purchase arrangement to sell the output from its undivided interest, or may otherwise enter into a legal-form lease of its undivided interest. Such arrangements may be for all, or a portion of, the undivided interest. In such situations, a question arises as to whether ASC 840 applies to the contractual arrangement.

ASC 840 specifically states that it does not address whether an undivided interest or a pro rata portion of property, plant, and equipment could be the subject of a lease. However, ASC 840-10-15-4 indicates that a physically distinguishable portion of property, plant, or equipment can be the subject of a lease if the relevant criteria are met.

Question 15-1

Can an undivided interest in a plant be the subject of a lease?

PwC response

Yes. As discussed in UP 15.2, practice in the utility and power industry is to account for undivided interests in joint plant using proportionate consolidation. This method requires a reporting entity to account for an undivided interest as if it were a separate unit of property (i.e., the reporting entity records plant and related depreciation expense representing its undivided interest in the plant). Furthermore, if a reporting entity disposes of its interest in a joint plant, it applies the sales guidance in ASC 360-20 for real estate (see UP 15.4.3).

Lease accounting applies to separate units of property, plant, or equipment. Therefore, because joint plant is accounted for in a manner that depicts the interest as a separable portion of property, we believe lease accounting is applicable for either (1) a lease of an undivided interest or (2) an arrangement pertaining to an undivided interest (such as a power purchase agreement) that would otherwise meet the criteria to be accounted for as a lease under ASC 840. In addition, if there is a sale-leaseback of an undivided interest, the sale-leaseback guidance in ASC 840 would apply.

See UP 2 for further information on leases of power plants.

15.4.3 *Disposal of joint plant*

Most joint plant is real estate as defined in the accounting literature (see UP 2 for further information). The guidance applicable to the sale of real estate is contained in ASC 360-20. Figure 15-2 summarizes the applicable guidance for potential sale transactions involving the sale of an undivided interest in a plant.

Figure 15-2
 Sale of an undivided interest in a plant

Ownership interest	Transaction	Guidance
Ownership of an entire plant	Sale of an undivided interest in the plant	Partial sales guidance in ASC 360-20-40-46 through 40-49
Ownership of an undivided interest in a plant	Sale of the entire undivided interest	General sales guidance in ASC 360-20
Ownership of an undivided interest in a plant	Sale of a portion of the undivided interest	Partial sales guidance in ASC 360-20-40-46 through 40-49

The accounting for the sale and any potential gain or loss recognition will depend on the guidance applied, in particular the conclusions regarding the transfer of risks and rewards.

Chapter 16:

Government incentives

16.1 Chapter overview

Many active government programs provide assistance and different forms of incentives to develop power and utility projects. Figure 16-1 highlights some of the more recent government programs available to utilities and power companies, as well as related accounting, auditing, and compliance considerations.

Figure 16-1

Summary of current energy-related government incentives

Program	Description	Accounting, auditing, and compliance considerations
Investment tax credits (ITCs) and production tax credits (PTCs)	<ul style="list-style-type: none"> □ Can be elected on different types of renewable energy property □ Deadlines extended for many renewable technologies 	<ul style="list-style-type: none"> □ ITC — grant accounting model may apply □ PTC — traditional tax credit accounting applies □ No specified audit or compliance requirements; however, subject to recapture
Other cash grants	<ul style="list-style-type: none"> □ Cash grant may be received upfront or on a reimbursement basis □ Applies to a range of activities, including infrastructure and energy efficiency □ Federal, state, and local 	<ul style="list-style-type: none"> □ Grant accounting model applies □ May be subject to numerous grant-specific or other government audit requirements

16.1.1 Government grants

Government grants may include significant compliance requirements, including the potential for independent audits and audits by various government agencies. Assessing the probability that the reporting entity will be able to comply with all grant requirements is a key consideration in the recognition process (see UP 16.2.1). Therefore, reporting entities should have compliance programs and monitoring procedures that are sufficient to ensure ongoing compliance with the applicable requirements. Figure 16-2 provides a high-level summary of government grant compliance requirements.

Figure 16-2
Compliance, reporting, and audit requirements for government grants

Source of requirement	Compliance and reporting requirements	Audit requirements
Code of Federal Regulations (CFR) and Federal Acquisition Regulation	<ul style="list-style-type: none"> □ Umbrella of rules and regulations (e.g., Title 10 of the Code of Federal Regulations (CFR) pertains to funding received by DOE) □ Key areas include: allowability of activities and costs; cash and property management; Davis-Bacon Act; general eligibility; cost sharing; use of funds; procurement, suspension, and debarment; real property rules □ Filing requirements include U.S. GAAP financial statements 	<ul style="list-style-type: none"> □ Government entities and not-for-profit entities have specified audit requirements if more than \$750,000 in federal spending in one year □ Other entities may have other audit requirements (such as in accordance with DOE guidelines)
American Recovery and Reinvestment Act	<ul style="list-style-type: none"> □ Same requirements as CFR and Federal Acquisition Regulation, with additional focus on Buy American Act; Davis-Bacon Act; jobs creation/retention; Code of Business Ethics and Conduct; False Claims Act; lobbying restrictions, segregation of costs □ Filing requirements may include quarterly reporting on spending, project status, jobs creation, information on sub-awards and executive pay 	<ul style="list-style-type: none"> □ Varies based on type of funding received
Grant-specific	<ul style="list-style-type: none"> □ Can vary; specified in the award 	<ul style="list-style-type: none"> □ Can vary; specified in the award

In addition to the requirements noted in Figure 16-2, there may also be requirements under the Internal Revenue Code, such as for tax credits (see UP 16.3 for more information on ITC). With respect to grants, the audit requirements can vary and audits may be performed by different parties. Reporting entities receiving government grants may be subject to one or more audits by government agencies, such as the DOE Inspector General, defense contract auditors, or external independent accountants. In general, the grant agreement will specify its audit requirements. However, it is possible the grant agreement will be silent on the topic and an audit still may be required under 10 CFR 600.316.

Reporting entities should refer to the grant agreement, other related agreements, and information on the DOE website for specific information about the grant being evaluated.

16.2 Accounting for government grants

U.S. GAAP does not specify the accounting for government grants received by “for-profit” enterprises. Practice generally refers to IAS 20, *Accounting for Government Grants and Disclosure of Government Assistance*, to determine the most appropriate accounting for government grants when no other specific literature is on point.¹ IAS 20 provides guidance on recognition and measurement, presentation, repayment, and disclosure for the following types of government grants:

- Grants related to assets — government grants requiring an entity to purchase, construct, or otherwise acquire long-term assets to qualify
- Grants related to income — government grants other than those related to assets

The criteria for initial recognition are the same for grants related to assets and grants related to income. Subsequent recognition and financial statement presentation varies depending on the type and nature of the grant. In addition, in certain fact patterns the receipt of a grant for a renewable power plant may impact the classification of a lease of the plant. See Question 2-26 for further information.

Question 16-1

What guidance should be applied in a for-profit entity’s accounting for government grants?

PwC response

Practice generally refers to IAS 20 by analogy. U.S. GAAP does not specify the accounting for government grants received by “for-profit” enterprises. ASC 958, *Not-for-Profit Entities* (ASC 958), establishes standards of financial accounting for all entities (not-for-profit and other business enterprises) that receive contributions. Under this model, contributions are generally recognized in the period received or, if conditional, when the conditions on which they depend are substantially met. However, transfers of assets from governmental units to business entities are specifically excluded from the scope of ASC 958.

Excerpt from ASC 958-605-15-6

The guidance in the Contributions Received Subsections does not apply to the following transactions and activities: . . . (d) Transfers of assets from governmental units to business entities.

Certain grants are transfers from the U.S. federal government and therefore would be subject to this scope exclusion.

¹ A current list of Issues Papers of the Accounting Standards Division of the AICPA indicates that an October 1979 paper, *Accounting for Grants Received from Governments*, was considered superseded by IAS 20.

Prior to the Codification, the Basis for Conclusions of FASB Statement No. 116, *Accounting for Contributions Received and Contributions Made*, stated that the FASB specifically excluded these types of transfers from its scope because of “specific complexities that may need special study.” In addition to the specific scope exclusion, we believe the contributions received model does not properly reflect the economic substance of the capital grants, which offset a portion of the cost of a long-term asset. Recognizing these grants immediately in income, while the underlying property is amortized over its useful life, would not result in financial statement recognition that reflects the substance of the transaction. Since there is not specific GAAP, reporting entities should consider analogy to IAS 20.

16.2.1 *Initial recognition*

Prior to initial recognition, a reporting entity should assess whether there is reasonable assurance that it will be able to comply with the grant requirements and that the grant will be received.

IAS 20, paragraph 8

A government grant is not recognised until there is *reasonable assurance* that the entity will comply with the conditions attaching to it, and that the grant will be received. Receipt of a grant does not of itself provide conclusive evidence that the conditions attaching to the grant have been or will be fulfilled. [Emphasis added]

Initial recognition of a government grant should occur once a reporting entity believes it is probable that it will comply with the grant conditions and that it will be received. This may occur at various points in the process, potentially even after the funds are received, depending on the specific criteria of the grant and the reporting entity’s individual facts and circumstances. Factors to consider in making this assessment include:

□ *Conditions of the grant*

Has the reporting entity performed sufficient procedures to ensure that all grant conditions have been met? Are there adequate internal controls in place over amounts submitted as part of the grant process? Is there a process in place to comply with ongoing requirements?

□ *External audit*

If applicable, has an external audit been completed that supports the amount of the grant and compliance with grant conditions?

□ *Government oversight*

What is the government oversight process prior to granting funds? Are amounts received subject to audit? Are amounts received subject to adjustment after funds have been disbursed?

Depending on the type of grant, reporting entities may be subject to audit and other types of review and scrutiny by the disbursing agent at various points in the process. An audit may identify compliance violations and could clawback portions of the grant. As a result, the amount of the grant may be subject to change.

The timing of recognition of grants may involve judgment because of the lack of agency scrutiny or audit prior to receipt of the funds. In general, funds may be received prior to required compliance audits or any other audits conducted by the granting agency. In addition, certain grants may have ongoing requirements that subject the reporting entity to recapture or return of the grant if the reporting entity fails to meet the stipulations in a future period. Therefore, in addition to assessing compliance prior to initial recognition, a reporting entity should ensure that it has sufficient controls in place over the funds submitted for reimbursement and compliance requirements. Further, reporting entities should implement ongoing monitoring procedures, if applicable, based on the grant requirements.

In summary, reporting entities should ensure that they have met all terms and conditions and consider all available evidence prior to recognition of a grant. If recognition occurs before payment, the reporting entity should record a receivable.

Question 16-2

How is the “reasonable assurance” threshold in IAS 20 interpreted?

PwC response

Paragraphs 7 and 8 of IAS 20 indicate that a government grant should not be recognized until there is *reasonable assurance* that the grant will be received and that the reporting entity will comply with the specified conditions. Reasonable assurance is not defined within IFRS literature, and there are no bright lines when considering this requirement. We believe it would be difficult to justify recognition of a grant unless the reporting entity believes it is probable that it will comply with the conditions attached to the grant and that the grant will be received.

Question 16-3

If a reporting entity believes it meets the criteria for recognition of a grant after the end of the reporting period but before the financial statements are issued, should the grant be recognized in those financial statements?

PwC response

Generally, no. Although the potential for receiving the grant was known as of the balance sheet date, if a reporting entity has not yet met the criteria for recognition as of the balance sheet date, we believe subsequent receipt of the grant is a nonrecognized subsequent event. In these situations, reporting entities should consider disclosing the status and expected impact of the grant.

ASC 855, *Subsequent Events*, provides guidance on whether to recognize subsequent events.

Excerpt from ASC 855-10-25-1

An entity shall recognize in the financial statements the effects of all subsequent events that provide additional evidence about conditions that existed at the date of the balance sheet, including the estimates inherent in the process of preparing financial statements.

Excerpt from ASC 855-10-25-3

An entity shall not recognize subsequent events that provide evidence about conditions that did not exist at the date of the balance sheet but arose after the balance sheet date but before financial statements are issued or are available to be issued.

As discussed in Question 16-2, we believe reporting entities that prepare financial statements under U.S. GAAP should be able to assert that it is probable funds will be received and that all conditions will be met prior to recognition of a grant. In general, the conditions attaching to a grant (e.g., approval after an audit) are not perfunctory. Therefore, such grants would be recognized in the period in which the recognition criteria are met.

However, the reporting entity should consider disclosure of significant nonrecognized events.

16.2.1.1 *Potential loss after initial recognition*

Reporting entities should follow the guidance on contingencies in ASC 450, *Contingencies*, when considering any potential loss after initial recognition. The reporting entity should derecognize any grant (or portion of a grant) if it becomes probable that the grant will have to be repaid.

Similar guidance is included in IAS 20, paragraph 32, which treats any potential repayments as a change in estimate. Amounts that are probable of repayment should be recorded as a reduction of the unamortized deferred credit (or as an increase in the capital asset in the case of an asset grant where the basis has been reduced). If the amount to be repaid is in excess of the remaining unamortized grant balance, the excess should be recorded as a loss in the income statement.

16.2.2 *Subsequent recognition*

Subsequent recognition guidance for government grants is discussed in IAS 20, paragraph 12.

IAS 20, paragraph 12

Government grants shall be recognised in profit or loss on a systematic basis over the periods in which the entity recognises as expenses the related costs for which the grants are intended to compensate.

IAS 20, paragraph 17, provides further guidance on the recognition period for grants related to capital assets.

IAS 20, paragraph 17

In most cases the periods over which an entity recognises the costs or expenses related to a government grant are readily ascertainable. Thus grants in recognition of specific expenses are recognised in profit or loss in the same period as the relevant expenses. Similarly, grants related to depreciable assets are usually recognised in profit or loss over the periods and in the proportions in which depreciation expense on those assets is recognised.

The framework provided by IAS 20 is used to distinguish situations in which amounts received may be recognized immediately in income from those in which a government grant should be deferred and recognized over the same period that the related asset is depreciated. Government grants should be recognized in the income statement in the same manner as the expenditure for which they are intended to compensate (immediately for grants related to income and over the life of the related asset for grants related to assets). For grants related to assets (such as Section 1603 grants), this recognition model links the grant received to the related capital asset and matches the timing of recognition of the grant with that of the related depreciation.

However, certain grants may have multiple elements that can present recognition challenges. Reporting entities should identify the conditions giving rise to costs and expenses that determine the periods over which the grant should be recognized. It will sometimes be appropriate to allocate part of the grant on one basis (capital) and part on another basis (income). Reporting entities should consider the basis for the grant award in evaluating the appropriate recognition period.

16.2.3 Considerations for regulated utilities

The accounting for a grant received by a regulated utility will depend on how the regulator treats the grant. If the regulator treats the grant as a reduction of utility plant to be recovered through rate base, in general, we believe the reporting entity should follow the models for asset-based grants discussed in UP 16.2 In such cases, the grant should usually be recognized as a reduction of utility plant, with depreciation reduced over the life of the property.

However, in some situations, the regulator may continue to provide for full recovery of the utility plant, while requiring separate return of the grant to the ratepayers. Return of the grant may occur over the same time period as recovery of the related plant or it may be accelerated (e.g., a regulator may require return of the grants over 5 years,

compared to a 20-year life for the underlying property). In these situations, the regulator has effectively decoupled the grant from the related asset: the regulated utility is still recovering the full cost of the underlying capital asset plus return over the life of the asset, and the benefit provided from the grant is being viewed by the regulator as a gain to be used to reduce other costs of service.

If the regulator separates return of the grant from recovery of the plant, we believe the grant should be treated as a separate unit of account and accounted for under a separate recognition model. In such cases, the regulator has treated the benefit of the grant as a liability owed to customers, separate from the capital asset. As a result, recognition of the grant as an offset to depreciation would no longer accomplish the IAS 20 objective of offsetting the costs for which the grant is intended to compensate, and the reporting entity would no longer apply the guidance in IAS 20. Instead, because of the intervention of the regulator, we believe the grant would be subject to regulatory accounting as a regulatory liability (a gain that the regulator mandates be given to customers). Prior to the Codification, this was addressed in the Basis for Conclusions of FASB Statement No. 71, *Accounting for the Effects of Certain Types of Regulation* (FAS 71), paragraph 79(c).

Excerpt from FAS 71, Basis for Conclusions, paragraph 79(c)

For rate-making purposes, a regulator can recognize a gain or other reduction of overall allowable costs over a period of time. . . . By that action, the regulator obligates the enterprise to give the gain or other reduction of overall allowable costs to customers by reducing future rates.

Consistent with the guidance in ASC 980-405-25-1(c), discussed in UP 17.4, the subsequent recognition of the regulatory liability should occur over the period during which the grant is returned to customers. The interaction of regulatory accounting with the receipt of grants is complex and the outcome is highly dependent on the specific facts and circumstances. In addition, the fact that a grant will be flowed through to customers will not always be transparent in rate orders or other regulator communications.

16.2.4 Accounting for deferred income taxes associated with government grants

As discussed in UP 16.3, reporting entities may elect to present the grants as an offset to plant or as a deferred credit on the balance sheet. Regardless of financial statement presentation, receipt of a grant generally creates an income tax timing difference and deferred income tax accounting would apply. ASC 740 addresses the accounting for a similar type of temporary difference in ASC 740-10-25-49 through 25-55 and ASC 740-10-45-22 through 45-24.² Under this guidance, the deferred tax asset is determined through a simultaneous equation that generates a corresponding decrease in the book basis of the related capital asset. An example of this treatment can be found in ASC 740-10-55-171 through 55-176 (formerly Example 1 of EITF 98-11).

² Originally issued as EITF Issue No. 98-11, *Accounting for Acquired Temporary Differences in Certain Purchase Transactions That Are Not Accounted for as Business Combinations* (EITF 98-11).

An acceptable alternative view is to recognize the deferred tax impacts of the transaction as an immediate adjustment to income tax expense, as suggested by ASC 740-10-25-20.

The decision to account for the deferred tax impacts associated with a grant temporary difference as a decrease to the basis of the property or as an immediate adjustment to income tax expense is an accounting policy election that should be consistently applied and disclosed.

16.3 *Investment tax credits*

Accounting for ITCs generally follows the guidance in ASC 740-10-25-45 through 25-46 and 740-10-45-26 through 45-28.³

ASC 740-10-25-46

While it shall be considered preferable for the allowable investment credit to be reflected in net income over the productive life of acquired property (the deferral method), treating the credit as a reduction of federal income taxes of the year in which the credit arises (the flow-through method) is also acceptable.

In accordance with this guidance, in a traditional ITC model, reporting entities may elect to recognize the ITC over the life of the related property (deferral method), similar to the grant model, or the benefit may be recognized in the year received (flow-through method). See TX 3.2.3 for further information on accounting for investment tax credits.

16.3.1 *Accounting and reporting for investment tax credits*

A reporting entity should follow its existing accounting policy consistent with the guidance in ASC 740-10-25-46. That is, either “flow through” the benefit to income in the tax computation during the period the benefit is generated, or defer and amortize the benefit over the life of the related property. These amounts would also be subject to analysis for uncertain tax positions under ASC 740.

In addition, similar to the recording of deferred income taxes on government grants (see UP 16.2.4), there are two acceptable approaches to provide for deferred income taxes on the book and tax basis differences created on initial recognition of the ITCs received under the American Recovery and Reinvestment Act of 2009. This decision is also an accounting policy election that should be consistently applied and disclosed.

³ Formerly Accounting Principles Board (APB) *Opinion No. 2, Accounting for the “Investment Credit,”* and APB *Opinion No. 4 (Amending No. 2), Accounting for the “Investment Credit.”*

Chapter 17:
Regulated operations

17.1 Chapter overview

Industry-specific accounting guidance for regulated operations is predominantly codified as ASC 980. Regulated utilities that meet certain criteria under ASC 980 are required to apply its guidance.

The purpose of ASC 980 is for financial reporting to reflect the economic effects of certain rate-regulated activities and actions taken by regulators that arise in the normal course of regulated operations. The basic premise of ASC 980 is that the actions of a regulator will impact the financial statements prepared for financial reporting purposes only if the action has an economic effect on the regulated utility and meets the requirements for recognition or deferral under the standard. A regulated utility should comply with U.S. GAAP applicable to entities in general with regard to its accounting and financial reporting. If it is also subject to ASC 980, the applicable provisions within that standard are applied as an adjustment to or in lieu of other U.S. GAAP (when specifically required by ASC 980).

ASC 980 provides guidance for (1) determining whether a reporting entity has regulated operations subject to rate-regulated accounting and (2) accounting for certain assets, liabilities, and transactions arising from regulated operations. This chapter addresses these requirements and the discontinuation of application and reapplication of ASC 980. See UP 18, UP 19, and UP 20 for further information on utility plant, income tax, and business combination issues, respectively, specific to regulated utilities.

17.2 Scope of ASC 980

As outlined in ASC 980-10-15-2, a reporting entity is required to apply ASC 980 if it meets three specified criteria.

- Rates are established by an independent third-party regulator or the entity's own governing board (UP 17.2.1)
- Rates are designed to recover costs of service (UP 17.2.2)
- Rates designed to recover costs can be charged to and collected from customers (UP 17.2.3)

A reporting entity should assess and document whether it continues to meet each of the criteria, setting forth the significant factors considered, at least annually or any time rate structures change or regulatory developments occur. The unit of account for the application of ASC 980 can be a transaction, a group of transactions, a separable operation of the reporting entity or the reporting entity in its entirety. The unit of account is based on the level at which the criteria in ASC 980-10-15-2 are met. The documentation should address the rationale for the determination of the unit of account if there are specific or different factors impacting various parts of the business (e.g., service territories, customer classes, or functional activity such as generation).

The determination of whether a reporting entity's rate structure continues to meet the criteria of ASC 980 should consider the totality of the evidence and all relevant facts.

The following discussion highlights considerations in making this assessment. The discussion is framed in the context of the entire business; however, similar factors would be considered in assessing a separable portion of the business (see UP 17.2.4).

17.2.1 *Rates are established by an independent third-party regulator or the entity's own governing board*

The first criterion for determining whether regulatory accounting applies to a reporting entity is that its rates for regulated services are established by an independent, third-party regulator or its own governing board.

ASC 980-10-15-2(a)

The entity's rates for regulated services or products provided to its customers are established by or are subject to approval by an independent, third-party regulator or by its own governing board empowered by statute or contract to establish rates that bind customers.

This criterion is straightforward and has not generated much controversy in application. If a third-party regulator sets the rates for a reporting entity, this criterion is usually met. This requirement is also met by self-regulated enterprises, such as governmental or quasi-governmental entities with a governing board responsible for setting customer rates (e.g., municipal water authorities and rural electric cooperatives).

17.2.2 *Rates are designed to recover costs of service*

The second criterion for determining whether rate-regulated accounting applies to a reporting entity is that its regulated rates are designed to recover its costs of providing the regulated services or products.

ASC 980-10-15-2(b)

The regulated rates are designed to recover the specific entity's costs of providing the regulated services or products. This criterion is intended to be applied to the substance of the regulation, rather than its form. If an entity's regulated rates are based on the costs of a group of entities and the entity is so large in relation to the group of entities that its costs are, in essence, the group's costs, the regulation would meet this criterion for that entity.

This criterion requires a cause-and-effect relationship between a reporting entity's costs and its rate base revenues. As a result, entities whose rates are regulated on a group or regional basis generally would not meet this criterion. Furthermore, the timing of cost recovery and the related frequency of ratemaking is important. A reporting entity should consider its rate case experience, including the design of its rates and timing of recovery, when determining whether this criterion is met. These factors are summarized in Figure 17-1.

Figure 17-1

Evaluating whether rates are designed to recover costs of service

Factors	Indicators that rates are cost-based	Indicators that rates are other than cost-based
Rate case activity	<ul style="list-style-type: none"> □ General rate cases occur at regular intervals or more frequently as necessary □ Regulatory lag periods are not extensive and are comparable to peers 	<ul style="list-style-type: none"> □ Sustained period of no rate cases □ Unusually long lag periods, causing the reporting entity to under-earn or over-earn
Rate design	<ul style="list-style-type: none"> □ Rates are designed to recover incurred costs plus a reasonable return on rate base □ Rate process incorporates actual and/or estimated costs in developing the revenue requirement and customer rates 	<ul style="list-style-type: none"> □ Rates are based on market or average industry costs or based on reporting entity performance (incentive-based rates) □ The revenue requirement has little or no connection to the reporting entity's cost of service
Periods of alternative ratemaking (e.g., rate freezes) (UP 17.2.2.1)	<ul style="list-style-type: none"> □ The utility may elect a return to cost-based regulation if the results of the alternative form of rate regulation do not provide cost recovery □ Alternative rate structure is temporary or for a short period, and cause and effect is still present 	<ul style="list-style-type: none"> □ Regulator determines if and when the utility may return to cost-based regulation □ Permanent, long period, or no stated timeframe
Cost uncertainty	<ul style="list-style-type: none"> □ Highly volatile costs (such as fuel) are recovered via a tracker or other similar recovery mechanism □ Special rate cases are provided for nonrecurring, unusual, significant costs or gains (e.g., major storm damage, sale of facilities) 	<ul style="list-style-type: none"> □ Utility is required to manage volatile costs to a target; shareholders are subject to the risks and rewards of deviation from that target □ No interim adjustments to rates to compensate for potentially significant losses or gains; no true-up to actual costs if they deviate from expected

Factors	Indicators that rates are cost-based	Indicators that rates are other than cost-based
Disallowances	<ul style="list-style-type: none"> □ Disallowances may occur on occasion but are limited in frequency and amount □ Regulator demonstrates willingness to allow recovery of costs plus return 	<ul style="list-style-type: none"> □ Frequent or recurring disallowances occur, impacting the utility's ability to recover its costs □ Implementation of phase-in plans

Whether a reporting entity meets this criterion is a matter of judgment that should be based on all relevant factors. Cost-based ratemaking does not necessarily result in a dollar-for-dollar pass-through of costs. Ratemaking involves projections and assumptions, and actual costs will differ from estimated amounts used in developing rates.

Changes in cost structure may not be captured immediately in rates. Some delay in the timing between when a cost is incurred and when recovery begins (referred to as regulatory lag) is generally expected and would not normally impact the conclusion that this criterion is met. In addition, as described in Figure 17-1, occasional regulatory disallowances likely would not impact the assessment. However, a regulated utility should consider whether it continues to comply with this criterion if it is receiving frequent or recurring negative rate decisions or disallowances.

Question 17-1

Does the term “entity’s costs” used in the second and third criteria of ASC 980-10-15-2 mean all costs or only allowable costs?

PwC response

We interpret the term “entity’s costs” to mean allowable costs.

Definition from ASC 980-10-20

Allowable Costs: All costs for which revenue is intended to provide recovery. Those costs can be actual or estimated. In that context, allowable costs include interest cost and amounts provided for earnings on shareholders’ investments.

The definition of allowable costs means that for a reporting entity to qualify as a regulated utility, rates should be set to recover its cost of service and a reasonable rate of return. When considering whether the second and third criteria of ASC 980-10-15-2 are met, a reporting entity should perform its evaluation by considering only those costs that are allowable by the regulator. The utility should not consider or account for costs not associated with the regulated portion of the business using rate-regulated accounting.

See UP 17.3.1 for further information on allowable costs and how they compare to incurred costs. Also, see Question 17-5 as it relates to treatment of the equity return component for regulatory assets.

17.2.2.1 *Impact of alternative ratemaking*

Evaluation of the second criterion requires additional judgment if the regulated utility is subject to any form of ratemaking that introduces uncertainty about the cause-and-effect relationship between costs and rates. Prior to the codification, paragraph 65 of FAS 71 elaborated on this point.

Excerpt from FAS 71, paragraph 65

If rates are based on industry costs or some other measure that is not directly related to the specific enterprise's costs, there is no cause-and-effect relationship between the enterprise's costs and its revenues. In that case, costs would not be expected to result in revenues approximately equal to the costs; thus, the basis for the accounting specified in this Statement is not present under that type of regulation.

Consistent with this guidance, adoption by a regulator of any alternative forms of ratemaking, such as rate freezes, performance or incentive rates, price caps, or discounting, would call into question whether ASC 980 applies. If the utility implements alternative or nontraditional forms of ratemaking, it should carefully evaluate whether it meets or continues to meet the ASC 980-10-15-2(b) criterion.

Deferred recovery plans

In some jurisdictions, regulators have adopted deferred recovery plans in response to significant increases in costs. These plans vary, but typically provide for rates to remain fixed or increase moderately with a tracking mechanism to capture costs in excess of the level allowed in current rates. This is different from a standard tracker that is meant to capture amounts in excess of or below an estimate of current costs, with adjustment of rates to compensate over the short-term.

Costs subject to a deferred recovery plan may include purchased power costs, operations and maintenance costs, depreciation, or interest. A regulated utility subject to these types of rate arrangements should consider not only whether the uncollected costs qualify for deferral as a regulatory asset but whether it continues to meet the ASC 980-10-15-2(b) criterion. The fact that a regulator is unwilling to approve current rates based on the current cost of service calls into question the ability to meet this basic premise of regulatory accounting.

Rate freezes

Regulators may issue rate orders that freeze rates over a period of time, providing a regulated utility with limited ability to adjust its prices. Although regulatory oversight typically remains in place and a return to cost-based ratemaking may be expected, rate freezes and similar programs create uncertainty about whether an entity

continues to meet the scope criteria for application of ASC 980. Factors to consider in evaluating the potential impact of a rate freeze include:

- Length of the rate freeze
- Expected stability of costs during the rate freeze period
- Rate adjustments for specific events (e.g., tax law changes, significant changes in fuel costs, unusual storm damage)

A rate freeze extending over a period of several years, lack of regulator rate action or formal rate proceeding after a period of unchanged rates, or an inflexible rate program that fails to adjust for volatile costs, such as fuel, result in a presumption that the reporting entity does not meet the ASC 980-10-15-2(b) criterion. Relevant factors to consider in assessing whether this presumption can be overcome may include predictability of costs during the rate freeze period, the nature of ongoing cost filings (if any), involvement or participation of interveners in evaluating cost filings, and periodic regulatory oversight of the level of costs and earnings.

Rate discounts

In some situations, a regulated utility may provide rate discounts to all customers or to a particular customer class. Sustained rate discounts also create uncertainty about whether the ASC 980-10-15-2(b) criterion is met. Subsidization of discounts for one customer class by other customer classes may be an indication that rates are cost-based on an entity-wide basis. If, however, the level of discounting becomes significant, it may indicate that the criteria for application of ASC 980 are not met for the portion of the business in which customers receive the discount.

Index-based rates

In some jurisdictions, the regulator may develop rates for fuel or other costs based on a market index, instead of the reporting entity's specific costs for providing the service. In other instances, all or a portion of base rates may include provisions for an automatic rate change based on changes in a specified index. These mechanisms may not be directly tied to the reporting entity's cost of providing service. We do not believe adoption of an index-based mechanism automatically precludes application of ASC 980 to that portion of the business. However, regulated utilities should evaluate any index or market-based mechanism with skepticism. In evaluating this type of mechanism, regulated utilities should consider how closely the index mirrors actual costs and whether it will continue to reflect underlying costs over the entire period it is in effect.

17.2.3 *Rates designed to recover costs can be charged to and collected from customers*

The third criterion that must be met to apply ASC 980 is that a regulated utility will be able to charge to and collect from its customers rates that will recover its costs.

Excerpt from ASC 980-10-15-2(c)

In view of the demand for the regulated services or products and the level of competition, direct and indirect, it is reasonable to assume that rates set at levels that will recover the entity’s costs can be charged to and collected from customers. This criterion requires consideration of anticipated changes in levels of demand or competition during the recovery period for any capitalized costs. This last criterion is not intended as a requirement that the entity earn a fair return on shareholders’ investment under all conditions. . . . For example, mild weather might reduce demand for energy utility services. . . . The resulting decreased earnings do not demonstrate an inability to charge and collect rates that would recover the entity’s costs; rather, they demonstrate the uncertainty inherent in estimating weather conditions.

As noted in the excerpt, the FASB recognized that a regulated utility may not earn a fair return in all circumstances, such as when there are changes in consumption due to weather or economic circumstances. In such cases, utilities will need to exercise judgment to determine if this criterion is met. Key positive and negative factors to consider are included in Figure 17-2.

Figure 17-2
Assessing whether rates will recover costs

Factors	Indicators: able to charge and collect cost-based rates	Indicators: unable to charge and collect cost-based rates
Regulation/ legislation	<ul style="list-style-type: none"> □ Monopolistic operating environment in which rates are regulated □ Few choices of suppliers for the portion of the business being evaluated 	<ul style="list-style-type: none"> □ Deregulation legislation has been or will soon be enacted □ Unbundling of services that enables existing customers to bypass the utility, creating stranded or unrecoverable investment
Competitive environment	<ul style="list-style-type: none"> □ No issues in charging and collecting rates designed to recover incurred costs plus a reasonable return □ Rates for customer classes are consistent with a cost recovery model (i.e., certain classes do not subsidize others) □ Rates are consistent with neighboring utilities 	<ul style="list-style-type: none"> □ Prices discounted below what is authorized by the regulator due to competition (thereby preventing the reporting entity from recovering its costs) □ Significant disparity among the rates charged to different customer classes (i.e., one customer class significantly subsidizes another) □ Rates are higher than those of neighboring utilities or alternative competitive sources □ Excess capacity or significant loss of customers

Factors	Indicators: able to charge and collect cost-based rates	Indicators: unable to charge and collect cost-based rates
Timing of rate cases	<ul style="list-style-type: none"> □ Reasonable level of lag between costs being incurred and their inclusion in rates 	<ul style="list-style-type: none"> □ Significant time between rate cases, reducing the linkage between costs and rates and increasing the likelihood that the utility's specific costs will not be recovered through rates

The utility should consider a number of factors related to the regulatory, legal, and market environment to support whether it will be able collect revenue sufficient to recover its costs. As noted in Figure 17-2, the guidance provides that existence of an exclusive franchise with minimal competition from other services or products would provide a reasonable expectation that this criterion is met. However, this criterion would not be met if market or other structural factors exist (e.g., competition in the regulated utility's service territory or a dramatic decline in demand) that would prevent the utility from charging rates to recover its costs, regardless of the regulator's actions.

This criterion also requires that the utility be able to continue charging rates sufficient to recover costs, considering the potential impact of competition or changes in demand during the recovery period for any capitalized costs. For example, the introduction of competition into the service territory could have a significant effect on a utility's ability to charge and collect rates from customers set at levels to recover its cost of service. The shift in the landscape from a cost-based monopolistic environment to a competitive, market-based structure may occur over a period of time and utilities will need to apply judgment when considering changes in the environment (see UP 17.6).

17.2.4 Application to a portion of a reporting entity's operations

In accordance with ASC 980-10-15-4, if only some of a reporting entity's operations are subject to regulation, and those operations meet the criteria in ASC 980-10-15-2, the utility should apply rate-regulated accounting only to that portion of its operations. Although there is no specific guidance on what constitutes "some of an entity's operations," the guidance on discontinuation in ASC 980 can be helpful (see UP 17.8.1 for further information on how to define a separable portion of a business).

Question 17-2

Would a group of costs (e.g., natural gas costs) qualify as a separable portion of the business?

PwC response

It depends. ASC 980 applies to a separable portion of the business if the operations qualify. This analysis may be straightforward when a reporting entity has a distinct business unit or has operations within a customer jurisdiction that clearly meet the

criteria for application of ASC 980. However, analyzing whether a specific asset or group of costs are subject to regulation and recovery may be complex. Determining whether the asset or group of costs is clearly specified in a rate order or other evidence that would support regulatory accounting, including the means and timing of cost recovery, is key to this analysis.

For example, assuming all of the criteria in ASC 980 are met, a pipeline expansion for which capital and operating expenses will be recovered through rates imposed by a regulator may qualify for regulatory accounting if the related capital and operating costs are segregated such that it is clear which costs are being recovered through a cost-of-service mechanism. Similarly, if a reporting entity does not qualify for application of ASC 980 to its entire business but has cost-of-service regulation for one aspect of its costs (e.g., fuel costs), it may qualify for rate-regulated accounting for those costs, assuming the other criteria of ASC 980 are met.

The application of ASC 980 to a group of costs is highly judgmental and may not be appropriate in many circumstances.

17.3 *Regulatory assets*

One of the primary areas in which accounting by regulated utilities differs from unregulated entities is regulated utilities' ability to defer certain expenditures as regulatory assets that would otherwise be expensed under U.S. GAAP. Specific criteria exist for the recognition and measurement of regulatory assets as summarized in Figure 17-3.

Figure 17-3

Key areas of accounting consideration for regulatory assets

Area	Considerations
Initial recognition and measurement (UP 17.3.1)	<ul style="list-style-type: none"> □ Incurred costs may be capitalized as a regulatory asset if the amounts are probable of recovery through rates. □ Regulatory assets are initially measured as the amount of the incurred cost. □ If a cost does not meet the criteria for deferral as a regulatory asset at the date incurred, it should be expensed; a regulatory asset may subsequently be recorded if and when the criteria for recognition are met.
Subsequent measurement (UP 17.3.2)	<ul style="list-style-type: none"> □ Regulatory assets are typically amortized over future periods consistent with the period of recovery through rates. □ If all or part of an incurred cost recorded as a regulatory asset is no longer probable of being recovered, the amount that will not be recovered should be written off to earnings. □ If a regulator subsequently allows recovery of costs that were previously disallowed, a new asset is recorded; classification of the new asset depends on how the asset would have been classified had it been previously allowed.

The accounting framework for recognition and measurement of regulatory assets is discussed in the following sections, including consideration of specific types of common regulatory assets.

17.3.1 Initial recognition and measurement

ASC 980-340-25-1 states that an entity should defer all or part of an incurred cost that would otherwise be charged to expense if it is probable that the specific cost is subject to recovery in future revenues.

17.3.1.1 Incurred cost

When considering whether to capitalize a cost that would otherwise be expensed, it is important to understand the distinction between incurred costs and allowable costs, as only incurred costs qualify for capitalization as regulatory assets under ASC 980-340-25-1.

Definitions from ASC 980-10-20

Incurred Cost: A cost arising from cash paid out or [an] obligation to pay for an acquired asset or service, a loss from any cause that has been sustained and has been or must be paid for.

Allowable Cost: All costs for which revenue is intended to provide recovery. Those costs can be actual or estimated. In that context, allowable costs include interest cost and amounts provided for earnings on shareholders' investments.

The terms "allowable cost" and "incurred cost" are not interchangeable. By their nature, allowable costs are broader than incurred costs, and not all allowable costs will meet the definition of an incurred cost. Examples of allowable costs that are not incurred costs include:

- A component for earnings on rate base (except as specifically allowed for allowance for funds used during construction)
- A provision for recovery of similar costs that will be incurred in the future
- Compensation for opportunity costs (such as margin on lost revenue)

These costs do not meet the definition of incurred costs because they do not result from a past event, transaction, or loss that will require payment in cash.

Question 17-3

Are costs that would be recorded in other comprehensive income absent rate-regulated accounting considered incurred costs?

PwC response

Yes. In considering the definition of an incurred cost, the key point is that it represents “a loss from any cause that has been sustained and has been or must be paid for.” Amounts deferred in other comprehensive income (such as an unrecognized net loss on a pension obligation, unrealized losses on available-for-sale securities, and derivative losses on cash flow hedges) all represent obligations of the reporting entity arising from past events. The classification of these expenses as part of other comprehensive income (or loss) instead of net income (or loss) does not change their underlying nature.

Consistent with this conclusion, mark-to-market accounting for securities classified as available-for-sale should not render results on the balance sheet for unrealized gains or losses that are different from the impact of realized gains or losses. If future regulatory rates will be adjusted to reflect investment experience, then the impact of applying ASC 320 should have a corresponding impact to an associated regulatory asset or liability, rather than adjusting earnings or other comprehensive income. We believe this premise is also applicable to other types of amounts deferred in other comprehensive income.

Question 17-4

Are unrealized losses on derivative contracts considered incurred costs?

PwC response

Yes. We believe unrealized losses qualify as incurred costs because the losses are recognized within the carrying value of the derivative recorded on the balance sheet, and would be sustained by the reporting entity if the contract were to be terminated at the measurement date. Furthermore, we believe unrealized gains may represent a liability that should be returned to the ratepayer.

The evaluation of unrealized gains and losses on derivatives should follow the conclusion reached for realized gains and losses on the related contracts. If a reporting entity concludes that commodity costs qualify for deferral under a regulatory mechanism, it should also defer unrealized gains and losses instead of immediately recognizing such amounts in income.

Question 17-5

Can a regulated utility recognize the equity component of a carrying charge as a regulatory asset?

PwC response

Generally, no. Regulated utilities often receive approval for a return on regulatory assets based on the blended cost of debt and equity. ASC 980 explicitly prohibits the recognition of the equity component of the return because shareholder return is not an incurred cost, but rather represents an allowed cost. Therefore, the regulated utility should compute the carrying charge on regulatory assets by using only the debt

component. There are two exceptions to this rule: AFUDC (allowance for funds used during construction) equity (UP 18.3) and alternative revenue programs (UP 17.3.3.1).

We believe there are three acceptable approaches to calculate the appropriate carrying charge on regulatory assets. The selection of the methodology should be based on the regulated utility's specific facts and circumstances. These three approaches are:

- *View A – Use the utility's debt component of its approved weighted average cost of capital*

The approved weighted average cost of capital includes a debt and equity component. The carrying charges applied to the regulatory assets should be calculated based on the debt component of this regulator-approved rate. Proponents of this view believe it represents the debt cost rate approved by regulators, and therefore represents the amount of carrying charges that are recoverable from ratepayers.

- *View B – Use the utility's actual weighted average cost of debt rate*

The carrying charges applied to the regulatory assets should be based on the regulated utility's actual weighted average cost of debt. They prefer to use the actual average cost of debt as opposed to a derivation from the WACC because of ASC 980's prohibition against recognition of shareholder return (because it is not an incurred cost).

- *View C – Use the utility's incremental borrowing rate*

The carrying charges applied to the regulatory assets should be calculated based on the regulated utility's incremental borrowing rate if this methodology is reflective of the utility's actual facts and circumstances. Proponents of this view believe that a regulated utility's regulatory assets are financed with the "last dollar" received (i.e., the regulated utility does not issue equity or debt specifically for the purpose of financing regulatory assets; instead, any required funds are obtained through incremental borrowing).

17.3.1.2 Recovery of the incurred cost is probable

In evaluating whether an incurred cost is eligible for deferral as a regulatory asset, a regulated utility should determine whether the cost is probable of being recovered through future revenue from rates that the regulator allows to be charged to customers.

ASC 980-340-25-1(a)

It is probable (as defined in Topic 450) that future revenue in an amount at least equal to the capitalized cost will result from inclusion of that cost in allowable costs for rate-making purposes.

Determining whether rate recovery of an incurred cost is probable is a matter of judgment and management should evaluate the preponderance and quality of all evidence available. Different forms of evidence will provide varying degrees of support for management's assertion that a regulatory asset is probable of recovery; not all forms of evidence will be sufficient in isolation or in combination to make such an assertion. A specific rate order specifying the nature of the cost and the timing and manner of recovery generally provides the best evidence that recovery is probable. However, the nature of the regulatory process does not always allow a utility to obtain a rate order prior to issuing its financial statements.

Forms of evidence that may support the recognition of a regulatory asset include:

- The regulated utility receives a rate order specifying that the costs will be recovered in the future.
- The incurred cost has been treated by the regulated utility's regulator as an allowable cost of service item in prior regulatory filings.
- The incurred cost has been treated as an allowable cost by the same regulator in connection with another entity's filing.
- It is the regulator's general policy to allow recovery of the incurred cost.
- The regulated utility has had discussions with the regulator (as well as its primary intervenor groups) with respect to recovery of the specific incurred cost and has received assurances that the incurred cost will be treated as an allowable cost (and not challenged) for regulatory purposes.
- A majority of other regulators have treated the specific incurred cost (or similar incurred cost) as an allowable cost and the regulated utility's regulator has not specifically disallowed it.
- The regulated utility has obtained an opinion from outside legal counsel outlining the basis for the incurred cost being probable of being allowed in future rates.

Prior to concluding that recognition of a regulatory asset is appropriate, a regulated utility should also consider other relevant factors, such as:

- The regulatory principles and precedents established by law
- The political and regulatory environment of the jurisdiction (e.g., does further regulation occur in the courts)
- The magnitude of the incurred costs to be deferred and the related impact on ratepayers if such costs are allowed (taking into account the length of the recovery period)
- Whether ratepayers or others may intervene in an attempt to deny recovery

Some regulated utilities have costs that may benefit customers in several jurisdictions. Because recovery is based on a regulator's action, the regulated utility should separately consider the probability of recovery in each regulatory jurisdiction. If it cannot support regulatory recovery across all jurisdictions due to different rate structures or differing fact patterns, the regulated utility should establish a regulatory asset only for those amounts attributable to jurisdictions that meet the criteria for deferral.

Question 17-6

Does an accounting order (without a rate order) provide sufficient support for recognition of a regulatory asset or liability?

PwC response

It depends. An accounting order is an order by a regulatory authority on the accounting treatment for transactions in ratemaking and regulatory reporting. Generally, an accounting order alone will not provide sufficient evidence to support the recognition of a regulatory asset.

The best evidence for a regulatory asset is a rate order, but the timing of the regulatory process sometimes does not enable the regulated utility to obtain one prior to issuing its financial statements. Establishing probability of recovery is more difficult absent a rate order, especially when evaluating unusual or nonrecurring costs.

If a regulated utility obtains an accounting order, it should assess whether a cause and effect relationship is achieved. An accounting order along with supporting evidence, such as historical precedence or an opinion from rate counsel, may provide adequate support for establishment of a regulatory asset if it supports that recovery of the specific cost in the future is probable. Reporting entities should exercise caution when placing reliance on accounting orders. An accounting order to amortize a regulatory asset or other cost with no impact on revenues does not provide the cause and effect relationship between costs and revenues required to create a regulatory asset. Similarly, an accounting order that indicates the costs may be deferred for consideration in a future rate case, with no assurance of recovery, does not provide sufficient evidence that future recovery is probable.

17.3.1.3 Recovery of previously-incurred costs

When an incurred cost is evaluated for potential deferral, one of the key considerations is whether the regulators will approve future revenue to recover the past costs.

ASC 980-340-25-1(b)

Based on available evidence, the future revenue will be provided to permit recovery of the previously incurred cost rather than to provide for expected levels of similar future costs. If the revenue will be provided through an automatic rate-adjustment clause, this criterion requires that the regulator's intent clearly be to permit recovery of the previously incurred cost.

A rate increase intended to recover future costs would not support deferral. Determining whether future revenue will be provided for recovery of previously-incurred costs may require significant judgment. Factors to consider in assessing whether this criterion is met include:

- *State regulatory history*

What is the history of recovery of regulatory assets in the state? Have amounts been disallowed in the past? Is the regulator approving current rates at a level to recover current costs? If not, what evidence supports that the regulator will authorize recovery within a reasonable time period?

- *Projected costs*

Are the regulated utility's costs expected to continue to increase? If costs continue to increase, is it probable that the regulator will be willing to approve sufficient rate increases to recover these past costs as well as current costs?

In particular, the regulated utility should consider whether there is a pattern of increasing costs and deferral of recovery to future periods. This may suggest that it will be difficult to recover the previously-incurred costs through future rates, absent a rate order that specifies recovery.

17.3.2 Subsequent measurement

Subsequent actions of a regulator can either reduce or eliminate the value of a previously-recognized regulatory asset or, alternatively, may provide sufficient support for recognition of amounts previously expensed. Regulated utilities should reassess the probability of a recovery each reporting period, considering the impact of any changes or events during the period.

17.3.2.1 Subsequently-allowed recovery

An incurred cost that does not meet the recognition criteria in ASC 980-340-25-1 at the date the cost is incurred should be recognized as a regulatory asset if and when it meets those criteria at a later date.

ASC 980-340-35-2

If a regulator allows recovery through rates of costs previously excluded from allowable costs, that action shall result in recognition of a new asset. The classification of that asset shall be consistent with the classification that would have resulted had those costs been initially included in allowable costs.

ASC 980-340-35-2 requires that a new asset be recorded for the amount that becomes allowed. Prior to the Codification, FASB Statement No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, paragraph B61 provided further guidance on the classification of the new asset.

Excerpt from FAS 144, paragraph B61

The Board decided that previously disallowed costs that are subsequently allowed by a regulator should be recorded as an asset, consistent with the classification that would have resulted had those costs initially been included in allowable costs. Thus, plant costs subsequently allowed should be classified as plant assets, whereas other costs (expenses) subsequently allowed should be classified as regulatory assets. . . . The Board decided to restore the original classification because there is no economic change to the asset—it is as if the regulator never had disallowed the cost. The Board determined that restoration of cost is allowed for rate-regulated enterprises in this situation, in contrast to other impairment situations, because the event requiring recognition of the impairment resulted from actions of an independent party and not management’s own judgment or determination of recoverability.

Consistent with this guidance, if a reporting entity determines that recovery of an incurred cost is now probable, it should record a new regulatory asset, unless the amount relates to a disallowance of utility plant. The regulated utility should classify plant costs that are initially disallowed and for which the regulator subsequently provides recovery as part of utility plant when the costs are restored. See UP 18.7.3 for further information on the subsequent recovery of plant disallowances and impairments.

17.3.2.2 Impairment of existing regulatory assets

A regulated utility should charge a regulatory asset to earnings if it no longer meets the criteria for recognition in ASC 980-340-25-1.

ASC 980-340-40-1

If at any time an entity’s incurred cost no longer meets the criteria for capitalization of an incurred cost (see paragraph 980-340-25-1), that cost shall be charged to earnings.

Impairment of a regulatory asset may occur due to (1) a change in the reporting entity’s assessment of the probability of recovery or (2) actions of the regulator. ASC 980-340-35-1 requires that if a regulator later excludes from allowable costs all or a

part of a cost that was capitalized as a regulatory asset, the regulated utility should reduce the carrying amount of the regulatory asset by the excluded cost.

Question 17-7

Is it appropriate to recognize a regulatory asset pertaining to a disallowed cost that the utility is litigating?

PwC response

Generally, no. The ratemaking process can span many months and include recommendations by public service commission staff, consumer advocates and other interveners, administrative law judges, and the commissioners themselves. In some cases, requests for reconsideration or court appeals routinely follow final rate orders. At other times, there are stipulated settlements for which it is impossible to track the exact determination of a particular element of the rate setting process. Precisely where in this spectrum a regulatory asset may cease to be or become probable of recovery is a matter of facts and circumstances requiring judgment. Given the uncertain outcome of litigation of final rate orders, it would be rare for costs subject to an unfavorable decision in a rate order, and for which a regulated utility intends to pursue recovery through the courts, to meet the current probable recovery tests necessary for deferral.

17.3.3 *Specific considerations for certain types of regulatory assets*

The utility should evaluate the recognition and measurement of regulatory assets within the framework described in 17.3.1 and 17.3.2 and by incorporating a regulated utility's facts and circumstances. However, there are specific considerations for certain types of regulatory assets related to alternative revenue programs, pension and other postemployment benefit plans and debt.

17.3.3.1 *Alternative revenue programs*

In addition to traditional billing based on cost-of-service revenue, the evolution of regulatory mechanisms (e.g., formula rates, trackers) have led regulators to authorize alternative revenue programs, as defined in ASC 980-605.¹ Figure 17-4 summarizes considerations in the evaluation of alternative revenue programs.

¹ This guidance will not be superseded by the new revenue standard codified in ASC 606.

Figure 17-4
Alternative revenue program considerations

Indicators that a mechanism represents an alternative revenue program	Indicators that a mechanism does <u>not</u> represent an alternative revenue program
<ul style="list-style-type: none"> □ Purpose is to authorize additional revenues in specified circumstances □ Nature of the program is consistent with the description of an alternative revenue program described in ASC 980-605 <ul style="list-style-type: none"> ○ Incremental revenue to be recognized is driven by factors outside the regulated entity's control (e.g., weather), or as a result of the achievement of certain objectives (e.g., reduction of sales through demand side management programs or achieving customer service targets) □ All three criteria in ASC 980-605-25-4 are explicitly met 	<ul style="list-style-type: none"> □ Purpose is to provide timely recovery of a cost of service (or changes to cost of service) □ Nature of the program is inconsistent with the description of an alternative revenue program <ul style="list-style-type: none"> ○ Structured to address rate lag and/or items included (or to be included) in rate base □ Costs incurred (and to be recovered) represent costs controlled by the regulated entity □ There is uncertainty as it relates to one or more of the three criteria in ASC 980-605-25-4
Example of a program that qualifies as an alternative revenue program	Example of a program that does not qualify as an alternative revenue program
<p><i>Decoupling mechanism</i></p> <p>Purpose of the program is to make the regulated utility whole from a revenue perspective by entitling the utility to incremental billings intended to compensate it for lost sales volume (resulting from its pursuit of energy efficiency goals or driven by weather volatility).</p>	<p><i>Capital improvement program</i></p> <p>Purpose of the program is to enable a regulated utility to accelerate recovery of capital spending in between rate cases by immediately (or within a short period of time) including the utility plant in rates once the asset is placed into service. The program allows cost recovery plus a return, consistent with a regulated utility's normal return on rate base. The program also makes the regulated utility whole for any shortfalls in recovery of costs due to rate lag.</p>

Improper characterization of a regulatory mechanism established by regulators as an alternative revenue program could lead to accelerated revenue and/or the premature recognition of shareholder return. Regulated utilities with alternative revenue programs are permitted to recognize a regulatory asset for the full weighted-average cost of capital, including debt and equity components, while regulated utilities with other regulatory assets may only defer the debt portion, which is deemed an incurred cost. Therefore, it is important to evaluate the nature and purpose of each regulatory mechanism and assess whether the substance of the program is, in fact, an alternative revenue program. To do so, the regulated utility should perform two steps.

Step one

When analyzing whether a particular program meets the criteria to qualify as an alternative revenue program, a regulated utility should begin by assessing the program's purpose. Programs that are consistent with the core principle of traditional regulatory accounting regarding the timing of collection of an incurred cost may not qualify as an alternative revenue program. We believe this is evident based on the language in ASC 980, which distinguishes between two different types of revenue.

ASC 980-605-25-1

Traditionally, regulated utilities whose rates are determined based on cost of service invoice their customers by applying approved base rates (designed to recover the utility's allowable costs including a return on shareholders' investment) to usage. Some regulators of utilities have also authorized the use of additional, alternative revenue programs. The major alternative revenue programs currently used can generally be segregated into two categories, Type A and Type B. [Emphasis added]

ASC 980-605-25-2 describes Type A and Type B programs and lists examples of each type. The programs that qualify for each are intended to be incremental to the utility's base rates or a change to the pace of collection based on sales volume. These programs are not designed to be for the recovery of allowable costs including a return. We believe that qualifying programs should be additions to revenue/billings, which usually are not cost-driven (i.e., the program should not be a cost recovery mechanism or a cost tracker). The billings should be driven by broad external factors, such as changes in customer behavior that leads to changes in the demand for the commodity (Type A program) or incentive awards that are incremental to cost recovery (Type B program).

□ *Type A*

These are rate normalization plans that adjust billings for the effects of weather abnormalities, broad external factors, or to compensate the regulated utility for demand-side management initiatives. For example, many states have rate decoupling programs in place that provide the regulated utility with the right to a fixed amount of revenue for the year or a fixed amount per customer, irrespective of usage (or some variation), to address fluctuations in revenue due to weather or consumption.

□ *Type B*

These are incentive programs that provide for additional billings (incentive awards) if the regulated utility achieves certain objectives, such as reducing costs, reaching specified milestones, or improving customer service.

Both types of programs enable regulated utilities to adjust rates in the future (usually as a surcharge applied to future billings) in response to past activities or completed events. These programs can reduce volatility in earnings (important to regulated utilities and their investors) and rates (important to ratepayers) and can be tailored to accommodate specific objectives.

Depending on the program, the amounts to be collected may cover a portion of the regulated utility's cost of service. In such circumstances, a question arises as to whether it is appropriate to recognize a regulatory asset for incurred costs pursuant to the general guidance on regulatory assets under ASC 980. Because Type B programs are typically incentive programs not intended to recover cost of service, recognition of a regulatory asset under the general guidance of ASC 980 with respect to this type of program generally would not be appropriate. Programs that create incremental revenue for a utility and fall under a Type A or Type B program would qualify for accounting as an alternative revenue program, assuming the other criteria in paragraph 980-605-25-4 are met.

The programs must qualify as Type A or Type B before proceeding to Step two.

Step two

Once deemed to be a qualifying program, a utility should evaluate the program against the three criteria in ASC 980-606-24-4. We do not believe that a program qualifies as an alternative revenue program by simply meeting those criteria. Programs often appear to be "alternative" if they are negotiated on a standalone basis outside of a full rate case. Many of these programs allow for an automatic rate adjustment, are probable of recovery, and are collected within 24 months of when the cost was incurred or allowed. However, this factor alone is not sufficient to be within the scope of the alternative revenue program guidance as the program must first qualify as a Type A or Type B program (as defined in ASC 980-605-25-2).

ASC 980-605-25-1 through 25-4 address the accounting for these programs and provide for current recognition of revenue under certain limited circumstances.

ASC 980-605-25-4

Once the specific events permitting billing of the additional revenues under Type A and Type B programs have been completed, the regulated utility shall recognize the additional revenues if all of the following conditions are met:

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

- b. The amount of additional revenues for the period is objectively determinable and is probable of recovery.
- c. The additional revenues *will be collected* within 24 months following the end of the annual period in which they are recognized. [Emphasis added]

These conditions establish a high threshold to recognize revenue prior to billing and collecting amounts from customers. Due to the specificity of the guidance, a program must comply with all of the criteria to permit revenue recognition. For example, we believe recognition by a regulated utility would be precluded if it does not have a specific rate order providing for the alternative revenue program. An assessment that it is probable the regulator will adopt an alternative revenue program based on historical practice would not be sufficient to support recognition.

Similarly, a regulated utility should assess the amount of revenue to be collected under a program and the collection period in concluding on the appropriateness of revenue recognition. The condition for recognition indicates that “revenues will be collected.” If there is any uncertainty about whether the amounts will be collected, this criterion would not be met.

Question 17-8

ASC 980-605-25-4(c) requires collection of the additional revenue within 24 months following the end of the annual period in which the revenue is recognized. What is the impact on recognition if collections extend beyond those 24 months?

PwC response

In some cases, an alternative revenue program may explicitly provide for the collection of revenues over a period that extends beyond 24 months following the end of the regulated utility’s fiscal year. Other programs may allow for future collection of amounts that were not initially collected within 24 months.

We believe there are alternative ways to account for the revenue under a regulator-approved alternative revenue program that includes collections extending beyond 24 months after the end of the regulated utility’s fiscal year, but that otherwise meets the recognition criteria in ASC 980-605-25-4. We believe any of these approaches detailed in Figure 17-5 are acceptable when accounting for revenue from an alternative revenue program. The choice of approach is a policy decision that should be consistently applied and disclosed (if material).

Figure 17-5

Summary of approaches to accounting for alternative revenue programs when revenues are collected over a period greater than 24 months

Approach	Recognition	Considerations
All or nothing	<ul style="list-style-type: none"> □ Because all the criteria are not met at inception of the program, revenue is not recognized until billed. 	Supporters of this approach believe that the guidance in ASC 980-605-25 is prescriptive in nature, requiring all of the criteria to be met at the inception of the program. They believe recognition under the alternative revenue guidance is not permitted if any recovery extends beyond the period specified in the guidance. As such, revenue should be recorded as amounts are billed to the customers. This approach may be appropriate when there is uncertainty about the timing of collection.
Partial revenue recognition	<ul style="list-style-type: none"> □ Recognize revenue for amounts that will be collected within 24 months of the end of the annual period. □ Amounts that will be collected beyond 24 months are recognized when billed or when the criteria for alternative revenue programs are met (i.e., when collection will occur within 24 months of the end of the annual period). 	Supporters of this approach believe that the specific collections that occur in the 24-month period meet the criteria for recognition. Amounts to be collected in the third and fourth year would be recognized as billed or, alternatively, when the amounts qualify.

Approach	Recognition	Considerations
Hybrid approach	<ul style="list-style-type: none"> □ Revenue is recognized as billed until all of the criteria for recognition are met (i.e., recognize as billed until the time when all amounts remaining will be collected within 24 months following the end of the annual period). 	<p>Similar to the all or nothing approach, supporters of this view focus on the specific requirements under the guidance in ASC 980-605-25. However, under the hybrid approach, revenue would be recognized once all of the criteria are met, even if that occurs after the program has begun. For example, if under the program, amounts will be collected over four years, amounts would be recognized when billed during the first two years. Amounts to be collected within the third and fourth year would be recognized once they will be collected within 24 months of the fiscal year-end (i.e., at the beginning of the third year).</p>

Question 17-9

How should a regulated utility consider undercollections or other changes in the timing of collections in determining revenue recognition under an alternative revenue program?

PwC response

As described in Question 17-8, there are different acceptable approaches to accounting for an alternative revenue program when collections are expected to occur beyond 24 months. Unless the “all-or-nothing” approach is applied, regulated utilities should closely monitor the potential for “stacking” of undercollections (due to multiple years of decoupling) or extended periods of undercollections. If collections are delayed beyond the original period, regulated utilities should assess whether amounts continue to qualify for recognition. In addition, an extended period of rollover due to lower than anticipated collections may impact a regulated utility’s ability to continue to recognize amounts in the future.

17.3.3.2 Pension and other postemployment benefit plans

ASC 715, *Compensation—Retirement Benefits*, provides guidance on employers’ accounting for defined benefit pension and other postemployment benefit (OPEB) plans, and requires full balance sheet recognition of the funded status of those plans with an offset to accumulated other comprehensive income for any deferred amounts (i.e., unrecognized prior service cost and unrecognized actuarial gains and losses). ASC 715 is applicable to all reporting entities, including regulated utilities. ARM 4270

and ARM 4380 provide information on accounting by employers for defined benefit pension and OPEB plans, respectively.

In accounting for pension and OPEB plans, a regulated utility should consider whether it is appropriate to record a regulatory asset to offset the liability recognized as a result of applying ASC 715 (in lieu of recognizing a charge to other comprehensive income).

Positive factors

Examples of factors to support regulatory offset for pension and OPEB liabilities include:

- Current rate recovery of pension and OPEB costs that is consistent with expense recognition under ASC 715-30 and ASC 715-60 (i.e., ASC 715 costs under U.S. GAAP form the basis for pension and OPEB amounts recovered in rates)
- Existence of a regulatory tracker mechanism or reconciliation process specified in a rate order with comparison of actual annual ASC 715 cost to costs included in rates, with short-term recovery of the difference
- Historical consistency and clarity in the regulator's approach to rate recovery
- No indication of uncertainty or potential changes in the jurisdiction regarding the rate recovery approach to costs consistent with ASC 715-30 and ASC 715-60 combined with general stability in the jurisdiction's approach to traditional cost of service (i.e., there is no existing legislation or substantive discussion to deregulate any aspect of a regulated utility's operations)
- Existence or issuance of a rate order providing that regulatory asset treatment for the unfunded liability is appropriate or required and that recovery of the unfunded costs will be provided in future rates (A rate order provides the best evidence, but consideration may also be given to staff accounting orders and policy statements)

ASC 980-715-25-3 through 25-7 specify additional criteria for recognition of a regulatory asset for OPEB costs, including a satisfactory rate order that allows for recovery of those costs within 20 years, and no backloading of cost recovery on a percentage basis. That guidance also specifically precludes recognition of a regulatory asset if costs are recovered on a pay-as-you-go basis, even if other factors indicate that future recovery of OPEB costs is probable.

ASC 980-715-25-4

For continuing postretirement benefit plans, a regulatory asset related to Subtopic 715-60 costs shall not be recorded if the regulator continues to include other postretirement benefit costs in rates on a pay-as-you-go basis. The application of this Topic requires that a rate-regulated entity's rates be designed to recover the specific entity's costs of providing the regulated service or product. Accordingly, an entity's cost of providing a regulated service or product includes the costs provided for in Subtopic 715-60.

Strong indicators of probable recovery include cost recovery on an accrual basis consistent with U.S. GAAP and the implementation of a tracker mechanism by the regulator. The existence of one of the positive indicators may or may not by itself support a probable recovery conclusion. However, regulated utilities will likely find the existence of more than one of these factors helpful in reaching a conclusion that recording a regulatory asset is appropriate.

Negative factors

In contrast, we believe the following conditions could be viewed as negative factors that may cause management to conclude that recovery of the unfunded pension or OPEB liability is not probable:

- Current rate recovery of pension or OPEB costs on a “pay-as-you-go,” cash funding, Employee Retirement Income Security Act (ERISA) minimum funding, or some other basis
- Previous specific disallowance of either pension or OPEB costs
- Substantive historical inconsistency in the regulator's approach to rate recovery for pension and OPEB costs

The existence of one of the indicators that regulatory treatment might not be appropriate may or may not by itself prevent a regulated utility from concluding that recovery is probable. However, the existence of more than one of these factors will make it difficult to conclude recovery is probable.

Question 17-10

If a plan is settled or curtailed, is specific regulatory action allowing recovery of the cost of the curtailment or settlement necessary to recognize a pension or OPEB-related regulatory asset?

PwC response

No. We do not believe the lack of a specific regulatory action allowing recovery of costs incurred in connection with a pension plan settlement or curtailment accounted for in accordance with ASC 715 will preclude a regulated utility from concluding that the costs are probable of recovery from ratepayers. However, a previous specific

disallowance of a settlement or curtailment may raise a question as to the recoverability of all pension and OPEB costs.

Question 17-11

How should a regulated utility account for a change in the assessment of regulatory recovery of pension and OPEB costs?

PwC response

As discussed in UP 17.3.2.1, an incurred cost that does not initially meet the recognition criteria in ASC 980-340-25-1 should be recognized as a regulatory asset if it meets those criteria at a later date.

If subsequent regulatory actions result in a regulated utility's ability to assert that recovery of pension or OPEB costs is probable, then the regulated utility should first understand the impact of regulatory recovery on the benefit-related amounts recognized in accumulated other comprehensive income. The regulated utility should assess whether all previously-recognized amounts are now probable of recovery through future rates. In addition, the reversal of amounts previously recorded in accumulated other comprehensive income but that are now expected to be recovered through rates should be recognized in other comprehensive income in the current period. This evaluation should also consider whether over-collected amounts would be returned to ratepayers (i.e., creating a regulatory liability).

Question 17-12

Can a parent company record an offsetting regulatory asset if the ASC 715 liability is not recorded in the regulated subsidiary's separate financial statements?

PwC response

Yes, if the criteria for recognition are met. When a parent company has a pension or OPEB plan that covers employees of its regulated and unregulated subsidiaries, ASC 715 indicates that the plan should be accounted for as a single-employer plan in the parent company's consolidated financial statements. If a subsidiary issues separate financial statements and participates in its parent company's plan, the subsidiary, in its separate financial statements, should generally account for its participation in the plan as participation in a multi-employer plan in accordance with ASC 715-30-55-64. This guidance typically results in the subsidiary recording expense based on its required contribution for the period, with recognition of a liability only for contributions that remain unpaid as of the period end (see ARM 4270.3621 for further information).

We believe a parent company can record a regulatory asset in consolidation equal to the regulated subsidiary's unfunded or underfunded liability if the criteria for recognition under ASC 980 are met. The factors the parent considers should follow the analysis that would have been performed if the ASC 715 obligations had been recorded by the subsidiary. Any unfunded or underfunded amounts that do not meet

the regulatory asset criteria as well as liabilities related to the unregulated subsidiaries would be recorded through a charge to other comprehensive income.

17.3.3.3 Debt

Certain costs associated with debt may also be deferred as an asset if they meet the criteria included within ASC 980. Specific considerations related to debt are detailed in ASC 980-450; the items addressed include early extinguishment gains or losses and costs for reacquired debt.

ASC 980-470-40-1

Subtopic 470-50 requires recognition in income of a gain or loss on an early extinguishment of debt in the period in which the debt is extinguished. For rate-making purposes, the difference between the entity's net carrying amount of the extinguished debt and the reacquisition price may be amortized as an adjustment of interest expense over some future period.

Additionally, ASC 980-470-40 indicates that the difference between reacquisition costs and the net carrying costs for reacquired debt should be capitalized as a regulatory asset or recorded as a liability if the regulator decides to increase or decrease future rates by amortizing the difference for rate-making purposes.

Debt issuance costs

Rate-regulated entities are often permitted to recover the costs of issuing debt instruments in rates. If the costs meet the qualification for recognition under ASC 980, as discussed in UP 17.3.1, then the regulated utility should recognize these costs as regulatory assets rather than as a direct deduction to the face value of the note, as prescribed in ASC 835-30-45-1A.

17.4 Regulatory liabilities

ASC 980-405-25-1 provides specific criteria for recognition of three types of regulatory liabilities that may arise as a result of actions of a regulator:

- Refunds of amounts previously collected from customers (UP 17.4.1)
- Current collections for future expected costs (UP 17.4.2)
- Refunds of gains (UP 17.4.3)

These liabilities are a regulated utility's obligations to its customers. Recognition and measurement of the three general types of regulatory liabilities is further discussed in this section.

Question 17-13

Should a regulated utility recognize liabilities required under U.S. GAAP for entities in general?

PwC response

Yes. A regulated utility may be eligible for rate recovery of amounts that are recorded as a liability under U.S. GAAP (e.g., incurred but not reported personal injury claims, environmental liabilities). Regulated utilities may question whether such liabilities should be recorded in the financial statements. Liabilities that are recorded pursuant to U.S. GAAP in general are not within the scope of ASC 980-405-25-1 because they are not created or imposed by the actions of the regulator. Therefore, the requirement to recognize such liabilities does not depend on whether the regulator has provided recovery of the costs relating to such liabilities.

ASC 980-405-40-1 specifically indicates that a regulator can only eliminate a liability that was previously imposed by its actions. Therefore, in addition to potential regulatory liabilities, regulated utilities should record all liabilities that would be recorded by entities in general. If the liability will be recoverable through rates, the regulated utility may be able to record a regulatory asset, assuming the criteria in ASC 980-340-25 are met.

Question 17-14

How should a regulated utility account for future rate reductions?

PwC response

A regulator may require that a regulated utility reduce customers' rates in future periods that do not relate to existing conditions. For example, a regulated utility may be required to provide future rate concessions as part of a general rate case or may reduce future rates in the form of credits that are agreed to in connection with a business combination (merger credits) or a FERC license renewal. The regulated utility should not accrue the effects of regulator-ordered future rate reductions in advance, but should recognize them as reduced revenue in future periods. Such future obligations do not meet the general definition of a liability under Statement of Financial Accounting Concept 6: *Elements of financial statements* (CON 6).

CON 6, paragraph 35

Liabilities are probable future sacrifices of economic benefits arising from present obligations of a particular entity to transfer assets or provide services to other entities in the future as a result of past transactions or events.

Future rate reductions do not represent an obligation to transfer assets (i.e., no cash consideration will be transferred) nor an order by a regulator to refund amounts previously collected from customers. Rather, they represent a requirement to accept a reduced return on future sales (whether provided directly through a rate credit or

through a reduction of costs allowed in establishing future rates). There is also no obligation to provide future service outside of what would otherwise be provided in the normal course of business. Therefore, the CON 6 criteria are not met and no liability should be recorded under U.S. GAAP applied by entities in general.

Some may view the agreement to provide future rate reductions as an onerous contract or agreement with the regulator because the regulated utility is agreeing to provide service in the future at reduced rates. However, even if this agreement is viewed as a contractual commitment, the regulated utility should not recognize a liability for expected losses on executory contracts prior to those losses being incurred, unless specifically permitted in authoritative guidance.

Furthermore, as summarized in Figure 17-6, future rate concessions typically do not meet the definition of a regulatory liability.

Figure 17-6
Are future rate reductions regulatory liabilities?

Guidance	Evaluation	
ASC 980-405-25-1(a)	A regulator may require refunds to customers. . . . Refunds that meet the criteria of. . . loss contingencies (see ASC 450-20-25-2) shall be recorded as liabilities. (UP 17.4.1)	ASC 450-20-25-2 requires accrual of a loss contingency if it is both probable that a liability has been incurred and the liability is reasonably estimable. Future rate reductions do not meet the definition of a liability; therefore, no regulatory liability should be recorded.
ASC 980-405-25-1(b)	A regulator can provide current rates intended to recover costs that are expected to be incurred in the future with the understanding that if those costs are not incurred future rates will be reduced by corresponding amounts. (UP 17.4.2)	Not applicable. Rate reductions due to merger credits or rate concessions are not imposed due to costs previously incurred. Contractual obligations related to merger settlements should be evaluated as liabilities under ASC 450.
ASC 980-405-25-1(c)	A regulator can require that a gain or other reduction of net allowable costs be given to customers over future periods. (UP 17.4.3)	Not applicable if future rate reductions do not represent the return of prior gains nor net allowable costs to customers over future periods.

Amounts should not be recognized in connection with a commitment to provide future rate reductions until the rate reductions occur, consistent with the guidance for commitments.

17.4.1 Refunds of previous customer collections

ASC 980 includes guidance that applies to any regulator-imposed refund of amounts previously collected from customers. Typical examples of these types of regulatory liabilities include:

- Revenue billed subject to refund
- Excess collections of allowable costs included in rates that were lower than anticipated (e.g., balancing accounts)

Regulated utilities should evaluate potential regulatory liabilities associated with refunds to customers of previously-collected amounts in accordance with the guidance for loss contingencies in ASC 450-20-25-2. They should recognize a liability if it is probable that the loss was incurred at the balance sheet date and the loss is reasonably estimable. Specific considerations with respect to certain types of refunds are further discussed in the following sections.

17.4.1.1 Revenue subject to refund

Regulators may allow a regulated utility to begin billing requested revenue increases in advance of a ruling on the request. Although the regulator authorizes the regulated utility to bill its customers, the regulated utility and the regulator both understand that the authority to bill does not represent approval of the rates. A subsequent ruling by the regulator may result in the regulated utility having to refund all or certain amounts billed in advance.

Revenues collected subject to refund may be substantial in amount; regulated utilities will need to apply judgment to determine the appropriate recognition.

The regulated utility should determine any regulatory liability based on its best estimate of a probable loss, consistent with the guidance in ASC 450-20-25-2. Before recognizing revenue subject to refund, regulated utilities should consider actions taken in past cases in the regulatory jurisdiction, opinion of legal counsel, and other factors. See UP 21 for information on disclosure requirements for revenue subject to refund.

Question 17-15

How do you recognize revenue subject to refund when there is a wide range of potential outcomes?

PwC response

If a regulated utility believes it is probable that some amount of refund will be required, but the range of potential refunds is so wide that it is difficult to estimate, it

may be difficult to support the recognition of revenue prior to the approving rate order.

Excerpt from ASC 980-605-30-2

If the range of possible refund is wide and the amount of the refund cannot be reasonably estimated, there may be a question about whether it would be misleading to recognize the provisional revenue increase as income.

Consistent with this guidance, if a regulated utility is unable to reliably estimate the amount of potential refund, it should defer recognition of any amounts collected that are subject to refund.

Timing of recognition

In general, reporting entities should recognize amounts previously deferred or reverse revenue previously recognized (i.e., if it becomes probable that a refund will be required) in the period the order is received or the probability assessment changes. However, there is an exception to this general rule for certain rate impacts that occur in interim periods.

ASC 250-10-45-25 through 45-26 require restatement of prior interim periods of a current fiscal year for certain types of income statement adjustments that meet specified criteria. This guidance is referenced by ASC 980-250-55-4 through 55-5 in the context of refunds to customers. In accordance with this guidance, a reporting entity should restate prior interim periods for revenue subject to refund if all of the following criteria are met:

Excerpt from ASC 250-10-45-25

- a. The effect of the adjustment or settlement is material in relation to income from continuing operations of the current fiscal year or in relation to the trend of income from continuing operations or is material by other appropriate criteria.
- b. All or part of the adjustment or settlement can be specifically identified with and is directly related to business activities of specific prior interim periods of the current fiscal year.
- c. The amount of the adjustment or settlement could not be reasonably estimated prior to the current interim period but becomes reasonably estimable in the current interim period.

ASC 250-10-45-25 goes on to state that the receipt of a final rate order would result in criterion (c) being met. Therefore, if a regulated utility receives a final rate order related to revenue subject to refund that was previously billed and the order impacts rates of a prior interim period, the regulated utility will need to consider the appropriate period in which to record any adjustment to amounts previously

recognized. Figure 17-7 summarizes the financial statement impact if all of the criteria are met.

Figure 17-7
Accounting for adjustments resulting from a rate-order

Period to which settlement applies	Period impacted
Prior fiscal year(s)	Restate the first interim period of the current fiscal year to include the amounts
Prior interim periods of current fiscal year	Restate the applicable interim periods of the current fiscal year to include the amounts
Current interim period	Record in current interim period

In determining whether to adjust the prior period statements, the reporting entity should consider whether the order relates to revenue subject to refund and, if so, whether all of the other criteria in ASC 250-10-45-25 are met.

Question 17-16

Does the guidance on restatement of prior interim periods apply to adjustments other than revenue subject to refund (e.g., a rate increase)?

PwC response

No. We believe application of this guidance should be limited to situations involving changes to amounts previously-recognized when a regulated utility has billed revenue subject to refund and should not be applied more broadly. ASC 980-250 discusses the interim guidance only in the context of customer refunds.

The question of whether the guidance on interim period adjustments applies to any type of rate adjustment stems from the ASC 250-10-45-25 reference to “utility revenue under ratemaking processes” in discussing situations when the guidance applies.

17.4.1.2 Balancing accounts

Some forms of regulatory mechanisms result in balances that change from being a regulatory asset to a regulatory liability from period to period, and vice versa. This typically occurs due to over- and under-collections of billings as compared to actual costs incurred. Common examples include natural gas balancing accounts, alternative revenue arrangements, pension amounts, and gains/losses (realized and unrealized) that are passed on to ratepayers as reductions or increases in rates, respectively. In those cases, reporting entities should evaluate the guidance that applies to regulatory assets or regulatory liabilities depending on whether the balance is an asset or liability. These types of regulatory accounts are discussed in UP 17.3.

17.4.2 ***Current collections for future expected costs***

A regulatory liability arises when a regulator provides current rates intended to recover costs that are expected to be incurred in the future, with an understanding that future rates will be reduced if those costs are not incurred.

A regulated utility should record a regulatory liability (instead of revenue) for amounts collected in advance of the related expenditures, if it is required to refund any amounts not expended. Amounts recorded as a regulatory liability would be recognized in income when the associated costs are incurred.

Excerpt from ASC 980-405-25-1(b)

A regulator can provide current rates intended to recover costs that are expected to be incurred in the future with the understanding that if those costs are not incurred future rates will be reduced by corresponding amounts. If current rates are intended to recover such costs and the regulator requires the entity to remain accountable for any amounts charged pursuant to such rates and not yet expended for the intended purpose, the entity shall not recognize as revenues amounts charged pursuant to such rates. The usual mechanism used by regulators for this purpose is to require the regulated entity to record the anticipated cost as a liability in its regulatory accounting records. Those amounts shall be recognized as liabilities and taken to income only when the associated costs are incurred.

Some common items that may be subject to this type of tracking mechanism include storm costs, environmental costs, or other contingent expenditures. For example, a regulator may provide recovery in current rates for a future contingency that would otherwise not meet the definition of a liability under ASC 450. In this situation, the regulated utility is typically required to track such amounts and refund customers to the extent of any unused collections.

17.4.2.1 ***Application example — evaluating current collections for future expected costs***

Example 17-1 illustrates considerations in evaluating the accounting for amounts collected in advance of being incurred.

EXAMPLE 17-1

Accounting for storm costs included in base rates

Rosemary Electric & Gas Company (REG), a regulated utility subject to ASC 980, operates in a region where major storms are a common occurrence. To ensure sufficient and timely cash flows to quickly make needed repairs resulting from storms, the regulator allows REG to collect \$50 million each year for contingent storm costs. However, the regulator requires that any amounts not spent in a given year be returned to customers in the subsequent year.

Should REG record a regulatory liability for amounts collected until storm costs meeting the specified criteria are incurred?

Analysis

Yes. Because REG is required to track associated costs and return unused amounts to customers, REG should record a regulatory liability for amounts collected until storm costs meeting the specified criteria are incurred. If REG experiences qualifying storm costs during the year, it would recognize the costs in the income statement when incurred, with a corresponding reduction to the liability and increase in revenues.

17.4.3 Refunds of gains

Regulators may require a regulated utility to partially or wholly share gains with its ratepayers. Common examples of such gains may include amounts arising from the sale of utility property, debt extinguishments, or investment income associated with debt and equity securities (including amounts earned from investments such as nuclear decommissioning trust funds). Such gains are typically provided to ratepayers over a period of time in the form of reduced rates.

ASC 980-405-25-1(c) requires deferred gains that will be returned as a regulatory liability to be amortized over the period that rates are reduced. In evaluating whether to recognize a gain, a regulated utility will need to evaluate whether it is probable that some or all of the gain will be returned to ratepayers.

ASC 980-405-25-1(c)

A regulator can require that a gain or other reduction of net allowable costs be given to customers over future periods. That would be accomplished, for rate-making purposes, by amortizing the gain or other reduction of net allowable costs over those future periods and reducing rates to reduce revenues in approximately the amount of the amortization. If a gain or other reduction of net allowable costs is to be amortized over future periods for rate-making purposes, the regulated entity shall not recognize that gain or other reduction of net allowable costs in income of the current period. Instead, it shall record it as a liability for future reductions of charges to customers that are expected to result.

17.4.3.1 Application example — accounting for gains to be refunded

Example 17-2 illustrates considerations in evaluating the accounting for a gain to be returned to customers.

EXAMPLE 17-2**Accounting for a gain on sale of land**

Rosemary Electric & Gas Company (REG) sells excess land with a carrying value of \$25 million for \$40 million. The land was originally purchased by REG to construct an operations center; instead, REG ultimately agreed with its regulator that it would build two operations centers at other locations. The cost of construction will be included in rate base. At the time of the sale, the regulator approves the transaction but does not determine the required treatment of the gain (i.e., whether REG's

shareholders will retain the gain or whether the gain will be partially or wholly returned to customers). That determination is expected to be made in the next general rate case. However, for prior property sales, REG has been required to return between 75-100 percent of any gains to its ratepayers.

Should REG defer the gain and record a regulatory liability?

Analysis

Yes. Because of its history involving similar transactions and the expectation that the new land acquired to construct the operations centers will be included in rate base, REG determines that it is probable that all of the gain will be used to reduce future rates to customers. As a result, REG defers the gain and records a regulatory liability.

17.4.4 Subsequent accounting

Regulatory liabilities may be settled in a variety of ways. Liabilities may be refunded to customers, offset against regulatory assets in a rate case, or taken to income when costs associated with a liability for recovery of future costs are incurred. Additionally, actions of a regulator can eliminate a liability provided that the liability was imposed by the actions of the regulator. ASC 980 indicates when regulatory liabilities should be recognized in income and cross-references to ASC 225-10-S99-2 for general considerations regarding appropriate income presentation, but does not specify where within the income statement the amortization of a regulatory liability should be recorded.

A regulated utility may present the amortization of specific regulatory liabilities as a separate line item, a reduction to revenue, or within related expense accounts. However, a regulated utility should present the amortization of similar regulatory liabilities consistently within the income statement and from period to period.

17.5 Subsequent events

Due to the nature of the regulatory process, a reporting entity may receive additional information from its regulator or a final regulatory decision after the end of a reporting period but prior to releasing its financial statements. In those situations, a question arises as to whether the impact of the information or decision should be recorded in the prior period or the period in which it was received. ASC 855, *Subsequent Events*, provides guidance on the timing of recognition of subsequent events.

Excerpt from ASC 855-10-25-1

An entity shall recognize in the financial statements the effects of all subsequent events that provide additional evidence about conditions that existed at the date of the balance sheet, including the estimates inherent in the process of preparing financial statements.

The type of subsequent event described in ASC 855-10-25-1 is commonly referred to as a “Type I” subsequent event. In contrast, “Type II” subsequent events provide information about events that did not exist at the balance sheet date and should not be recognized until they occur.

There are two views about the appropriate accounting for regulatory information or decisions received after the balance sheet date. Some argue that any information or decision necessarily relates to conditions that existed at the balance sheet date (except in limited circumstances when the order addresses a specific event that occurred after the balance sheet date). However, others believe that a regulatory decision should be treated as a discrete event and recognized in the period received. We believe that both views are acceptable. A regulated utility should elect a policy with regard to the accounting for regulatory information or decision received after the balance sheet date and the policy should be consistently applied and disclosed (if material).

17.6 Accounting changes

Regulated utilities are subject to the guidance on accounting changes for entities in general (which are addressed in FSP 30). If a regulated utility adopts an accounting change that does not affect allowable costs for ratemaking purposes, ASC 980-250-55-3 requires that the change be applied in the same manner as an unregulated entity.

In some cases, a new U.S. GAAP requirement results in recording a balance that is being collected through rates and would be eligible for regulatory accounting. For example, in 2007, reporting entities were required to apply new guidance that resulted in recording the unfunded or underfunded pension and OPEB liability. Under the prior accounting model, these amounts had not been recorded on the balance sheet. In that situation, many regulated utilities were able to conclude that it was appropriate to offset the new liability with a regulatory asset instead of a charge to other comprehensive income (see UP 17.3.3.2 for further information).

When adopting a new accounting standard, regulated utilities should evaluate the specific facts and circumstances, including the cost recovery model and applicability of regulatory accounting, in determining whether it is appropriate to record new regulatory assets or liabilities.

17.7 Intercompany profit

ASC 980-810-45 requires that in certain circumstances intercompany profit on sales from unregulated entities to regulated affiliates should not be eliminated in the general purpose financial statements. This would be the case if both of the following conditions exist:

- The sales price charged to the regulated utility by the unregulated affiliate is reasonable.
- It is probable that future revenues allowed in the ratemaking process will provide for the recovery of the sales price resulting from the regulated utility’s use of the product(s).

When evaluating whether the sales price is reasonable, reporting entities should consider whether the price is accepted by the regulator or otherwise not challenged. Alternatively, the regulated utility should consider comparison to the return or pricing from other available sources.

This guidance is restricted to sales to the regulated affiliate by its unregulated affiliate. Intercompany profit on sales from a regulated utility to an unregulated affiliate should be eliminated in consolidation.

17.8 Discontinuation of rate-regulated accounting

Certain changes to the regulatory or competitive environment in which a regulated utility operates may result in the regulated utility no longer qualifying for application of ASC 980 to all or certain portions of its operations. Whether and when a regulated utility no longer meets the criteria for application of rate-regulated accounting for all or a portion of its operations is highly judgmental. See UP 17.2 for further information on factors that support continued application of ASC 980 as well as indicators that ASC 980 may no longer be applicable. Furthermore, ASC 980-20 includes examples of factors that may lead to the conclusion that a regulated utility fails to meet the criteria in ASC 980-10-15-2.

ASC 980-20-15-2

Failure of an entity's operations to continue to meet the criteria in paragraph 980-10-15-2 can result from different causes. Examples include the following:

- a. Deregulation
- b. A change in the regulator's approach to setting rates from cost-based rate-making to another form of regulation
- c. Increasing competition that limits the entity's ability to sell utility services or products at rates that will recover costs (as used in paragraph 980-10-15-2)
- d. Regulatory actions resulting from resistance to rate increases that limit the entity's ability to sell utility services or products at rates that will recover costs if the entity is unable to obtain (or chooses not to seek) relief from prior regulatory actions through appeals to the regulator or the courts.

17.8.1 Partial discontinuation

Discontinuation of application of ASC 980 may apply to all or part of a regulated utility's operations. ASC 980-20 specifically indicates that discontinuation of ASC 980 should apply to a separable portion of a regulated utility's operations that no longer meets the application criteria (i.e., partial discontinuation). Examples of a separable portion of the business include:

- All operations within a regulatory jurisdiction

- An operating asset
- A customer class
- A functional activity, such as generation

ASC 980-20-40-1 also indicates that the discontinuation of ASC 980 for a separable portion of a reporting entity's operations within a jurisdiction creates a presumption that discontinuation of ASC 980 should apply to the entire jurisdiction. That presumption can be overcome by demonstrating that the reporting entity's other operations within the jurisdiction continue to meet the criteria in ASC 980-10-15-2. See Question 17-2 for further information on whether a group of costs would represent a separable portion of the business.

17.8.2 *Timing of discontinuation*

It may be difficult to determine the point in time when a regulated utility no longer qualifies to apply ASC 980 because the factors that impact its application may change gradually. For example, deregulation initiatives as well as changes in the ratemaking process, the competitive landscape, and customer demand may occur over several reporting periods. As a result, determining whether, and when, a regulated utility should discontinue applying ASC 980 requires judgment and monitoring of the regulatory, legal, and competitive factors described in UP 17.2.2 and UP 17.2.3. One negative factor on its own would not necessarily lead to a determination that ASC 980 should be discontinued; however, regulated utilities should weigh the nature and pervasiveness of any factors that are present and assess the preponderance of evidence in reaching a conclusion.

Prior to the codification, FAS 71 addressed the appropriate timing.

FAS 71, paragraph 69

Users of financial statements should be aware of the possibility of rapid, unanticipated changes in an industry, but accounting should not be based on such possibilities unless their occurrence is considered probable.

Based on this guidance, we believe application of ASC 980 should not be discontinued until it becomes probable that deregulation legislation and/or regulatory changes will occur and the effects are known in sufficient detail to be reasonably estimable.

17.8.2.1 *Timing of discontinuation when deregulatory legislation or a rate order exists*

ASC 980-20-40-6 provides specific guidance addressing the appropriate timing for the discontinuation of the application of ASC 980 to all or part of a business when deregulatory legislation is passed or when a rate order is issued that provides for a transition plan to deregulate. The guidance has been interpreted to mean that ASC 980 should be discontinued for the relevant separable portion of the business at the beginning, rather than the completion, of the transition period.

Excerpt from ASC 980-20-40-6

When deregulatory legislation is passed or when a rate order (whichever is necessary to effect change in the jurisdiction) that contains sufficient detail for the entity to reasonably determine how the transition plan will affect a separable portion of its business whose pricing is being deregulated is issued, the entity shall stop applying this Topic to that separable portion of its business.

17.8.3 Accounting for the discontinuation of ASC 980

The discontinuation of the application of ASC 980 by a regulated utility to all or a portion of its operations generally results in the elimination of assets and liabilities that were created out of the regulatory process, with the exception of certain portions of utility plant and inventory. The net effect of the adjustments should be included in income in the period of discontinuance.

Excerpt from ASC 980-20-40-2

When an entity discontinues application of this Topic to all or part of its operations, that entity shall eliminate from its statement of financial position prepared for general-purpose external financial reporting the effects of any actions of regulators that had been recognized as assets and liabilities pursuant to this Topic but would not have been recognized as assets and liabilities by entities in general.

In addition, once a regulated utility discontinues the application of ASC 980 to all or a portion of its operations, in accordance with ASC 980-20-35-1, it will no longer recognize regulatory assets or liabilities arising from those operations. If a reporting entity ceases to meet the criteria to apply ASC 980 yet continues to be subject to regulation, evaluation of the regulator's intentions will be necessary in determining whether any existing regulatory assets or liabilities continue to exist.

ASC 980-20-55 illustrates the accounting for the discontinuation of ASC 980. The following sections also discuss specific considerations related to various aspects of accounting for a discontinuation.

17.8.3.1 Derecognition of regulatory assets and liabilities

Regulatory assets and liabilities are generally eliminated as a result of discontinuation of regulatory accounting. In determining the amount of the adjustment, a key step in the process is to identify all of the reporting entity's regulatory assets and liabilities. Although some regulatory assets may be easy to identify, reporting entities also need to consider whether there are any regulatory assets or liabilities embedded in other balances or labeled differently (e.g., deferred credits). Examples of regulatory assets and liabilities that should be written off upon discontinuation of regulatory accounting are as follows:

- Regulatory assets and liabilities related to deferred income taxes recorded under ASC 740 for flow-through items and other tax regulatory differences

- Regulatory assets related to pension and other postretirement obligations
- Unamortized deferred gains or losses on debt refinancings
- The cumulative difference between capital lease expense and the amount of lease expense recognized under the rate process for capital leases
- Post-construction operating costs capitalized in plant accounts
- Regulatory assets embedded in plant arising from regulator-imposed depreciation methods (see UP 18.6 for further information on depreciation)
- Liabilities for revenue subject to refund
- Liabilities associated with the cost of removal of plant in-service

Reporting entities should evaluate regulatory liabilities prior to write-off to determine if they will remain obligations of the reporting entity and therefore continue as liabilities under U.S. GAAP in general. Pursuant to ASC 980-20-40-2, only liabilities recognized as a result of the regulatory process should be written off upon discontinuation of ASC 980.

Question 17-17

How should a reporting entity evaluate “common” assets and liabilities when ASC 980 is applied to a separable portion of the business?

PwC response

When discontinuation of ASC 980 is applied to a separate portion of the business, the accounting for common regulatory assets and liabilities (i.e., those that relate to more than one customer class, business segment, or other separable portion of the business) will depend on regulatory actions and other factors. There may be different approaches to determining the amount of write-off required for common regulatory assets. We believe one acceptable approach would be to write off a pro rata portion of the regulatory assets and liabilities based on the proportion of the amortization of the regulatory asset or liability allocated to the separate portion of the business in the most recent rate case. There may be other methods that are appropriate under the facts and circumstances.

In addition, if the reporting entity can establish that the regulator will allow specific recovery of the regulatory asset from a portion of the reporting entity’s operations that continue to qualify for application of ASC 980, a proportionate write-off may not be required pursuant to ASC 980-20-35.

17.8.3.2 Utility plant and inventory

ASC 980-20-35-2 through 35-5 and ASC 980-20-40-2 through 40-4 provide specific guidance for adjusting utility plant and inventory as part of the discontinuation of

regulatory accounting. In accordance with this guidance, the reporting entity should not adjust the carrying value of utility plant and inventory for the following amounts:

- Allowance for funds used during construction
- Intercompany profit
- Disallowances of costs of recently completed plant

However, the reporting entity should write off other amounts capitalized in utility plant or inventory as a result of regulator action when recording the effects of discontinuation of ASC 980. Examples of such types of costs include:

- Post-construction operating costs (costs the regulator allows to be capitalized from the time a plant is placed in service to the effective date of inclusion of the plant in rates)
- The cumulative difference, if any, between depreciation recorded based on rates and lives approved by the regulator and depreciation that would be recorded by entities in general (e.g., recovery of accelerated depreciation)

In addition, as part of the discontinuation of regulatory accounting, the reporting entity should perform an impairment analysis of utility plant in accordance with the guidance in ASC 360. In assessing the recoverability of the carrying amount of plant, the undiscounted cash flows used in the analysis should not include cash flows that will be recovered from any portion of the business that meets the criteria for continued application of ASC 980. See UP 18.7 for further information on impairment of utility plant.

17.8.3.3 *Stranded costs and other regulatory adjustments*

During the transition to a deregulated environment, regulators may provide regulated cash flows for the recovery of specified regulatory assets or to settle regulatory liabilities of a deregulated portion of the business. These transition charges are generally designed to recover a regulated utility's "stranded costs" arising from the part of the business that no longer meets the criteria to apply ASC 980. Stranded costs are generally costs that would not be recoverable by an unregulated entity in a competitive marketplace and may include items such as the above-market value of utility plant, purchase power contracts, and regulatory assets.

If recovery is provided for regulatory assets and regulatory liabilities that originated in the separable portion of a reporting entity to which ASC 980-20 is applied, the reporting entity should evaluate whether a full or partial write-off is required. If the regulator issues a rate order or other decision that such amounts will be recovered or refunded through future regulatory cash flows, the related existing balances will not be written off. The existing regulatory balances must be specified in the deregulatory legislation or transitional rate order to avoid a write-off. In accordance with ASC 980-20-35-7, such amounts will not be eliminated until one of the following events occurs:

- They are recovered or settled as the regulated cash flows are collected

- They are impaired, or in the case of a regulatory liability, they are eliminated by the regulator
- The separable portion of the business generating the regulated cash flows no longer meets the criteria for application of ASC 980

ASC 980-20-35-8 through 35-9 also provide similar guidance that permits capitalization of future regulatory assets and liabilities (i.e., not just those that existed at the date of discontinuation) arising from a deregulatory legislation or a transitional rate order. Similar to the guidance for the recognition of existing regulatory assets and liabilities, the potential future regulatory assets and liabilities must be specified in the legislation or transitional rate order. Furthermore, the related costs must be incurred after ASC 980 is discontinued.

It may be difficult to distinguish when it is appropriate to retain existing regulatory assets or liabilities or to record future regulatory assets and liabilities, once a reporting entity has discontinued the application of ASC 980. Unless there is specific transitional legislation or a rate order permitting such accounting, a reporting entity should record only balances and transactions related to the separable portion of the business pursuant to U.S. GAAP applicable to entities in general.

Question 17-18

Are securitized stranded costs financial assets?

PwC response

No. Reporting entities may sometimes securitize their enforceable right to impose a surcharge or tariff. When a reporting entity securitizes its stranded costs, it obtains cash from investors in exchange for future regulated cash flows representing the surcharge or tariff. Such securitizations are typically set up through a trust that sells the securities and administers the ongoing cash flows related to those securities.

ASC 860, *Transfers and Servicing*, provides specific guidance on securitized stranded costs and states that they do not meet the definition of a financial asset. ASC 860-10-55-7 through 55-8 indicate that securitized stranded costs are not financial assets because they are imposed on ratepayers through the surcharge or tariff (i.e., imposed by the government) and do not represent a right to receive payments from another party as a result of a contract. Therefore, reporting entities should evaluate transfers of stranded costs in a securitization transaction as a borrowing and consider consolidation requirements related to the securitization trust.

17.9 Reapplication of regulatory accounting

After a reporting entity has discontinued application of rate-regulated accounting, facts and circumstances may change such that ASC 980 should be reapplied. For example, a reporting entity may discontinue rate-regulated accounting due to uncertainty during a long rate freeze period. However, it may subsequently conclude that it is appropriate to reapply ASC 980 as a result of a return to full cost-based

regulation. Such reapplication is accounted for as a change in application of an accounting principle as a result of changed circumstances. There are several accounting implications for regulated utilities that reapply regulatory accounting to all or a separable portion of the business, as highlighted in Figure 17-8.

Figure 17-8
Impact of reapplication of ASC 980

Impact	Considerations
Record amounts that meet the definition of regulatory assets and liabilities	The carrying amounts of other assets and liabilities generally should not be adjusted, even if their carrying amounts may have been different had rate-regulated accounting never been discontinued.
Start recording an AFUDC if it is probable of future recovery (see UP 18.3)	Plant balances should not be adjusted for any difference that resulted from capitalizing interest under ASC 835 instead of AFUDC while rate-regulated accounting was discontinued.
Record assets for previously-disallowed incurred costs that are subsequently allowed by a regulator, consistent with classification if costs had been initially allowed	Reverse any impairment losses that were previously recorded under ASC 360 in connection with adopting ASC 980-20, if such amounts become probable of recovery as a result of a specific regulator action. See UP 18.7 for further information on regulatory accounting for impairment losses.

Chapter 18:
Regulated operations:
utility plant

18.1 Chapter overview

Utility plant is generally a regulated utility's most significant asset. The interaction of regulation with the accounting for utility plant can be particularly complex. Although regulated utilities are subject to the same capitalization and depreciation guidance applied by unregulated entities, there are specific requirements and nuances resulting from the regulatory environment. Authoritative guidance relating to regulated utility plant is primarily included in ASC 980. This chapter discusses key areas of focus for regulated utilities including:

- Capitalization policies
- Allowance for funds used during construction
- Depreciation
- Impairment
- Asset retirement and environmental obligations
- Lease accounting
- Intercompany plant sales between regulated and unregulated affiliates

See UP 12 for information on general plant matters that are relevant to both utilities and power companies and that are not specific to operating in a regulated environment. See UP 17 for further information on application of regulated accounting matters in general.

18.2 Capitalization

UP 12.2 discusses key considerations in accounting for plant construction, including capitalization of interest and other costs. In addition to considering that guidance, a regulated utility may have unique considerations in developing capitalization policies because regulators often permit recovery of costs that would otherwise be charged to expense. Regulated utilities generally capitalize the costs of developing and constructing a plant based on their expectation of regulatory recovery.

Only those incurred costs that are probable of recovery through future rates should be capitalized as part of utility plant (construction work in progress). Examples of expenses that regulated utilities may be able to recover that would otherwise be charged to expense include amounts relating to feasibility and engineering studies, contract negotiations, license applications, and related legal costs, along with the costs of engineering, planning and construction, operations and maintenance, financing, power purchase agreements, and other similar preconstruction and development costs. Factors to consider in determining whether these amounts should be capitalized are similar to those used to evaluate regulatory assets in general (see UP 17.3).

18.3 Allowance for funds used during construction

Constructing utility plant takes time, potentially resulting in the incurrence of significant carrying costs in advance of when the facilities are ready for use and included in allowable costs for ratemaking purposes. In most cases, a regulated utility does not earn a return on assets under construction to cover financing costs incurred during the construction period. Therefore, regulators typically allow utilities to capitalize an allowance for funds used during construction (AFUDC) for future recovery. ASC 980-835-30-1 requires capitalization of AFUDC if the regulated utility's regulator provides for its recovery. The primary difference between AFUDC and interest capitalized under ASC 835 is that AFUDC includes a component for equity funds. If AFUDC is capitalized, the regulated utility should record a corresponding increase in pre-tax income for the component for equity funds. See UP 21 for information on financial statement presentation of AFUDC.

See UP 19.2.2 for further information on income tax considerations related to the equity portion of AFUDC.

Question 18-1

If a regulator does not permit recovery of AFUDC, does it result in a disallowance of utility plant?

PwC response

No. As discussed in ASC 980-340-55-2, a regulator may permit recovery of an incurred cost without providing for any return (such as for a plant prior to completion and inclusion of the plant in rate base). The regulator's decision not to provide a return on an incurred cost does not impact the regulated utility's ability to record the underlying asset, except in the limited case of abandoned plants (see UP 18.7.1). Consistent with this guidance, a regulator's decision to deny recovery of AFUDC does not result in a disallowance or any adjustment to the carrying value of the plant under construction.

18.3.1 Criteria for capitalization of allowance for funds used during construction

In accordance with ASC 980-835-25-1 and 30-1, AFUDC should be capitalized only during periods of construction and only if it is probable that the regulated utility will receive subsequent recovery through the ratemaking process. Any amounts that are not probable of recovery should not be capitalized. Furthermore, pursuant to ASC 980-835-25-2, if AFUDC is not capitalized because future recovery through rates is not probable, the regulated utility should not alternatively capitalize interest cost under ASC 835-20, *Interest – Capitalization of Interest*.

Regulated entities capitalizing AFUDC should regularly monitor the status of construction and ensure capitalization of AFUDC at the allowed rate continues to be appropriate. If completion of construction for which AFUDC is being capitalized is no longer probable, or where there is or is expected to be a plant disallowance by the

regulator, the regulated utility should evaluate whether previously capitalized amounts should be written off and whether it should cease capitalizing AFUDC. In addition, when construction in progress is permitted in rate base, specific requirements regarding the capitalization of AFUDC may apply (see UP 18.4). Considerations regarding the capitalization of AFUDC during construction are addressed in ASC 980-835-25-2 through 25-4 and summarized in Figure 18-1.

Figure 18-1

Recognition of allowance for funds used during construction

Status of construction	Impact on AFUDC
Completion of the plant and recovery of all construction costs is probable	<ul style="list-style-type: none"> □ Capitalize AFUDC if recovery of AFUDC is probable
Completion of the plant is reasonably possible but no longer probable	<ul style="list-style-type: none"> □ Cease capitalizing AFUDC because recovery is no longer probable □ No adjustment to previously capitalized AFUDC; it should not be written off until disallowance of plant costs is probable
Disallowance of plant costs is reasonably possible	<ul style="list-style-type: none"> □ Identify range of possible disallowance and cease accruing AFUDC on costs equal to the maximum amount in the range, because recovery is no longer probable
Plant is probable of being abandoned or all or a portion being disallowed	<ul style="list-style-type: none"> □ Cease capitalizing AFUDC and apply abandonment or disallowance guidance for existing amounts as applicable

Example 18-1 illustrates the accounting for AFUDC when it is reasonably possible that a portion of the plant costs will be disallowed.

EXAMPLE 18-1

Application of AFUDC — cap on amount of AFUDC imposed by the regulator

On July 1, 20X4, Rosemary Electric & Gas Company (REG) began construction of the Camellia Generating Station, a 575 MW natural gas-fired power plant. The total cost of construction is budgeted at \$500 million. Construction is scheduled for completion in June 20X7. REG obtains an order from its regulator that:

- Approves recovery of construction costs up to \$500 million, subject to prudence review
- Allows AFUDC on the cost of construction, at REG's approved cost of capital (both debt and equity components)
- Orders REG to include the Camellia power plant in its rate base in its first general rate case subsequent to the plant being placed in service

REG starts capitalizing AFUDC. In 20X6, management determines that the total cost of construction will be \$600 million. Management discusses the expected cost overruns with the regulator; however, the regulator does not change the cap on construction costs permitted for recovery, subject to further evaluation in the next general rate case.

Should REG continue to capitalize AFUDC for amounts that exceed the original \$500 million once it determines that the cost of construction will exceed the cap approved by the regulator?

Analysis

No. As a result of the cap, recovery of AFUDC is not probable on any construction costs incurred in excess of \$500 million. AFUDC could continue to be recorded on expenditures up to \$500 million; however, no AFUDC should be applied on amounts in excess of the cap. In addition, REG will need to assess whether a disallowance should be recorded on the construction costs in excess of the cap.

See UP 18.7.2 for further information on accounting for disallowances of recently-completed plant.

18.3.2 *Deferral of shareholder return outside the construction period*

Due to the timing of rate case filings, regulators may allow a regulated utility to recover a carrying cost (including both debt and equity return, similar to AFUDC) on the value of plant placed in service from the commercial operation date to the effective date of inclusion of the plant in rates charged to customers. A regulated utility may also request other similar arrangements to compensate it for delays in including significant capital projects in rate base.

ASC 980-340-25-5 through 25-6 clarify that regulated utilities applying ASC 980 are not permitted to capitalize the cost of equity, except while a plant is under construction.

Excerpt from ASC 980-340-25-5

If specified criteria are met, paragraph 980-340-25-1 requires capitalization of an incurred cost that would otherwise be charged to expense. An allowance for earnings on shareholders' investment is not an incurred cost that would otherwise be charged to expense. Accordingly, such an allowance shall not be capitalized pursuant to that paragraph.

Consistent with this guidance, although a regulator may permit a utility to recover the "cost" of equity in rates, the regulated utility should not capitalize the equity component or otherwise record a regulatory asset, regardless of whether future recovery is probable. For purposes of financial reporting, the equity component should not be recognized until it is collected through rates. However, if recovery is probable, it would be permissible to defer debt-only carrying costs as a regulatory asset. Any debt-related amounts capitalized under this type of arrangement should be classified as a regulatory asset, not as part of the utility plant balance. Furthermore, the regulated utility should

base the amount deferred on its actual interest costs incurred associated with that plant or capital project. It would not be appropriate to base the rate on the regulated utility's hypothetical capital structure.

18.3.2.1 Application examples — carrying costs

Examples 18-2 and 18-3 illustrate the capitalization of debt-only carrying costs.

EXAMPLE 18-2

Recovery of carrying costs — acquisition financed through debt issuance

On February 1, 20X4, Rosemary Electric & Gas Company (REG) acquires a 300 MW combined-cycle natural gas-fired electric generation plant for \$250 million. The next general rate case is not expected until 20X6; therefore, REG petitions for and receives approval from its regulator to:

- Defer operating and maintenance expense, depreciation, taxes, and cost of capital invested in rate base beginning with the filing date of the petition and ending with the effective date of new rates from the 20X6 general rate proceeding
- Defer monthly carrying costs on the deferred costs at its approved rate of return of 10% until amortization begins
- Recover the deferred amounts over the three-year period commencing the earlier of January 1, 20X5, or the effective date of implementation of new rates from the general rate case

The approved carrying cost of 10% includes an equity component. REG's weighted-average debt cost is 6.5%. The acquisition of this facility was financed through issuance of new debt with financing cost of 5%.

How should REG account for its carrying costs during the period from receipt of its rate order until the implementation of new rates?

Analysis

For financial reporting purposes, REG should defer only the carrying cost related to the cost of debt. Although the regulator approved recovery of REG's full cost of capital, in accordance with ASC 980-340-25-5 through 25-6, REG would not be permitted to defer equity carrying costs because the plant was acquired and not under construction (where deferral of equity carrying costs would be permitted as part of AFUDC). The amount deferred each period should be equal to the actual cost of the debt used to finance the facility. The regulated utility should record deferral of debt cost as a regulatory asset separate from utility plant.

EXAMPLE 18-3

Recovery of carrying costs — acquisition financed through general funds

Assume the same facts as Example 18-2, except that REG financed acquisition of the new facility through its general funds.

How should REG account for its carrying costs during the period from receipt of its rate order until the implementation of new rates?

Analysis

Similar to the analysis in Example 18-2, REG would not be permitted to defer its equity-related carrying costs. Furthermore, because acquisition of the facility was financed through general funds, REG would need to estimate the amount of debt costs associated with the acquisition. One approach to determining the amount to defer is to multiply the carrying value of the facility by its weighted-average cost of debt. The rate used to calculate the amount deferred should be updated periodically. In addition, amounts deferred should be recorded in a regulatory asset separate from utility plant.

18.3.3 Capitalization of interest on a regulated equity method investee

ASC 835-20-15-6(e) and 55-3 provide guidance on the investor's accounting for capitalized interest related to an investment in a regulated investee that the investor accounts for under the equity method. In accordance with this guidance, a reporting entity that holds an investment in a regulated utility and accounts for its investment under the equity method is not permitted to capitalize interest on its investment. The regulated investee capitalizes AFUDC during the construction period, which is recognized indirectly by the investor in its income statement through its equity method earnings.

18.4 Construction work in progress in rate base

As an alternative to capitalizing AFUDC during the construction period, a regulator may permit a regulated utility's construction work in progress (CWIP) balance to be included in rate base before the plant is completed and placed in service. This provides the regulated utility with a return on a portion of its investment during the construction period. In such cases, no AFUDC is provided because the regulated utility is receiving a current return on its carrying costs.

Another recovery alternative is to allow a current return on a regulated utility's capital investment during construction through a rate rider mechanism. Under this alternative, a regulated utility bills and recovers an approved return from customers while the plant is being constructed. As a result, the regulated utility would record no AFUDC because the utility is currently recovering the cost of financing. This approach may be adopted for infrastructure replacement programs or environmental expenditures.

A third, but less common, approach to recovery of carrying costs is referred to as “mirror CWIP.” Under this approach, a portion of construction work in progress is allowed in rate base during the construction period. After the utility plant is placed in service, a decreasing amount of construction work in progress is excluded from rate base each year, “mirroring” the pattern in which the construction was included in rate base. As a result, rates are increased during the construction period, thus reducing the rate increase necessary when the plant is placed in service. In effect, the utility collects a return on and of a portion of the construction cost before the utility plant is placed in service.

With mirror CWIP, the ratemaking differs from the accounting. The guidance on mirror CWIP is included in ASC 980-340-55-4 through 55-8. Although AFUDC may not be allowed during the construction period for ratemaking, it should be capitalized on the total cumulative construction cost in each financial reporting period. In accordance with ASC 980-340-55-7, the utility should record revenue collected as a result of including construction work in progress currently in rate base as a liability to customers, with disclosure of the expected period of repayment to customers.

18.5 Financing through construction intermediaries

SAB Topic 10.A, *Financing By Electric Utility Companies Through Use Of Construction Intermediaries* (SAB Topic 10.A), which was codified in ASC 980-810-S99-2, provides guidance on the presentation of construction work in progress and capitalized interest when a regulated utility uses a third party to finance construction of a generating plant.

The typical case described by the guidance involves establishing a trust or corporation (construction intermediary) to which the utility assigns its interest in property or other contractual rights. The construction intermediary finances the construction, guaranteed by the construction work in progress as well as by the obligation of the utility to purchase the plant at the completion of construction. In some cases, the utility also may commit to make up deficiencies in the funding provided by the construction intermediary. During construction, interest will be capitalized. The question that arises in these structures is whether the construction work in progress, related liabilities, and interest expense being generated by the construction intermediary should be presented on the utility’s financial statements.

SAB Topic 10.A requires these amounts to be reported in the utility’s financial statements in the applicable captions (effectively concluding that the construction intermediary should be consolidated by the utility). We would generally expect a consolidation conclusion to be consistent with the application of ASC 810¹. However, reporting entities applying this guidance should also evaluate the impact of ASC 810 when evaluating the appropriate accounting for these structures.

¹ As noted in UP 1.2.3, the FASB issued amended consolidation guidance in February 2015.

18.6 Depreciation

In general, regulated utilities record depreciation of utility plant over a period and in a pattern that is consistent with recovery periods approved in the regulatory process. This section discusses some of the challenges arising from the interaction between regulatory recovery and depreciation requirements under U.S. GAAP for entities in general. See UP 12.3 for further information on accounting for depreciation not specific to a regulated environment.

18.6.1 Phase-in plans

ASC 980-340 provides guidance on accounting for phase-in plans. Under a phase-in plan, a regulator delays a regulated utility's recovery of utility plant, typically to avoid significant increases in rates.

Definition from ASC 980-340-20

Phase-In Plan: Any method of recognition of allowable costs in rates that meets all of the following criteria:

- a. The method was adopted by the regulator in connection with a major, newly completed plant of the regulated entity or of one of its suppliers or a major plant scheduled for completion in the near future.
- b. The method defers the rates intended to recover allowable costs beyond the period in which those allowable costs would be charged to expense under generally accepted accounting principles (GAAP) applicable to entities in general.
- c. The method defers the rates intended to recover allowable costs beyond the period in which those rates would have been ordered under the rate-making methods routinely used prior to 1982 by that regulator for similar allowable costs of that regulated entity.

In general, phase-in plans include any form of ratemaking whereby plant-related costs are deferred and included in rates over a period that is longer than the costs would otherwise be recognized under U.S. GAAP, including:

- A phased inclusion of utility plant in rate base
- Straight-line recovery of a lease relating to recently-completed plant that is accounted for as a capital lease under U.S. GAAP
- Alternative methods of depreciation that would not be permitted under U.S. GAAP, such as a sinking fund or annuity approach (whereby the depreciation increases over time)
- A lower rate of depreciation on rate base than otherwise would be recognized under U.S. GAAP (e.g., a longer useful life being used for ratemaking purposes)

ASC 980-340-25-2 and 25-3 provide the general guidance for phase-in plans.

ASC 980-340-25-2

If a phase-in plan is ordered by a regulator in connection with a plant on which no substantial physical construction had been performed before January 1, 1988, none of the allowable costs that are deferred for future recovery by the regulator under the plan for rate-making purposes shall be capitalized for general-purpose financial reporting purposes (hereinafter referred to as financial reporting). Allowable costs that are deferred for future recovery by the regulator under the plan consist of all allowable costs deferred for rate-making purposes under the plan beyond the period in which those allowable costs would be charged to expense under generally accepted accounting principles (GAAP) applicable to entities in general.

As noted in this guidance, a regulated utility may not defer any amounts associated with a phase-in plan on a plant for which no substantial construction had been performed prior to January 1, 1988.

Due to this timing requirement, we generally would not expect any amounts related to a phase-in plan for new plants or plant additions placed into service now to qualify for deferral. As a result, any regulator-imposed deferral of plant recovery, or effects of a delay of or adjustment to depreciation expense required by U.S. GAAP applicable to entities in general, should be immediately expensed, except in the limited circumstances discussed in Question 18-3.

ASC 980-340-55 provides implementation guidance, including illustrative examples, on the accounting for phase-in plans.

Question 18-2

Does the guidance on phase-in plans apply only to newly-constructed plant?

PwC response

Generally, yes. The guidance prohibits regulated utilities from deferring any costs associated with a phase-in plan on a newly-completed plant (unless the plant was completed or substantial construction had been performed by January 1, 1988, which would not apply to any current construction). We believe that this guidance applies to any major plant, or plant addition, that has not been through a previous rate case. See Question 18-8 for a similar discussion of the meaning of “recently-completed plant.”

Question 18-3

Is it ever acceptable to recognize a depreciation-related regulatory asset arising from newly-completed plant?

PwC response

Generally, no. The guidance limits deferral of any plant-related costs associated with a phase-in plan, unless the plant was completed or substantial construction was

performed prior to January 1, 1988. Therefore, a phase-in plan associated with a new plant would not be eligible for deferral of plant-related amounts as a regulatory asset.

However, there are limited circumstances when a depreciation deferral would not meet the definition of a phase-in plan. The definition of a phase-in plan includes the following criterion:

Excerpt from ASC 980-340-20

Phase-in Plan:

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

In accordance with this guidance, a depreciation deferral scheme would not meet the definition of a phase-in plan if the regulator had followed a similar approach for recovery of similar assets for that specific utility prior to 1982. This exception is interpreted narrowly. Therefore, the phase-in plan guidance would still apply if the depreciation method was used by another regulator, by other utilities, or for other assets of the same utility. As such, in general, any deferral of depreciation on newly-constructed assets is prohibited.

Question 18-4

Is it acceptable to recognize a regulatory asset associated with decelerated cost recovery of an existing plant?

PwC response

Generally, no. Current recovery of costs is a basic premise of regulatory accounting. In the Basis for Conclusions of FAS 92, the FASB discussed its concern with rate plans that delayed recovery of plant costs and how these arrangements may raise questions about the application of regulatory accounting. Therefore, we generally believe that reporting entities should not record regulatory assets as a result of a regulator plan to delay recovery of plant costs.

In general, a regulated utility that receives an order to slow down depreciation or delay recovery of plant costs should recognize depreciation based on U.S. GAAP requirements and no regulatory assets or embedded regulatory assets should be recognized. However, there are many different regulatory approaches for plant recovery and there may be situations when recognition of a depreciation-related regulatory asset would be appropriate.

Given the complexity and the judgment required, a reporting entity should consider discussing the facts and circumstances with an advisor prior to recognition of depreciation following a pattern slower than that allowed under U.S. GAAP for reporting entities in general.

Question 18-5

Are newly-created regulated entities required to apply the phase-in plan guidance?

PwC response

Yes. The guidance on phase-in plans applies to all entities subject to ASC 980. Furthermore, in evaluating whether a cost recovery scheme is subject to the phase-in plan guidance, such entities would not be eligible for the limited exception discussed in Question 18-3, as a newly-created entity would have no history with the regulator prior to 1982. However, we believe that a reporting entity could consider the experience of a predecessor entity in considering whether this exception applies.

18.6.2 Accelerated cost recovery of plant

Regulators may at times require a regulated utility to apply a depreciation method for ratemaking purposes that is faster than straight-line depreciation for financial reporting purposes. Such an approach gives rise to a regulatory liability. The resulting regulatory liability should be presented separately on the balance sheet rather than as a balance recorded within accumulated depreciation. The SEC staff has questioned regulated utilities that have embedded regulatory liabilities within accumulated depreciation and has required reclassification of those amounts as separate liabilities. In addition, the SEC staff has commented that the resulting regulatory liability should be disclosed. If the amount of the regulatory liability is not known, the regulated utility should provide additional disclosure, including:

- The consequence of the ratemaking process to the recognition of depreciation expense
- The extent to which regulatory recovery periods differ from the useful lives that would have been used absent regulatory accounting
- A statement that quantification of the cumulative effect of the difference cannot be determined

In addition, the effect of classifying accelerated recovery within utility plant results in a difference between the carrying amount of the utility plant under U.S. GAAP for reporting entities in general and the recorded amount based on the regulator's actions. Any such amounts should be written off when discontinuing the application of regulatory accounting (see UP 17.8).

18.6.3 Other depreciation recovery methods

In some situations, for rate-making purposes, a regulator or regulated utility may propose changes to depreciable lives or other adjustments that result in amounts that would differ from accounting based on normal GAAP. For example, during the deregulation of certain service territories in the past, there were proposals to transfer accumulated depreciation between asset classes or to record incremental depreciation under specific conditions, such as during periods of extra profits or in response to other cost reductions. The SEC staff has stated that reclassifications of accumulated depreciation do not appear to conform to either U.S. GAAP for entities in general or

deferral under ASC 980, and that any registrant contemplating such a reclassification should first consult with the SEC’s Office of the Chief Accountant.

There may be other instances when regulators or regulated utilities may propose various other methods to recover utility plant assets. In evaluating the accounting for these types of arrangements, regulated utilities should ensure that the depreciation method applied does not result in recognition over a period that would be longer than that permitted under U.S. GAAP for entities in general (see UP 18.6.1 and the response to Question 18-4).

18.7 Impairment

This section addresses impairment guidance related to construction work in progress and utility plant. As summarized in Figure 18-2, the recognition and measurement models vary depending on whether the impairment relates to an abandonment, disallowance of recently-completed plant, or other plant impairment.

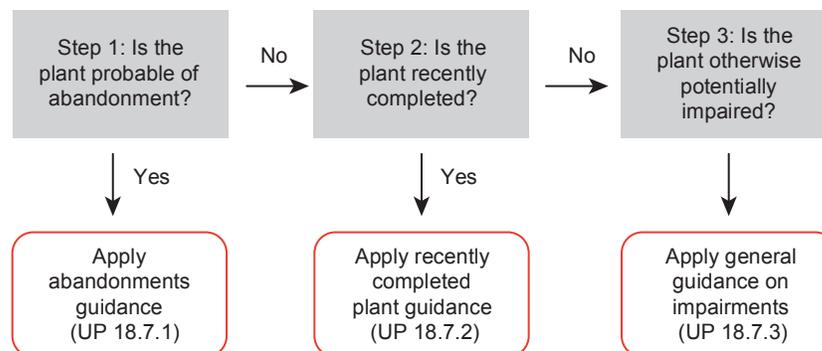
Figure 18-2
Accounting for impairments of utility plant

	Initial measurement	Subsequent measurement
Abandonments (UP 18.7.1)	<ul style="list-style-type: none"> □ Loss on abandonment is measured based on difference between carrying value and present value of future cash flows (ASC 980-360-35) □ Any amounts to be recovered are recorded as a regulatory asset 	<ul style="list-style-type: none"> □ Record subsequent changes in recovery amounts as an adjustment to the regulatory asset
Disallowances of recently-completed plant (UP 18.7.2)	<ul style="list-style-type: none"> □ ASC 980-360-35 requires loss recognition of any disallowance as a reduction of the utility plant balance 	<ul style="list-style-type: none"> □ Record subsequent regulatory recoveries as utility plant
Other utility plant impairments (UP 18.7.3)	<ul style="list-style-type: none"> □ ASC 360 two-step impairment model requires assessment upon a triggering event; any impairment is measured based on fair value □ Any impairment is a reduction to the utility plant balance 	<ul style="list-style-type: none"> □ ASC 360 does not allow subsequent increases in plant □ Record regulatory recoveries, if any, as a regulatory asset

Because of the differences in recognition and measurement among the accounting models, determining which guidance applies is critical to the measurement and recognition of a potential impairment of regulated utility plant. Figure 18-3 summarizes key questions to consider in determining the appropriate accounting model.

Figure 18-3

Determining which accounting model to apply to an impairment of regulated plant or construction in progress



18.7.1 Abandonments

A regulated utility may abandon construction of utility plant or plant in service due to various factors, including increasing costs of completing construction, expected declines in demand, or increased operating costs due to regulatory or other changes (e.g., changes in emission laws). ASC 980-360-35-1 through 35-8 provide guidance on accounting for abandonments by regulated utilities.

ASC 980-360-35-1

When it becomes probable (likely to occur) that an operating asset or an asset under construction will be abandoned, the cost of that asset shall be removed from construction work-in-process or plant-in-service.

A regulated utility should recognize a loss on abandonment when it becomes probable that all or part of the cost of an asset will be disallowed from recovery in future rates and such amount is reasonably estimable. It should record the amount that the regulated utility expects to recover, if any, as a new regulatory asset.

As discussed in ASC 980-360-35-3, the new regulatory asset should be based on the present value of the future revenues for the allowed recovery of abandoned plant. The discount rate used to calculate the present value of future revenues should be the regulated utility's incremental borrowing rate. Regulated utilities should also consider the recovery of any asset retirement obligation in connection with the abandoned plant. Figure 18-4 highlights the concepts for calculating the value of the regulatory asset for an abandoned plant that will be recovered in rates. The measurement of the regulatory asset and the subsequent amortization will depend on whether the regulator permits full, partial, or no recovery of return.

Figure 18-4

Recognition and measurement of a regulatory asset recognized in connection with a plant abandonment

	Full return likely to be provided	Partial or no return likely to be provided
Measurement of the regulatory asset recognized when the abandonment is probable	Carrying basis of the abandoned plant less the amount of any cost disallowance	Present value of the future revenues expected to be provided to recover the allowable cost of the abandoned plant
Accounting for the regulatory asset during the period between the date the regulatory asset is recognized and the date recovery begins	Asset is increased for carrying charges; calculated using allowed overall cost of capital in the jurisdiction where recovery will be provided	Carrying charge calculated using rate used for the present value calculation
Amortization of the regulatory asset during the recovery period	The same manner as that used for ratemaking purposes	In a manner that will produce a constant return consistent with the rate used for the present-value calculation

The guidance results in the regulated utility recording a loss in the income statement for any amounts that ultimately are not recovered through future rates, including:

- Any portion of the cost of the abandoned utility plant that is disallowed
- Any disallowance of return (i.e., a partial or no return)

The regulated utility should record the new asset and any loss to be recognized when the loss is probable and the amount is reasonably estimable. Prior to receipt of a regulatory order, determining whether to apply the abandonment accounting model may be a matter of judgment. In most cases, the abandonment model will be applied at the time the initial rate order is received. However, the lack of a regulatory order would not preclude accounting for the abandonment if the loss is probable and reasonably estimable. Factors to consider include the nature of the abandonment, the regulated utility’s historical experience and past practice, and the current policies of the regulator with respect to abandonments.

If the criteria for loss recognition (i.e., the loss is probable and reasonably estimable) are not met before or at the time of a rate order (because the regulator does not finalize the amount and timing of the future revenues to be provided), the loss should not be recognized at that time. The regulated utility should recognize the loss once the future cash flows are probable and reasonably estimable.

If new information becomes available that indicates that the estimates used to record the new regulatory asset have changed, the regulated utility should adjust the amount

of the asset recorded. However, no adjustment should be made as a result of changes in the regulated utility's incremental borrowing rate. Any subsequent change to the estimate of the abandonment loss should be recorded as a gain or loss in the income statement.

Question 18-6

Does the abandonment accounting model apply to all utility plant, including plant in service, or only to construction in progress and newly completed plant?

PwC response

ASC 980-360-35-1 states that the abandonments guidance applies to “an operating asset or an asset under construction.” In the Basis for Conclusions of FASB Statement No. 90, *Regulated Enterprises—Accounting for Abandonments and Disallowances of Plant Costs—an amendment of FASB Statement No. 71 (FAS 90)*, paragraph 43, the FASB provided the following context:

Excerpt from FAS 90, paragraph 43

Recently, abandonments of plants under construction have become more common, and some utilities have abandoned plants during the later stages of construction. In many cases, the cost of abandoned plants is much greater than in the past.

This paragraph suggests that the guidance was primarily intended to address issues associated with plants under construction; however, the final guidance specifically scopes in “operating assets.” Therefore, we believe the guidance on abandonments should be applied to all abandoned plants, not just those that are newly-completed or for which construction is in progress.

Question 18-7

What is the impact on the accounting for an abandonment if the plant will continue to operate for some period after the criteria for recognition has been met?

PwC response

As a result of ongoing changes in environmental regulations, many regulated utilities are contemplating abandoning plants that were expected to be in service for much longer periods. In some cases, the criteria for abandonment accounting may be met for some period before the regulated utility expects to physically abandon the facility. However, the guidance on abandonments indicates that the loss should be recorded and amounts to be recovered, if any, should be reclassified to a regulatory asset at the time the abandonment is probable. Therefore, a question arises as to the accounting during the period the plant is still in operation.

The Basis for Conclusions of FAS 90, paragraph 44 addressed this.

FAS 90, paragraph 44 of Basis for Conclusions

...an abandonment changes the nature of the asset. A plant under construction is expected to produce utility services that have value. An abandoned plant can produce no services. Any value that results from the abandoned plant is limited to the revenues that will be furnished through the sales of services provided by other plants.

This paragraph highlights the difference between a utility plant asset, which is providing revenue through operations, and cost recovery associated with an abandoned plant. Consistent with this concept, we believe it would be acceptable to reclassify to a regulatory asset only that portion of the recovery expected to occur after the plant is abandoned. The regulated utility should record the reclassification and any related loss at the time the abandonment becomes probable, consistent with guidance in ASC 980-360-35. The utility should recognize the balance still classified in utility plant over the period remaining until the plant is abandoned. Therefore, in such situations, an adjustment to the estimated life of the asset and, accordingly, the rate of depreciation, is likely appropriate to recover the asset while it is still providing service.

18.7.1.1 *Income tax considerations*

Although the net loss on an abandonment is determined by discounting future after-tax revenues, the presentation of the loss on a net-of-tax basis is not allowed in accordance with ASC 980-740-25-1(a). As a result, the net loss on abandonment is grossed up for presentation purposes. Reporting entities should refer to the guidance in ASC 980-360-35-9 through 35-11 and ASC 980-360-55-2 through 55-13 (Example 1) when evaluating the income tax effects.

18.7.2 *Disallowance of recently-completed plant*

Some regulators require construction or management audits to assess whether expenditures incurred in construction projects have been prudent and should be included in rate base. As a result of these audits or based on other factors, regulators may partially or totally disallow capitalized construction costs from rate base, cost-of-service recovery, or both. ASC 980-360-35 provides guidance on the accounting for disallowances of recently-completed plants and requires loss recognition of any disallowed amounts on a dollar for dollar basis. This model is different from the impairment model under ASC 360, which requires a recoverability test and then measures impairments by comparing the carrying value of the utility plant to its fair value. Due to the differences in loss recognition under the two models, the determination of when the guidance in ASC 980-360-35 applies is important.

In accordance with ASC 980-360-35-12, when a regulated utility concludes it is probable that part of the cost of a recently-completed plant will be disallowed for ratemaking purposes, and a reasonable estimate of the amount of the disallowance can be made, it should record such amount as a loss. In addition, a regulated utility may become aware of a disallowance prior to construction being completed, in which case the utility should recognize a loss at that time if the disallowance is probable. ASC 980-360-35-12 also requires recognition of a loss if part of the cost of a recently-

completed plant is explicitly but indirectly disallowed. An indirect disallowance occurs when, for example, no return or a reduced return on investment is permitted on all or a portion of the new plant for an extended period of time.

As discussed in ASC 980-360-55-29, to determine the loss resulting from an indirect disallowance, the utility should first calculate the present value of the future revenue stream allowed by the regulator by discounting the expected future revenues using the last allowed rate of return. The utility should compare this amount to the recorded plant amount and record the difference as a loss. The utility should depreciate the remaining asset consistent with the ratemaking approach and in a manner that would produce a constant return on the undepreciated asset equal to the discount rate. Any subsequent changes in regulatory recovery should be recorded as an adjustment to the utility plant balance.

Question 18-8

What is meant by “recently-completed plant”?

PwC response

We have interpreted “recently-completed plant” as utility plant, or an addition to utility plant, that has been placed in service but that has not been through an initial rate case. We do not believe the length of time between completion of the plant (or addition) and finalization of the rate case is a factor in the interpretation of what should be included within recently-completed plant. The determination is based on whether the plant has previously been through a rate case after being placed in service, regardless of the length of time after completion of construction.

Question 18-9

Should the accounting for disallowances of costs of recently-completed plants also be applied to cost disallowances not related to a recently-completed plant?

PwC response

No. Prior to the codification, in the Basis for Conclusions of FAS 90, paragraph 63, the FASB considered requiring application of the loss recognition accounting to all cost disallowances by a regulator, whether related to recently-completed plant or other situations. The FASB decided to limit the guidance on disallowances to the specific issues that caused it to add the project to its agenda (i.e., recently-completed plant). See UP 18.7.3 for a discussion of other impairments of utility plant.

Question 18-10

In what situations would a disallowance of part of the cost of a recently-completed plant indicate that a regulated utility should consider discontinuing the application of ASC 980?

PwC response

The fact that a regulator is unwilling to approve rates based on the current cost of service may call into question the basic premise of ASC 980. Specifically, ASC 980-360-35-13 and 35-14 indicate that when a regulator orders a disallowance without a specific finding as to excess capacity or timing of construction, the rate order raises questions as to whether the regulated utility is being regulated based on its own cost of service.

In our view, a plant disallowance is ordinarily an unusual, nonrecurring event and is only one factor to be considered in the continued application of ASC 980. Reporting entities faced with a disallowance of recently-completed plant or other regulatory deferrals, such as a phase-in plan, should evaluate factors similar to those considered when recognizing regulatory assets (e.g., state regulatory history, cost forecasts, and the proposed length of the recovery period). The regulated utility should also consider whether it will recover substantially all of the carrying values of its assets and periodic operating costs through the regulatory process on an ongoing basis.

18.7.3 Other utility plant impairments

If a regulated utility has a potential impairment of utility plant that does not fall within the scope of ASC 980-360, it should follow the guidance for impairment of long-lived assets in ASC 360.

As described in UP 18.7.2, the distinction between a disallowance of recently-completed plant and an impairment of utility plant in service is important due to differences in the models applied to recognize and measure any loss. In addition, long-lived assets that have been impaired in accordance with the guidance in ASC 360 may not be reestablished or written up in subsequent periods. The regulated utility should record any subsequent amounts allowed by the regulator through a specific rate action as a regulatory asset, if the criteria of ASC 980-340-25-1 are met.

18.8 Asset retirement and environmental obligations

Regulated utilities have certain specific considerations when accounting for asset retirement and environmental obligations as highlighted in this section. See UP 13 for further information on accounting for asset retirement and environmental obligations by utilities and power companies.

18.8.1 Asset retirement obligations

Regulated utilities often receive rate allowances for the disposition and retirement of utility plant assets. Rates may include amounts for obligations that meet the

accounting definition of an asset retirement obligation as well as funds to cover decommissioning costs for which no legal obligation exists and no liability is recorded under other relevant accounting guidance (i.e., “cost of removal”). This section discusses considerations for regulated utilities in accounting for all such amounts collected through rates. The allowance for depreciation included in a regulated utility’s rates often includes a component for the expected cost of plant removal (also known as negative salvage). In some cases, the regulated utility may have a legal obligation that meets the definition of an asset retirement obligation (e.g., the requirement to decommission a nuclear plant). In other cases, the regulated utility may not have an explicit current obligation resulting from a past event. These situations should be evaluated to determine if an asset retirement obligation has been established under the doctrine of promissory estoppel.

Although the utility and regulator may not have agreed on a specific retirement plan, if such costs are included in determination of the utility’s revenue requirement, customers may have a reasonable expectation that the regulated utility will incur the costs necessary to retire the asset at the end of its useful life. This expectation would create an asset retirement obligation in accordance with the criteria of ASC 410 only if a legal obligation exists. The determination of whether the reporting entity has an asset retirement obligation is a legal question that it should evaluate with the assistance of legal counsel.

If a regulated utility concludes that no legal obligation exists, it should evaluate any negative salvage or cost of removal amounts collected in rates to determine if it should recognize a regulatory liability in accordance with ASC 980-405-25-1. At the time of adoption of ASC 410, the SEC staff expressed the view that the accrual of removal costs that do not meet the definition of an asset retirement obligation is acceptable under U.S. GAAP only if such amounts meet the definition of a regulatory liability. Any regulatory liability recognized should be classified as a liability on the balance sheet and not as an offset to utility plant.

18.8.1.1 *Regulatory assets and liabilities related to asset retirement obligations*

ASC 980-410 requires a regulated utility to recognize plant decommissioning costs and other asset retirement obligations in accordance with the general guidance in ASC 410. It further states that plant decommissioning costs represent costs incurred in the past (i.e., as the plant is used) and do not qualify as regulatory liabilities under ASC 980-405-25-1(b). However, in some cases, there may be timing differences between amounts recognized under ASC 410 and amounts allowed in rates. In accordance with ASC 980-410-25-2, a regulated utility should recognize a regulatory asset or liability for differences in the timing of recognition of costs associated with an asset retirement obligation and collection of such amounts through rates if it is probable that such amounts will be recovered.

18.8.2 *Environmental obligations*

Regulated utilities often have significant environmental clean-up costs. These types of costs may be incurred over a long period. The determination of whether to accrue a liability for these costs depends on the facts and circumstances. Regulated utilities should follow the guidance in ASC 410-30 and ASC 450-20.

SAB Topic 10.F, *Presentation of Liabilities for Environmental Costs* (codified in ASC 980-410-S99-1), also provides specific guidance related to the potential impact of regulatory recovery on the accounting for environmental remediation liabilities:

- A regulated utility may not present estimated liabilities for environmental costs net of probable future revenue resulting from the inclusion of such costs in allowable costs for ratemaking.
- A regulated utility may not delay recognition of a probable and estimable liability for environmental costs while a regulator debates potential recovery of the costs.

The SEC guidance indicates that an environmental remediation liability may be an allowable cost that qualifies for recognition as a regulatory asset. However, consistent with the overall model for application of the impact of regulation, a reporting entity should evaluate, measure, and record environmental remediation liabilities in accordance with the U.S. GAAP guidance for entities in general. Any potential regulatory recovery should be evaluated and recognized in accordance with the criteria in ASC 980-340-25-1.

18.9 Lease accounting

In some cases, a regulated utility's recovery of lease costs through rates is different from the expense recognition and accounting for the lease under U.S. GAAP. However, ASC 980-840-45-2 indicates that the classification of a lease is not affected by a regulator's actions; a regulator cannot eliminate a liability that it did not impose. Therefore, if a lease is classified as a capital lease under ASC 840, the balance sheet should reflect the capitalized lease asset and the related lease liability, even if lease costs are recovered through rates in a manner that is similar to an operating lease (e.g., straight-line rental expense). Application of this guidance is further discussed in the following sections.

18.9.1 Impact of regulation on lease expense recognition

Although the balance sheet classification and presentation of a capital lease is not impacted by regulation, ASC 980 provides that the timing of expense recognition should conform to the rate treatment, except with respect to recently-completed plant (see UP 18.9.1.1).

ASC 980-840-45-3

The nature of the expense elements related to a capitalized lease (amortization of the leased asset and interest on the lease obligation) is not changed by the regulator's action; however, the timing of expense recognition related to the lease would be modified to conform to the rate treatment. Thus, amortization of the leased asset shall be modified so that the total of interest on the lease obligation and amortization of the leased asset shall equal the rental expense that was allowed for rate-making purposes. For newly completed plants such regulatory treatment could result in a phase-in plan as defined in Subtopic 980-340.

Under ASC 840, the payments on a capitalized lease obligation are allocated between interest expense and a reduction of the lease obligation, producing a constant periodic rate of interest. In contrast, in accordance with the ASC 980-840 general guidance, the amortization of the leased asset plus the interest on the lease obligation will equal the rental expense allowed by the regulator. This guidance forces the amortization of the leased asset to equal the difference between the rental expense for rate purposes and the interest expense calculated in accordance with ASC 840. This generally results in lower leased asset amortization expense in the earlier years for a regulated utility applying this guidance compared with what would be recorded by an unregulated entity applying straight-line depreciation.

Example 18-4 illustrates the mechanics of calculating capital lease amortization and interest expense if operating lease treatment is required for regulatory purposes.

EXAMPLE 18-4

Regulatory lease expense recognition

On January 1, 20X4, Rosemary Electric & Gas Company (REG) leases an asset for use in its regulated operations. Assume the following:

- The fair value at inception of the lease is \$20,000.
- The lease term is five years, which is also the asset's economic life.
- The interest rate implicit in the lease is 15.24%.
- The annual rental (due on December 31 of each year) is \$6,000.

REG concludes that the lease should be classified as a capital lease in accordance with ASC 840; however, the regulator allows recovery of rental expense on a straight-line basis as payments are made. For purposes of this example, assume that the asset is not recently-completed plant.

How should REG account for its lease of the asset?

Analysis

Because the amount allowed in rates differs from the timing of expense recognition under capital lease accounting, REG should follow the guidance in ASC 980-840. The resulting income statement and balance sheet entries and amounts over the term of the lease are as follows:

Year	Entries	Cash	Leased asset	Capitalized lease obligation	Interest expense ^(a)	Amortization of leased asset ^(b)
1/1/X4	Record initial lease		\$20,000	(\$20,000)		
20X4	Lease payment	(\$6,000)		2,952	\$ 3,048	
	Amortization		(2,952)			\$ 2,952

Year	Entries	Cash	Leased asset	Capitalized lease obligation	Interest expense ^(a)	Amortization of leased asset ^(b)
20X5	Lease payment	(6,000)		3,402	2,598	
	Amortization		(3,402)			3,402
20X6	Lease payment	(6,000)		3,921	2,079	
	Amortization		(3,921)			3,921
20X7	Lease payment	(6,000)		4,518	1,482	
	Amortization		(4,518)			4,518
20X8	Lease payment	(6,000)		5,207	793	
	Amortization		(5,207)			5,207
Total		(\$30,000)	\$0	\$0	\$10,000	\$20,000

^(a) Calculated based on the capital lease obligation multiplied by the effective interest rate. For example, in year one: $\$20,000 \times 15.24\% = \$3,048$. Interest expense computed under ASC 840 is not impacted by application of the ASC 980-840 guidance.

^(b) Represents the difference between the annual rent expense allowed in rates and the annual interest expense calculated on the capital lease obligation. For example, in year one: $\$6,000 - \$3,048 = \$2,952$. Note that a reporting entity not applying this guidance would recognize \$4,000 of amortization expense annually.

As illustrated in Example 18-4, because of the mechanics of this calculation, the annual amortization of the leased asset is equal to the principal reduction on the lease obligation. REG recognizes annual lease expense of \$6,000. This results in differences from the ASC 840 capital lease model whereby the leased asset and capital lease amortization are reduced at different rates and annual lease expense decreases over the lease term.

18.9.1.1 Considerations for leases of newly-completed plant

In general, the special lease recognition guidance for regulated utilities is not available for a capital lease of newly completed utility plant or a sale-leaseback of newly completed utility plant. The model in ASC 980-840-45-3 results in slower recognition of amortization expense compared with recognition under the general ASC 840 model for capital leases. This deferral of expense results in a “phase-in plan” because allowable costs are shifted to later periods than what would be charged to expense under U.S. GAAP applicable to entities in general. Capitalization of costs associated with a new phase-in plan is not permitted under U.S. GAAP. Accordingly, for a lease of a newly-completed plant, a regulated utility should recognize the leased asset amortization on a straight-line basis rather than following the decelerated method permitted under ASC 980-840. Additionally, if the regulator has not allowed a return on the leased asset or amounts being deferred for collection, this would be considered a disallowance and should be accounted for as such.

In some cases, a regulated utility may have a sale-leaseback transaction that is not part of a phase-in plan. ASC 980-840-25-1 through 25-3 as well as ASC 980-840-35-1 and 35-2 provide guidance for such sale-leaseback transactions.

18.10 Intercompany plant sales

U.S. GAAP provides general guidance for the transfer or sale of assets among parties under common control. However, there are unique considerations in accounting for these types of transactions if the recipient of the assets or business is a regulated utility.

BC Appendix discusses factors to consider in determining whether a transaction qualifies as a transfer among parties under common control and the related accounting guidance. This section addresses common control transactions involving a regulated utility.

18.10.1 Common control transactions with a regulated utility

Generally, the sale of a plant between entities under common control is accounted for in accordance with ASC 805-50, with any excess paid over the parent's historical basis in the asset being recognized in equity. Transactions between entities under common control that involve the transfer of a business ordinarily will result in a change in reporting entity for the receiving entity, which requires retrospective combination for all periods presented as if the combination had been in effect since inception of common control. However, when a plant is sold from a non-regulated entity to a regulated entity under common control, ASC 980-810-45 provides the relevant accounting guidance, which states that profit on sales to regulated affiliates should not be eliminated provided that the sales price is reasonable and it is probable that revenue approximately equal to the sales price will result from the regulated entity's use of the product. Accordingly, a gain on sale from a non-regulated affiliate to a regulated affiliate may be recognized within the consolidated financial statements if the regulator allows recovery of the acquisition cost.

In most cases, the sale of a plant by a non-regulated affiliate to a regulated affiliate is considered the transfer of a business; however, because such plant does not become part of the regulated affiliate's rate base until the transaction is approved by the regulator, retrospective combination for all periods presented as if the combination had been in effect since inception of common control is generally not appropriate. Such sales by a non-regulated affiliate to a regulated affiliate are generally accounted for on a prospective basis subsequent to the transfer of the business.

Similarly, a regulated entity may be required to record a loss if a regulator disallows the full sales price in connection with the acquisition of a plant by a regulated entity from a non-regulated affiliate. Under this circumstance, the regulated utility should account for the disallowed cost of the acquired plant in accordance with ASC 980-360-35-12, which states "When it becomes probable that part of the cost of a recently-completed plant will be disallowed for rate-making purposes and a reasonable estimate of the amount of the disallowance can be made, the estimated amount of the probable disallowance shall be deducted from the reported cost of the plant and recognized as a loss." As noted in UP 18.7.2, we believe it is reasonable to consider "recently-completed plant" to include utility plant or an addition to utility plant which has been placed in service but has not yet been through an initial rate case. Accordingly, it is appropriate to consider disallowances of plant acquired by a

regulated entity in the context of ASC 980-360-35-12 and recognize a loss in accordance with this guidance.

18.10.2 *Intercompany sales of plant to a non-regulated entity*

Unlike a sale of plant from a non-regulated entity to a regulated entity, ASC 980 does not provide specific guidance for situations in which a regulated entity sells a plant or an interest in a plant to a non-regulated entity under common control. Accordingly, the plant sales from a regulated entity to a non-regulated entity are subject to the guidance for transactions between entities under common control included in ASC 850-50. When accounting for such transactions in the regulated entity's financial statements, given the effect of the regulatory environment, the regulated entity would generally record a regulatory asset or liability for the difference between the net book value of the plant and the cash received (assuming approval of such treatment by the utility's regulator) in the period in which the transaction occurred, with an offsetting amount recognized in the income statement.

Chapter 19:
Regulated operations:
income taxes

19.1 Chapter overview

Regulated utilities that apply ASC 980 are not exempt from the requirements of ASC 740, *Income Taxes*. However, for regulated utilities, the interaction between application of income tax accounting, compliance with the Internal Revenue Code (IRC), and the regulatory process creates unique challenges. This chapter addresses common income tax accounting issues for regulated utilities.

19.2 Impact of regulation

ASC 980 provides specific guidance on accounting for the effects of rate regulation on income taxes.

ASC 980-740-25-1

For regulated entities that meet the criteria for application of paragraph 980-10-15-2, this Subtopic specifically:

- a. Prohibits net-of-tax accounting and reporting
- b. Requires recognition of a deferred tax liability for tax benefits that are flowed through to customers when temporary differences originate and for the equity component of the allowance for funds used during construction
- c. Requires adjustment of a deferred tax liability or asset for an enacted change in tax laws or rates.

ASC 980-740-25-2

If, as a result of an action by a regulator, it is probable that the future increase or decrease in taxes payable for (b) and (c) in the preceding paragraph will be recovered from or returned to customers through future rates, an asset or liability shall be recognized for that probable future revenue or reduction in future revenue pursuant to paragraphs 980-340-25-1 and 980-405-25-1. That asset or liability also shall be a temporary difference for which a deferred tax liability or asset shall be recognized.

Traditional ratemaking allows regulated utilities the ability to recover their operating costs and to earn a return on their investment in rate base (utility plant). Current and deferred income tax expenses are a component of the allowable operating costs considered in the ratemaking process, and there are a number of situations in which ratemaking may affect the accounting for income taxes. Examples include:

- The application of the flow-through method for temporary differences (UP 19.2.1)
- Capitalization and subsequent amortization of the equity component of the allowance for funds used during construction (UP 19.2.2)
- Changes in income tax rates (UP 19.2.3)

- The income tax effects of deferred or unamortized investment tax credits (UP 19.2.4)
- Normalization (UP 19.3)

19.2.1 Flow-through

Flow-through occurs when the regulator excludes deferred income tax expense or benefit from recoverable costs when determining income tax expense for ratemaking. In other words, customer rates are based on current tax expense with future income tax benefits and charges “flowed through” to customers. Because ASC 740 requires deferred tax assets and liabilities to be recognized for temporary differences that arise between income tax reporting and financial reporting, regulated utilities may need to record regulatory assets or liabilities in accordance with ASC 980-740-25-1(b).

Flow-through results in a reduction of current and total income tax expense in the period that a deductible temporary difference arises and an increase in current and total income tax expense in the period that the temporary difference reverses. For example, when temporary differences associated with repairs deductions arise, under flow-through, current income tax expense will reflect the repairs deduction, and rates charged to customers will be based on the lower income tax expense (no deferred tax expense is recorded). In the future when the repair expenditures begin to reverse, future revenues of the regulated utility will increase (i.e., rates charged to customers will increase to recover the higher current income tax expense over the period of reversal).

Under ASC 740, deferred tax assets or liabilities are required to be recognized on temporary differences, whether flowed through or not. If it is probable that the deferred tax liabilities or assets recognized in connection with the flow-through of temporary differences will be recovered from, or returned to, customers through future rates, the regulated utility should recognize a corresponding regulatory asset or liability pursuant to paragraphs ASC 980-340-25-1 and ASC 980-405-25-1, respectively. The regulatory asset or liability is “grossed up” for additional deferred income taxes to reflect the fact that future decreases or increases in revenues will also affect future income taxes payable or refundable. The gross-up is required because the initial regulatory asset recorded in this situation is, itself, a temporary difference.

Regulated utilities are required to follow IRC normalization rules for certain accelerated deductions and credits. Tax penalties can be imposed if the regulated utility fails to normalize (e.g., if a regulator requires flow-through for the items required to be normalized; see UP 19.3). In addition, differences may exist between what a regulated utility is required to flow through for federal tax purposes and what it is required to flow through for state tax purposes (e.g., certain normalization requirements may not extend to state-related deductions).

19.2.1.1 Application example — flow-through of a temporary difference

Example 19-1 illustrates the accounting for flow-through of a temporary difference.

EXAMPLE 19-1**Accounting for the flow-through of a temporary difference**

Rosemary Electric & Gas Company, a regulated utility, incurs \$100,000 of repairs that are capitalized for accounting purposes but are deductible for income tax purposes, resulting in a basis difference of \$100,000 in year one. The repair cost will be depreciated over 10 years for accounting purposes. The income tax rate is 35%. A deferred income tax liability of \$35,000 is recognized for this temporary difference. The regulatory jurisdiction in which REG operates requires the book/tax differences for repair costs to be flowed through to customers. REG determines that future recovery of the temporary difference is probable.

How should REG account for the temporary difference?

Analysis

REG would record a deferred tax liability (with the offset recorded as an increase to regulatory assets) in year one for the temporary difference that has flowed through to ratepayers as follows (amounts in thousands):

Year		Regulatory asset	Deferred tax liability	Income tax expense	Income tax payable
1	To record the current tax benefit of the flow-through difference (\$100 x 35%)			(\$35)	\$35
	To establish the deferred tax liability and regulatory asset to reflect the effects of rate regulation (\$100 x 35%)	\$35	(\$35)		
	To record the gross-up of the regulatory asset $(\$35 / (1 - 35\%) - \$35)$	19	(19)		
	TOTAL	\$54	(\$54)	(\$35)	\$35

The total deferred tax liability is equal to the \$100,000 difference between the book basis of the asset (\$100,000) and the tax basis of the asset (\$0) plus the “grossed-up” regulatory asset multiplied by the tax rate $[(\$100,000 + \$54,000) \times 35\%]$.

In practice, regulated utilities often record one journal entry on a net basis by calculating the grossed-up regulatory asset and deferred income tax liability (i.e., the total of \$54,000). In each of the next 10 years, current income tax expense would increase by \$3,500 (\$35,000/10 years) and the deferred tax liability and regulatory asset would be reduced by \$5,400 (\$3,500 grossed-up) to reflect the reversal of the temporary difference.

The flow-through regulatory asset represents the amount of future revenue and the related increase in future tax expense that will be recovered from ratepayers when the temporary difference reverses. As part of its tax and regulatory accounting records, a regulated utility should be able to demonstrate when the reversal will occur and that the temporary difference was flowed through when it originated for each flow-through-related balance.

19.2.2 Equity portion of allowance for funds used during construction

The accounting for the equity component of allowance for funds used during construction (AFUDC) is similar to flow-through and results in a deferred tax liability in accordance with ASC 980-740-25-1(b). It also creates a related regulatory asset if the corresponding future revenue is probable of recovery. Equity AFUDC capitalized for accounting and regulatory purposes is a component of construction cost and is depreciated once the utility plant is placed in service (i.e., it gives rise to accounting basis). However, for income tax purposes, neither the amount originally capitalized for accounting purposes nor the subsequent depreciation of that amount enters into the determination of taxable income. Because equity AFUDC is not capitalized into utility plant for tax purposes (i.e., it does not give rise to a tax basis), the book basis of utility plant will exceed the tax basis of utility plant by the capitalized equity AFUDC amount.

Under ASC 740, a deferred income tax liability is required for this temporary difference. However, regulators typically permit recovery of the equity AFUDC through depreciation without an income tax effect. Therefore, equity AFUDC capitalized for accounting purposes results in the recognition of a deferred tax liability and a “grossed-up” regulatory asset. The gross regulatory asset represents probable future revenue related to the recovery of future income taxes related to the equity AFUDC temporary difference. ASC 980-740-55-8 through 55-11 provide an example of the accounting for the income tax effects of the equity component of AFUDC. The mechanics of accounting for the tax effects of equity AFUDC are similar to those for the flow-through temporary difference illustrated in Example 19-1.

19.2.3 Changes in tax rates

ASC 740 requires deferred income tax assets and liabilities to be adjusted for the effect of a change in enacted tax rates. Regulated utilities likewise are required to adjust deferred income tax assets and liabilities for changes in tax rates or laws, pursuant to ASC 980-740-25-1(c).

A regulated utility may have unique considerations when income tax rates are changed. A regulator may require a regulated utility to pass the effect of reduced income tax rates on to customers as savings over future periods, or it may permit the utility to charge customers for the effect of increased income tax rates. As a result, changes in enacted tax rates may result in a direct adjustment of previously recorded income tax-related regulatory assets or liabilities (see UP 19.2.3.2 for further information on changes related to normalized differences for which regulatory assets and liabilities were not previously recorded). Furthermore, Section 203(e) of the Tax Reform Act of 1986 (TRA) provided a normalization requirement for the excess deferred income taxes created by the TRA’s accelerated depreciation-related tax rate changes. These rules required that the excess deferred taxes be used to reduce customer rates over the lives of the related property. No such Internal Revenue Service (IRS) requirements exist for deferred income taxes related to other temporary differences (see UP 19.3.2.4).

Depending on the regulatory requirements, the impact of remeasuring deferred income taxes as a result of an enacted tax rate change may:

- Reduce or increase the amount of income tax expense the regulated utility would otherwise recover in the period of change
- Reduce or increase income tax expense to be recovered over the reversal period of the temporary differences to which the expenses relate

19.2.3.1 *Application example – change in tax rates*

Example 19-2 illustrates the accounting for the effect of a change in tax rates when the regulator requires or allows the change to be considered in the ratemaking process in the period of the change.

EXAMPLE 19-2

Effect of a change in tax rates on a regulatory asset

Assume the same facts as in Example 19-1. However, the income tax rate changes to 30% on day 1 of the second year and the regulator requires that REG reduce rates charged to ratepayers (over the reversal period of the temporary difference) for the effects of the tax rate change.

How should REG account for the change in tax rate?

Analysis

Current income tax expense would be reduced to reflect the change in the income tax rate. The original regulatory asset and related deferred income tax liability would be adjusted as follows (amounts in thousands):

Year		Regulatory asset	Deferred tax liability
1	Beginning balance	\$54	(\$54)
2	To adjust the regulatory asset and deferred income tax liability for the change in enacted tax rate ($\$100 \times 30\%$) / (1 - 30%) = \$43	(11)	11
TOTAL		\$43	(\$43)

The total deferred tax liability is equal to the \$100,000 difference between the book basis of the asset (\$100,000) and the tax basis of the asset (\$0), plus the regulatory asset, multiplied by the new tax rate: $(\$100,000 + \$43,000) \times 30\%$.

19.2.3.2 *Changes in tax rates when a regulatory asset was not originally recorded*

In some cases, a regulated utility with deferred income tax liabilities does not record a corresponding regulatory asset (e.g., this will be the case when a regulated utility is not required to flow through some or all temporary differences). Although a

regulatory asset or liability was not originally recorded for a deferred tax balance, the regulated utility may be eligible to recover or be required to refund amounts related to a tax rate change over a future period. As required by ASC 740, existing deferred income tax assets or liabilities are to be adjusted for changes in tax rates and allocated to continuing operations. However, if it is probable that the effect of the change in income tax rates will be recovered or refunded in future rates, the regulated utility should record a regulatory asset or liability instead of an increase or decrease to deferred income tax expense.

Application example – changes in tax rates

Example 19-3 illustrates the accounting for the change in tax rate when no regulatory asset was recorded originally.

EXAMPLE 19-3

Effect of a change in tax rates when a regulatory asset was not originally recorded

Rosemary Electric & Gas Company (REG) constructs a utility plant with a book basis of \$400,000 and a tax basis of \$300,000. It records a deferred tax liability for the temporary difference between its accounting basis and tax basis based on its tax rate of 35%. No regulatory asset is recorded for temporary differences in year 1 because the deferred tax provision is included in the ratemaking process.

In year 2, the tax rate changes from 35% to 30%, resulting in a change in the deferred tax liability. REG expects that it will have to return the impact of the change in income tax rates to its customers, through a reduction in future rates together with the tax benefit of that reduction.

How should REG account for the temporary difference?

Analysis

In year 2 when the tax rate changes, REG would reduce its deferred tax liability to an amount based on the new 30% income tax rate.

REG would record the following journal entries (amounts in thousands):

Year		Regulatory liability	Deferred tax liability	Deferred tax provision
1	Establish deferred tax liability for temporary difference between book and tax basis (($\$400 - \300) \times 35%)		(\$35)	\$35
2	Record impact of change in tax rates and related regulatory liability ($\$35 - \30)	(\$5)	5	
	Record gross-up of regulatory liability (($\$35 - \30) / (1 - 30%)) - \$5	(2)	2	
	TOTAL	(\$7)	(\$28)	\$35

In this example, as the temporary difference reverses, the reversal would be at the tax rate originally used to establish the deferred tax liability (35%).

19.2.4 *Investment tax credits*

Investment tax credits are current year reductions in income taxes payable (with unused amounts eligible for carryover) for qualifying property additions. Historically, accounting for ITCs followed the guidance now codified as ASC 740-10-25-45 through 25-46 and ASC 740-10-45-26 through 45-28.

ASC 740-10-25-46

While it shall be considered preferable for the allowable investment credit to be reflected in net income over the productive life of acquired property (the deferral method), treating the credit as a reduction of federal income taxes of the year in which the credit arises (the flow-through method) is also acceptable.

Most regulated utilities account for ITCs using the deferral method because that method more closely mirrors the ratemaking treatment needed to meet normalization requirements. However, the “gross-up” deferral method is also acceptable (see TX 3.2.3). Normalization requires that ITCs related to utility plant be “shared” between ratepayers and shareholders, typically over the book life of the related property (see UP 19.3.2.1). Under ASC 740, ITCs that are accounted for under the deferral method are considered a reduction in the book basis of the asset. This reduction creates a temporary difference resulting from lower taxable income when the book basis of those assets is recovered in future years. The accumulated deferred ITC temporary difference gives rise to a deferred tax asset and a “grossed-up” regulatory liability that represents the probable future reduction in revenue required for future income taxes as the deferred ITC is amortized. See TX 3.2.3 for further information on accounting for credits and other tax incentives.

In the United States, the American Recovery and Reinvestment Act of 2009 (ARRA) allowed taxpayers to choose a cash grant in lieu of an ITC for certain qualifying energy-related facilities or property that have begun construction prior to the end of 2012. As a result, certain ITCs may be accounted for differently from the traditional ITC accounting model. See UP 16 for further information on the accounting for government incentives, including grants and ITCs received pursuant to Section 1603 of ARRA.

Question 19-1

Can a regulated utility aggregate all plant-related temporary differences into one temporary difference?

PwC response

Generally, yes. The difference between the tax basis and book basis of utility plant generally comprises multiple temporary differences, which may be caused by factors including:

- Accelerated depreciation
- Repairs capitalized for book but deductible for tax
- Debt or equity AFUDC
- Certain overhead expenses that have different book and tax treatment
- Certain deferred ITC balances
- Removal costs
- Contributions in aid of construction

The transition rules for FASB Statement No. 109, *Accounting for Income Taxes*, provided that when it was impracticable to determine the components, it was permissible to combine all plant-related temporary differences into a single plant-related temporary difference. However, this approach can be challenging for regulated utilities. Regulatory assets arising from temporary differences should be recorded only if they are probable of recovery under ASC 980-340-25-1. Making the probable determination may be difficult if the regulated utility does not individually track and evaluate the temporary differences.

19.2.4.1 **Application example – accounting for ITC using the deferral method**

Example 19-4 illustrates the accounting for traditional ITC using the deferral method.

EXAMPLE 19-4

Accounting for the income tax effects of ITCs

Rosemary Electric & Gas Company (REG) generates \$100,000 of ITCs in year one. REG's income tax rate is 35%. REG follows the deferral method of accounting for ITCs and determines that future recovery in rates of temporary basis differences is probable.

How should REG account for the temporary difference using the deferral method?

Analysis

REG should record the following journal entries (amounts in thousands):

Year		Unamortized ITC	Deferred tax asset	Income tax payable	Regulatory liability	Income tax expense
1	Record the reduction in current year expense for the ITC			\$100		(\$100)
	Defer the impact of ITC	(\$100)				100
	Record impact of regulatory accounting (100 x 35%) / (1 - 35%)		\$54		(\$54)	
		(\$100)	\$54	\$100	(\$54)	\$ -

Under this method, REG would amortize the unamortized ITC as a reduction to income tax expense over the estimated depreciable life of the related property used for accounting purposes. See UP 19.3.2.1 for information on certain ITC normalization considerations.

19.3 *Normalization*

Normalization is integral to accounting for income taxes in a regulated environment and arises from IRC guidance on the ratemaking approach. Normalization is a method of ensuring that regulated utilities benefit from the various tax law provisions that were designed to encourage capital expenditures.

For example, accelerated depreciation and ITCs are intended to encourage capital expenditures, not to subsidize customers' utility costs. However, because these deductions and credits reduce cash income taxes, the tax component of the cost of providing services would be lower, and thus, the rates charged to customers would be lower if these benefits were immediately provided to customers. This lowers the regulated utility's revenues in the short term. Normalization protects revenues from the effects of lower rates, and allows regulated utilities and customers to share the benefits of accelerated depreciation and investment tax credits.

Under the normalization rules, for a regulated utility to claim accelerated deductions on its tax return, its regulator must require that the tax savings be "normalized" over the life of the property. This means that income tax expense in the ratemaking process will be computed as if depreciation was recorded on a straight-line basis, rather than through an immediate reduction in rates (as is the case under flow-through). In other words, the regulated utility determines the income taxes recognized for regulatory purposes based on the amount of depreciation recognized for financial reporting and regulatory purposes. Because regulators allow the recovery of book amounts on an accrual basis, the regulated utility should also consider the related income tax effects of such cost recovery on an accrual basis.

Under the normalization rules, the regulated utility records a reserve against rate base for the difference between the income tax allowance determined in this manner and the amount of income taxes actually paid (i.e., accumulated deferred income taxes or ADIT). That reserve is then drawn down as, for example, the accelerated depreciation benefits reverse in later years. This reduction to rate base for ADIT provides ratepayers with the benefit of the accelerated depreciation deduction received by the regulated utility (which is effectively an interest free loan from the government).

19.3.1 *Normalization violations*

If a regulated utility fails to normalize its accelerated deductions when required pursuant to the IRC, it may result in the loss of the income tax deductions or recapture of tax credits. A normalization violation with respect to accelerated depreciation may result in the loss of the right to claim the tax deduction on assets in service as of the date of the violation, as well as for future additions. This would apply to all property, plant, and equipment, not just those that cause the violation. A

normalization violation associated with ITCs could result in the recapture of the greater of (1) all ITCs previously claimed in open years or (2) the unamortized ITC balance as of the violation date. See UP 19.3.2.1 for further information on normalization of ITCs.

Examples of normalization violations include:

- Repayment of excess deferred income taxes too quickly (see UP 19.3.2.4 for information on excess deferred income taxes)
- When a regulator provides for normalization that does not fully comply with the normalization rules (e.g., calculating the amount of deferred income tax expense using a shorter period than the depreciable life of the plant)

If a regulated utility believes it could potentially have a violation of the normalization provisions, it should consider whether an accrual for unrecognized tax benefits in accordance with ASC 740 is needed or whether it should seek a private letter ruling from the IRS.

19.3.2 Normalization considerations

Certain tax items may have unique normalization considerations.

19.3.2.1 Normalization of investment tax credits

Similar to accelerated depreciation, before the ITC normalization rules were in effect, certain regulators required utilities to immediately flow through the tax benefits of ITCs to customers in the form of lower rates. Although immediate flow-through of ITCs continued to be prohibited, normalization rules were enacted whereby regulated utilities could choose between two ratemaking methods. These methods were established in an attempt to achieve a better balancing of the benefit of ITCs between regulated utilities and their customers:

□ *Option one*

A reduction of rate base for accumulated deferred ITCs, provided the rate base reduction would be restored, “not less rapidly than ratably” over the book life of the property, without any cost-of-service effect. Under this option, the customers benefit from the lower return requirements that result from reducing the rate base by the unamortized balance of the deferred ITCs, and the shareholders benefit from the regulated utility’s receipt of the ITC funds over the life of the related property.

□ *Option two*

A reduction of cost-of-service by a ratable portion of the allowable tax credits, determined by the asset’s book life, provided that accumulated deferred credits are not also used to reduce rate base. Under this option, the customers receive the direct cost-of-service benefit of the funds related to the ITCs over the life of the related property and the shareholders receive the time value of the deferred ITCs.

Regulated utilities may follow either of these options; however, the option selected is irrevocable. Violations of the normalization requirements may result in the recapture of previously-claimed ITCs. See UP 19.3.1 for further information on the accounting implications of a normalization violation.

19.3.2.2 Normalization of repairs

Historically, regulated utilities have generally treated repairs and maintenance expense for tax accounting purposes in the same manner as for accounting and regulatory purposes. However, in recent years many regulated utilities have filed with the IRS for a change in their tax accounting method, to define the applicable unit of property differently for tax purposes in determining the amount of deductible repairs. This has led to tax deductions being larger than book expense because repairs and maintenance expenses are being treated as an immediate tax deduction, rather than as a capitalizable item.

Although the IRS has provided guidance in this area,¹ this change in tax accounting method has created some complexities for regulated utilities because regulators may require flow-through of repairs deductions that would have previously been normalized. The application of these changes has resulted in regulated utilities having to recalculate the tax bases of their assets as though they had always been using this new method (i.e., as if they had always treated repairs and maintenance as a repairs deduction rather than a capitalized asset).² Once the tax basis is recalculated, the regulated utility makes a “net adjustment” that is recognized as the current repairs deduction in the current tax return. This net adjustment comprises two components: (1) tax deductions related to repairs and (2) an offset related to tax depreciation on assets taken to date that would not have been permitted if the expenditures had been deducted rather than capitalized and depreciated.

From an accounting standpoint, the change in tax accounting method for repairs and maintenance has created some complexity because accelerated deductions are required to be normalized whereas repairs deductions are not. Therefore, where a regulated utility may have previously normalized its accelerated deductions related to repairs, the regulator may now require flow-through of the repairs deduction. A question arises as to how much of the repairs and maintenance amount can be flowed through to ratepayers.

Application example – normalization

Example 19-5 illustrates the impact of these changes and the related normalization considerations.

¹ See the IRS’ Revenue Procedures 2011-42, 2011-43, and 2013-24.

² An IRC § 481(a) adjustment.

EXAMPLE 19-5**Calculating the repairs deduction**

Rosemary Electric & Gas Company (REG) purchased a 20-year asset in 20X1 for a cost of \$100,000. For tax purposes, the asset is being depreciated using the modified accelerated cost recovery system (MACRS). The asset was depreciated 17% at the end of 20X3 under MACRS. In 20X4, REG applies the most recent IRS repairs guidance and reclassifies the original \$100,000 expenditure as a repair expense.

What is the allowable repair deduction in 20x4?

Analysis

The 20X4 deduction related to reclassifying this expenditure as a repair for tax would be \$83,000. The deduction is computed as follows: \$100,000 deduction minus \$17,000 already recovered through depreciation ($\$100,000 \times 17\%$). The remaining \$83,000 of basis could be recovered through an accelerated repairs deduction in 20X4, rather than over future periods through MACRS depreciation.

REG would convert the recovery of the \$100,000 from a normalized book/tax difference to flow-through treatment. In such cases, REG would determine whether to (1) reverse the normalized basis difference created by the previous accelerated depreciation (i.e., reverse the \$17,000 of normalized temporary basis difference and now flow through the tax effect of all \$100,000 repairs expense) or (2) flow through only the additional deductions from the tax method change and leave the normalized deferred taxes in place (i.e., leave the \$17,000 as a normalized temporary basis difference and flow through only the tax effect of the remaining \$83,000).

Regulated utilities should evaluate the normalization rules in performing this evaluation; regulators could potentially view flow-through of the entire amount of repairs (\$100,000 in this example) as a normalization violation.

19.3.2.3 Normalization of contributions in aid of construction

Regulated utilities often receive contributions in aid of construction (CIAC) from developers or other entities to defray the costs of extending existing facilities into a new service area or of making other system changes. Regulated utilities generally treat nonrefundable CIAC received by water utilities as nontaxable, if certain requirements are met. However, electric and gas utilities may consider CIAC taxable in certain circumstances. The determination of whether CIAC is taxable will typically require the regulated utility to analyze its facts and circumstances surrounding the receipt of the CIAC. For accounting and ratemaking purposes, electric utilities generally treat CIAC as a reduction of utility plant construction costs; therefore, it is not included in rate base. As a result, future depreciation is reduced by the amount of the CIAC.

When CIAC is nontaxable, there are no differences between book and tax to be considered. However, when CIAC is taxable, the different book and tax treatment results in a deductible temporary difference (deferred tax benefit) and the regulated utility will need to consider the normalization implications. The normalization

requirements vary depending on whether the regulator allows the regulated utility to gross up the amount collected from the developer or other entity for the taxes to be paid on the CIAC. If a regulated utility is permitted to collect a grossed-up amount from the developer (thereby insulating ratepayers from the income tax effects), then it is not required to normalize the temporary difference related to CIAC. However, if the regulator precludes a regulated utility from collecting taxes on CIAC, there is no amount to flow through to ratepayers and the temporary difference is normalized.

Application example – taxable CIAC

Example 19-6 illustrates the accounting for taxable CIAC.

EXAMPLE 19-6

Accounting for taxable contributions in aid of construction

Rosemary Electric & Gas Company (REG) is constructing a \$150,000 substation to service a new development and receives \$100,000 of CIAC from the developer. REG concludes that the CIAC will be taxable at 35%. Therefore, although the accounting basis of the asset will be \$50,000, the tax basis will be \$150,000, creating a temporary basis difference of \$100,000.

Should REG normalize depreciation for the substation?

Analysis

If the regulator does not allow REG to recover the tax on CIAC from the developer, the regulated utility would be required to normalize and record a deferred tax asset of \$35,000 ($\$100,000 \times 35\%$). However, if the regulator allows REG to recover the tax from the developer and requires that such recovery be flowed through to ratepayers, the regulated utility would record a regulatory liability representing the gross-up.

19.3.2.4 Normalization of excess deferred income taxes

Normalization rules also apply to excess deferred income taxes on depreciation-related temporary differences arising from a reduction in corporate tax rates that went into effect in 1986. The rules require regulated utilities to normalize and amortize the impacts of the TRA rate change. Regulated utilities commonly apply an approach called the average rate assumption method (ARAM), which was mandated as a result of the TRA. Under ARAM, the reversal of the excess deferred income taxes cannot occur more rapidly than would occur over the remaining regulatory lives of the assets as the temporary differences related to the assets reverse.

Reducing rates charged to ratepayers relating to excess accumulated deferred income taxes in the wrong period may constitute a violation of the normalization requirements. However, not all regulated utilities maintain their depreciation records in a manner that will readily allow them to apply ARAM. For example, some regulated utilities may not have the records to compute depreciation consistent with ARAM. To address this situation, the IRS allows an alternative method for reducing the excess deferred taxes, referred to as the “Reverse South Georgia method.” Under the Reverse

South Georgia method, regulated utilities determine reversals based on the composite rate and begin immediately, in contrast to the ARAM method, which delays recognition until the book-tax depreciation timing differences reverse. However, the Reverse South Georgia method is not permissible if the regulated utility uses a composite method of depreciation and has the records to determine the reversal period of the book/tax differences to which the excess deferred income taxes relate.

19.3.2.5 ASC 740-10 and ratemaking

As explained in UP 19.3, ADIT generally reduces rate base. However, this calculation can be complicated by the presence of income tax reserves for uncertain tax positions under ASC 740-10 (formerly FIN 48, *Accounting for Uncertainty in Income Taxes — an interpretation of FASB Statement No.109*). Under the concepts illustrated in ASC 740-10-55-110 through ASC 740-10-55-112, in which a temporary difference would normally create a deferred tax liability, but the temporary difference is created in whole or in part through an uncertain tax position, the regulated utility should separate the liability recorded between (1) the deferred tax liability based on the sustainable book/tax difference on each reporting date and (2) the liability for the uncertain tax position.

Regulators sometimes provide different answers with respect to how the uncertain tax position liability should be treated for rate base purposes. In some jurisdictions, such as the FERC, the regulated utility generally reclasses the uncertain tax position liability back to a deferred tax liability and treats it as if it were a deferred tax liability. However, this approach has been criticized by certain regulatory experts as being contrary to the logic of including the deferred tax liability as a rate base offset. As explained in UP 19.3, deferred tax liabilities are typically considered as a rate base offset because the utility is deemed to receive an interest free loan from the government for accelerated deductions such as depreciation. If the accelerated deduction is uncertain, however, then it is likely that the utility is not receiving the loan interest free. If it is not ultimately able to sustain the deduction, it will have to pay the tax and any accrued interest for the deduction back to the government.

Based on this logic, some other regulatory jurisdictions have excluded uncertain tax position liabilities from deferred tax liabilities as a rate base offset. However, these jurisdictions have typically built a regulatory tracker mechanism onto the uncertain tax position liabilities. The trackers allow for the rate base exclusion for uncertain tax position liabilities, but if the utility ultimately sustains all or part of the deduction subject to the liability, the utility must compensate the ratepayers for the time value of money through a return on capital.

19.4 Income taxes in interim periods

ASC 740-270-30 prescribes an estimated annual effective tax rate (AETR) approach for calculating a tax provision for interim periods, with certain exceptions. However, in some cases regulated utilities estimate the income tax provision in interim periods using a discrete method. Prior to the Codification, the FASB addressed this practice in FASB Interpretation No. 18, *Accounting for Income Taxes in Interim Periods — an interpretation of APB Opinion No. 28* (FIN 18).

FIN 18, paragraph 78

A number of respondents stated that the proposed Interpretation should not apply to regulated industries. Some respondents noted that the Addendum to APB Opinion No. 2 may provide an exemption from the Interpretation for certain enterprises in regulated industries. The Board is aware that differing applications of the Addendum exist in practice and has not addressed that issue.

Because no further guidance has been issued on this matter, the continued use of the discrete method by regulated utilities applying ASC 980 is acceptable. However, a change to this method by reporting entities that already apply the AETR approach would not be a preferable change in accounting. There are exceptional circumstances in which a regulated utility should exclude a jurisdiction from applying the AETR (e.g., when a reliable estimate of ordinary income cannot be made). Such circumstances are unusual and judgment is required. See TX 17 for further information on calculating income taxes for interim periods.

19.5 *Separate company reporting*

Public utility holding companies often have regulated and unregulated subsidiaries that issue stand-alone financial statements. The regulated subsidiaries may be separate SEC registrants and, thus, are required to report on a stand-alone basis.

ASC 740-10-30-27 requires allocation of consolidated current and deferred income taxes among members of a group, but does not specify the use of any single allocation method. However, the method adopted should be systematic, rational, and consistent with the broad principles established by ASC 740. There are two approaches regulated utilities commonly use to compute tax expense in their stand-alone financial statements: (1) the separate return method and (2) the benefits-for-loss modification of the separate return method. See TX 14.1 for information and guidance on applying these methods.

Regulators often approve intercompany tax sharing arrangements and may scrutinize the regulated utility's allocation of consolidated income tax expense items. Some regulators may require utilities to use an overall effective tax rate for the entire affiliated group filing a consolidated return. Others may require that losses in the consolidated group be allocated to the entities that have gains, reducing either directly or indirectly the income tax component of rates for those entities when determining revenue requirements. Reporting entities should carefully consider whether to follow the allocation arrangement adopted for ratemaking as a number of these methods may not meet the broad principles of ASC 740. In addition, the SEC staff has expressed a preference that public companies use the separate return method.

If there are differences between the method of allocation under a tax sharing arrangement approved by the regulator and what would be allowable under ASC 740, the regulated utility would treat the resulting difference in amounts the regulated utility paid or received under the tax sharing arrangement as a dividend or capital

contribution. See TX 14 for information on allocating income taxes of a consolidated group.

19.6 *Net operating losses attributable to accelerated depreciation*

In recent years, the IRS has permitted certain amounts of accelerated tax depreciation (i.e., bonus depreciation) whereby 50 percent, or as much as 100 percent, of a property's cost may be deducted in the year placed in service. Utilities and power companies commonly elect bonus depreciation. By accelerating income tax deductions, bonus depreciation may give rise to net operating losses. ASC 740 requires that a valuation allowance be recorded against deferred tax assets that are not likely to be realized. Potential sources of taxable income that can be used to support realization include loss carrybacks and carryforwards, the reversal of existing deferred tax liabilities, tax planning strategies, and future projections. See TX 5 for information on evaluating the realizability of net operating losses and other deferred tax assets.

For regulated utilities, it is important to note that net operating loss-related deferred tax assets arising from accelerated depreciation must offset the related deferred tax liabilities for ratemaking purposes to avoid a potential normalization violation.

Chapter 20:
Regulated operations:
business combinations

20.1 Chapter overview

ASC 805, *Business Combinations*, contains the guidance on accounting for business combinations. It requires the acquirer to apply the acquisition method to the transaction, which involves recording identifiable assets acquired, liabilities assumed, and any noncontrolling interests at their acquisition-date fair values¹ (with fair value measured in accordance with the principles of ASC 820, *Fair Value Measurement*). A business combination that involves a regulated utility may have certain unique issues as a result of the impact of regulation. This chapter focuses on these issues, including:

- Measuring the fair value of assets and liabilities arising from, or subject to, regulation
- Determining when regulatory offset of fair value adjustments is appropriate
- Accounting for merger credits
- Postacquisition accounting for goodwill

See UP 8 for information on other matters related to business combination accounting specific to utilities and power companies, including issues associated with the acquisition of power purchase agreements and other contractual arrangements. This chapter and UP 8 supplement PwC's *Business combinations and noncontrolling interests* guide with business combination accounting issues unique to the utility and power industry.

20.2 Application of ASC 980 after a business combination

When a regulated utility is involved in a business combination, it is generally required to seek approval for the transaction from its regulator. When a regulator approves a business combination involving a regulated utility, it may result in changes to customer rates, recovery mechanisms, or other facets of the regulatory relationship. Although we would expect such situations to be infrequent, reporting entities should consider whether any of the regulator's requirements stemming from the business combination affect the applicability of regulatory accounting.

20.3 Fair value of regulated assets and liabilities

All assets acquired and liabilities assumed in a business combination should be recorded at their acquisition-date fair values, except as specifically stated in ASC 805. Regulation can impact the fair value of utility plant assets and it may be appropriate to offset certain fair value adjustments with regulatory assets and liabilities. However, regulation does not override other U.S. GAAP. ASC 805 and ASC 820 should be

¹ Limited exceptions to the fair value measurement principles for acquired assets and liabilities are provided for in the Standards. See BC 2 for further information.

applied when accounting for a business combination. The interaction of regulation and fair value in a business combination is summarized in Figure 20-1.

Figure 20-1
Accounting for a regulated utility business combination

Component	Fair value considerations	Regulatory considerations
Utility plant assets (UP 20.3.1)	<ul style="list-style-type: none"> □ Regulation is a characteristic of utility plant assets and as it would be considered by market participants, its effects should be incorporated in the valuation 	No separate regulatory accounting
Regulatory assets and liabilities (UP 20.3.2)	<ul style="list-style-type: none"> □ Assets that are earning higher or lower returns than market participants require for similar assets and liabilities should be adjusted to reflect fair value (i.e., a market participant's required return may differ from the current allowed rate of return) □ Nonperformance risk should be incorporated in the fair value measurement of liabilities 	Not applicable; the asset or liability being recorded is the regulatory asset or liability itself
Intangible assets and liabilities, including contractual rights and obligations (UP 20.3.3)	<ul style="list-style-type: none"> □ Identifiable intangible assets acquired should be recognized separately from goodwill □ All contracts should be recorded at their acquisition-date fair values (e.g., derivatives, executory contracts, land rights, leases, and others) □ Some licenses may be valued as part of related plant assets 	Regulatory offset may be appropriate in certain circumstances, depending on ratemaking and specific pass-through mechanisms
Liabilities (including long-term debt) (UP 20.3.4 and UP 20.3.5)	<ul style="list-style-type: none"> □ All liabilities, including long-term debt, should be recorded at their acquisition-date fair values (except for pensions and tax liabilities, which follow specific guidance in ASC 805) □ Fair value should incorporate the reporting entity's own credit and current market conditions 	Regulatory offset may be appropriate in certain circumstances

The following sections address accounting considerations specific to regulated utility acquisitions.

Question 20-1

Is it appropriate for a reporting entity to record a regulatory asset or liability as an offset to working capital assets acquired and liabilities assumed in a business combination?

PwC response

Generally, no. In accordance with ASC 805, working capital assets and liabilities are required to be measured at fair value in a business combination. Typically, a regulated utility recovers working capital items through its general cost of service. As a result, we would not expect a reporting entity to record a regulatory asset or liability to offset fair value adjustments to working capital items. Amounts included in a utility's general cost of service would not have the direct cause and effect relationship between rates and costs to qualify for regulatory offset.

See UP 20.3.3.1 for further information on evaluating regulatory offset. See BC 7.5.1 for further information on the valuation of working capital items when applying the acquisition method.

20.3.1 Utility plant assets

Utility plant assets are assets that are included in "rate base," that is, assets on which the regulated utility is permitted to earn a return that is included in rates charged to customers. The environment in which a utility's plant assets are managed, as well as the impact of regulation on future cash flows, has a significant effect on the fair value. ASC 820 requires the use of market participant perspectives in measuring fair value and the resulting valuation should exclude any characteristics of an asset arising from its association with a specific entity. However, ASC 820-10-35-2B acknowledges that the use of an asset may be limited by restrictions to which it is subject.

ASC 820-10-35-2B

A fair value measurement is for a particular asset or liability. Therefore, when measuring fair value a reporting entity shall take into account the characteristics of the asset or liability if market participants would take those characteristics into account when pricing the asset or liability at the measurement date. Such characteristics include, for example, the following:

- a. The condition and location of the asset
- b. Restrictions, if any, on the sale or use of the asset.

Regulation is viewed as being a characteristic (restriction) of the asset and the impact of regulation is considered a fundamental input to measuring the fair value of utility plant assets in a business combination. See UP 20.3.1.3 for other factors that should be considered in measuring the fair value of utility plant assets.

20.3.1.1 **Regulation is a characteristic of utility plant assets**

ASC 820-10-35-10B describes factors that should be considered in measuring the fair value of a nonfinancial asset, indicating that the highest and best use of the asset should be based on potential uses that are “physically possible,” “legally permissible,” and “financially feasible.” The currently-accepted framework for utility plant asset valuations is based on the conclusion that use of utility property outside of regulation is neither legally permissible nor financially feasible because of the public interest in the assets.

Physically possible

Regulated utilities may view legal restrictions on the physical use of utility plant assets created by regulation (see below) as similar to an easement or zoning restriction. Although the asset is within the jurisdiction of a regulator, it is essentially zoned for the single purpose of serving customers of regulated utilities and yields a regulated return. As with an easement, the regulated utility may pay to have the public-use requirement removed (i.e., by return of all or a portion of any gain to customers), but that obligation impacts the realizable value of the asset. Similar to an easement, this leads to a conclusion that a market participant would consider the impact of regulation when valuing the asset.

Legally permissible

State utility commissions and regulators grant a type of monopolistic status to regulated utilities, while retaining some legal control over utility operations to protect the public interest. Under this regulatory compact, regulated utilities agree to rate regulation and accept a “duty to serve,” which includes agreement to serve all who seek service in the territory and to provide safe and reliable service at fair and reasonable rates. Furthermore, the utility’s shareholders receive a stable return, which lowers the return on investment necessary to attract capital. However, in exchange, the shareholders are subject to the requirement that the regulated assets of the regulated utility must be operated for the benefit of the ratepayers and the regulator’s approval is required for significant transactions.

The unique relationship between a public utility, its regulator, and its customers was first established in 1877 in connection with the *Munn v. Illinois* case. Munn and Scott, owners of a grain elevator, challenged the right of the state of Illinois to regulate their business. The U.S. Supreme Court found that “when private property is devoted to a public use, it is subject to public regulation.” Furthermore, the court ruled that:

When, therefore, one devotes his property to a use in which the public has an interest, he, in effect, grants to the public an interest in that use, and must submit to be controlled by the public for the common good, to the extent of the interest he has thus created.

This decision highlights the public interest in the individual property of the regulated utility and indicates that use of that property is controlled for the common good. Regulated utility assets are limited to use for public purposes, and the legal obligation arising from regulation directly restricts the use of an asset as “utility property.” In

addition, regulated utilities often are required to obtain certificates of convenience for significant asset acquisitions, which serve to formally notify a regulator of intent to construct or purchase assets and to gain approval as to the need for the asset and intended use. These requirements further support direct linkage of regulation to the individual asset.

Financially feasible

In the context of a public-use asset that cannot be sold without the regulator's approval, it is not feasible to realize the potential value of the asset outside of the rate-regulated environment. The regulator would either deny the sale or require the regulated utility to refund the gain to the ratepayers. As such, a market participant would be expected to determine the fair value of a utility asset based on retaining the asset for regulated operations and earning a regulated rate of return.

Other considerations

The FASB's approach to accounting by regulated entities provides helpful guidance when considering the fair value of utility plant assets in a business combination. The FASB previously recognized that regulation may impact the economics of transactions such that it should affect the application of U.S. GAAP. Rate-regulated accounting guidance was issued in recognition of the potentially pervasive impact of regulation on a regulated utility. Prior to the Codification, the FASB acknowledged that regulation may result in a benefit or detriment to a regulated utility, and that rate actions of the regulator may change the value of an asset to an enterprise in FAS 71.

FAS 71, paragraph 75

The Board concluded that, for general-purpose financial reporting, the principal economic effect of the regulatory process is to provide assurance of the existence of an asset or evidence of the diminution or elimination of the recoverability of an asset. *The regulator's rate actions affect the regulated enterprise's probable future benefits or lack thereof.* Thus, an enterprise should capitalize a cost if it is probable that future revenue approximately equal to the cost will result through the rate-making process. *(emphasis added)*

Incorporating the effects of regulation in the valuation of the individual assets of a regulated utility is thus consistent with the FASB's conclusion.

Question 20-2

Is there an acceptable alternative view that regulation is an attribute of the reporting entity and should be excluded when measuring the fair value of utility plant assets?

PwC response

Generally, no. At the time the guidance in ASC 805 was initially promulgated by the FASB, there was significant industry debate as to whether regulation should be considered an attribute of the reporting entity owning the asset or a characteristic of

the asset itself. Because ASC 820 requires a market participant view of fair value, a conclusion that regulation is an attribute of the reporting entity and not a characteristic of the individual assets would lead to the conclusion that the effects of regulation generally should not be incorporated in the valuation of utility plant assets. However, there is strong support for the view that regulation is a characteristic of the asset and that its effects should be incorporated in the valuation of utility plant assets. This conclusion is consistent with recent industry practice. Furthermore, the SEC staff has reviewed the accounting for several mergers that occurred since the FASB adopted ASC 805. The SEC staff supported the view that regulation is a characteristic of the asset and should be incorporated into the valuation of utility plant assets.

There may be circumstances when a reporting entity's measurement of the fair value of utility plant assets should also incorporate potential uses outside of the regulated environment (see UP 20.3.1.2). However, we would not expect a reporting entity to fully exclude the impact of regulation in its valuation of regulated utility plant assets.

20.3.1.2 *Highest and best use for utility plant assets acquired in a business combination*

ASC 820 requires reporting entities to determine fair value from the perspective of a market participant. In most cases, the "expected use" of regulated assets will be in a regulated environment. However, in certain cases, a market participant may determine that using the assets outside of a regulated environment achieves its highest and best use. In those circumstances, the regulated utility should evaluate potential alternative uses by a market participant when determining the asset's fair value.

For example, a business combination may include the acquisition of a regulated power plant located near a liquid trading point. The plant may be strategically suited to merchant operations and there may be interested buyers outside of the regulated environment. In such cases, when measuring the plant's fair value, the reporting entity should consider the highest and best use for the asset and the expected regulatory treatment of gains resulting from sales of assets in that jurisdiction. If the acquirer may reasonably expect to retain a portion of any gain on sale, the alternative use as well as a reasonable estimate of expected outcome should be considered in the valuation.

20.3.1.3 *Considerations in valuing utility plant assets*

As discussed in UP 20.3.1.1, regulated utilities should incorporate the impact of regulation in the valuation of utility plant assets. However, the reporting entity should not assume that this automatically results in a carryover of the predecessor basis (i.e., historical cost) because regulation is just one aspect of a fair value measurement. The acquirer should also consider whether there are other factors that would impact fair value in accordance with ASC 805 and ASC 820. For example, a market participant's required rate of return is a key input in the determination of fair value. Regulated utilities should also incorporate differences in the risk-adjusted rate required by market participants and the current earned return on the assets in the valuation.

Utility plant assets are typically valued using an income approach. Factors that reporting entities should consider in performing the valuation include:

- The nature and use of the utility plant assets
- How the regulated utility's earned return compares to the rate of return for similar assets subject to regulation in the exit market
- Whether the regulated entity is over- or under-earning on its utility plant assets and the timing for any potential catch-up through the ratemaking process (i.e., regulatory lag)

A market participant may be willing to pay more for the utility plant assets if the regulated utility is earning a higher than market rate for similar regulated assets. Conversely, it may require a lower purchase price if the regulated utility is under-earning or earning a return that is below market. Further, any mechanism for the utility to be "trued-up," or expectation that the regulated return will be adjusted to a rate based on current market conditions in a near-term rate case, may reduce the impact of the purchase price adjustment that the market participant would otherwise require.

The valuation of utility plant assets may also be impacted by any uncertainty inherent in the cash flows (e.g., construction in progress that is still subject to regulatory review may not be assured of recovery). See UP 20.3.2.2 and UP 20.3.2.3 for further information on the determination of an appropriate risk-adjusted discount rate and incorporation of uncertainty risk in a fair value measurement, respectively. Although this discussion is in the context of fair value measurements of regulatory assets, the guidance also applies to the valuation of utility plant assets.

Question 20-3

In an acquisition of a regulated utility, is it ever appropriate to carryover utility plant assets at the acquiree's basis?

PwC response

It depends. An evaluation would be performed to determine a market participant's view of fair value of the regulated utility plant assets. Given the regulated nature of and fixed return associated with utility plant, it may be appropriate to carryover the acquiree's basis. The acquiree's basis may be reflective of the amount a market participant would be willing to pay for the assets in an arm's length transaction.

20.3.2 Regulatory assets and liabilities

When regulatory assets and liabilities are measured at fair value in a business combination, the determination of fair value should follow the concepts in ASC 820. That is, fair value is the price that would be (1) received to sell an asset or (2) paid to transfer a liability between market participants (i.e., an exit price). Figure 20-2 summarizes key considerations in measuring the fair value of regulatory assets and liabilities.

Figure 20-2
Fair value measurement of regulatory assets and liabilities

Determine unit of account	The unit of account is the individual regulatory asset or liability.
Evaluate valuation premise	We would generally expect valuation at the individual asset or liability level.
Assess principal market	There is no principal market for the sale of regulatory assets or transfer of regulatory liabilities. There have been some limited sales of regulatory assets (e.g., stranded costs, storm costs) through securitization transactions; however, this type of transaction involves additional legal and other requirements that are not characteristics of typical regulatory assets.
In the absence of a principal market, determine the most advantageous market	Reporting entities generally need to develop a hypothetical market to measure the fair value of regulatory assets and liabilities.
Determine valuation technique	Reporting entities should consider one or more of the following alternative valuation techniques: <ul style="list-style-type: none"> □ Income approach — a discounted cash flow approach is likely the most appropriate method for valuing regulatory assets and liabilities, incorporating inputs from available market transactions as appropriate. □ Market approach — any available information from securitizations of regulatory assets may provide inputs in developing an estimate of fair value, although the different characteristics of the securitized assets may render those inputs less meaningful. □ Cost approach — a cost approach may be appropriate in certain limited circumstances, for example, for newly-constructed or under-construction assets; however, because a regulatory asset's value is represented by the future cash flow stream, regulated utilities more commonly use the income approach.
Determine amounts of key inputs	Reporting entities typically consider the following inputs for use in the valuation model: <ul style="list-style-type: none"> □ Expected amount and timing of cash flows (UP 20.3.2.1) □ Discount rate (UP 20.3.2.2) □ Other adjustments due to uncertainty (risk premium) (UP 20.3.2.3 and 20.3.2.4) □ Nonperformance risk (UP 20.3.2.5)

In general, we would expect regulated utilities to measure the fair value of individual regulatory assets and liabilities using an income approach. This is also the approach typically used for utility plant assets. ASC 820-10-55-3F through 55-20 provides further guidance on the application of this approach, including the factors that should be incorporated in the valuation.

20.3.2.1 *Amount and timing of cash flows*

A key component of the measurement of fair value when using an income approach is the expectation about possible variations in the amount and timing of cash flows. Although some regulatory assets and liabilities may have minimal or no uncertainty about the timing or amount expected to be paid or received, others may involve significant inherent uncertainty. For example, the timing of collection may vary for a regulatory asset collected through a rate surcharge dependent on the level of sales. In other cases, such as revenue subject to refund, there may be uncertainty about the amount that ultimately will be paid or received prior to the time of the final rate order. Depending on the amount and range of uncertainty, it may be appropriate to develop various probability-weighted scenarios using an expected present value technique. See ASC 820-10-55-13 and FV 4.4.3 for further information.

20.3.2.2 *Risk-adjusted discount rate*

In measuring the fair value of regulatory or utility plant balances, a reporting entity should select an appropriate risk-adjusted discount rate. In developing the appropriate rate, the reporting entity should consider the nature of the regulated cash flows and the rates demanded by market participants as of the measurement date. The specific facts and circumstances will influence whether an adjustment to the rate being earned is required.

Where no return is currently allowed or the earned rate differs from the risk-adjusted discount rate, the reporting entity should adjust the carrying value of the regulatory asset or liability when applying the acquisition method.

20.3.2.3 *Regulatory assets: uncertainty risk*

The measurement of the fair value of an asset should incorporate consideration of the uncertainty inherent in its future cash flows (a risk adjustment). In evaluating the uncertainty risk for a regulatory or utility plant asset, the reporting entity should assess the overall probability of the asset's recovery. A market participant would demand a discount for the uncertainty related to the recovery of the asset. The level of uncertainty in the future cash flows—and thus the related adjustment—may vary, depending on the nature of the specific asset and its inherent collection risk. For example, if a regulated utility has a specific rate order for a regulatory asset and the amounts are either “collected” through amortization against the utility's revenue requirement or through a rate surcharge or specified rate, the reporting entity may be able to support recording no adjustment for uncertainty risk. However, other regulatory assets may have more collection uncertainty. For example, a regulatory asset for which recovery is deemed to be probable, but for which an order has not yet

been received, may require an additional risk premium in measuring fair value at the acquisition date.

20.3.2.4 Regulatory liabilities: uncertainty risk

ASC 820 also provides guidance for the fair value measurement of liabilities and the incorporation of adjustments for risk. The types of risk adjustments to include vary depending on whether the liability is held by another party as an asset. Regulatory liabilities are not held by other parties as an asset; therefore, the guidance in ASC 820-10-35-16H through 35-16L should be applied.

Excerpt from ASC 820-10-35-16J

When using a present value technique to measure the fair value of a liability that is not held by another party as an asset..., a reporting entity shall, among other things, estimate the future cash outflows that market participants would expect to incur in fulfilling the obligation. Those future cash outflows shall include market participants' expectations about the costs of fulfilling the obligation and the compensation that a market participant would require for taking on the obligation. Such compensation includes the return that a market participant would require for the following:

- a. Undertaking the activity (that is, the value of fulfilling the obligation—for example, by using resources that could be used for other activities)
- b. Assuming the risk associated with the obligation (that is, a risk premium that reflects the risk that the actual cash outflows might differ from the expected cash outflows; see paragraph 820-10-35-16L).

Similar to the uncertainty adjustment discussed in UP 20.3.2.3, an adjustment for uncertainty risk related to a regulatory liability can be incorporated either by adjusting the cash flows or by adjusting the discount rate. As with regulatory assets, when developing the risk premium for regulatory liabilities, regulated utilities should consider what a market participant would demand as compensation for the risk being assumed to fulfill that regulatory liability. For example, this could include a probability-weighted estimate of the amounts ultimately required to be returned to ratepayers.

20.3.2.5 Regulatory liabilities: nonperformance risk

ASC 820 also requires incorporation of nonperformance risk in the fair value measurement of a liability.

Excerpt from ASC 820-10-35-18

When measuring the fair value of a liability, a reporting entity shall take into account the effect of its credit risk (credit standing) and any other factors that might influence the likelihood that the obligation will or will not be fulfilled. That effect may differ depending on the liability, for example:

- a. Whether the liability is an obligation to deliver cash (a financial liability) or an obligation to deliver goods or services (a nonfinancial liability)
- b. The terms of credit enhancements related to the liability, if any.

Credit risk is often the largest component of nonperformance risk. The nonperformance risk associated with a regulatory liability is based on the regulated utility's own credit and any other factors that may impact repayment. Many argue that there is no risk of nonperformance because the regulator requires full repayment of all regulatory liabilities. However, nonperformance risk, by definition, includes the market price an investor will demand as compensation for the risk of default. Risk of default is equally applicable to regulatory liabilities as it is to conventional debt obligations. Therefore, in measuring the fair value of regulatory liabilities, the reporting entity should incorporate its own risk of nonperformance. See FV 8 for information about how to measure nonperformance risk.

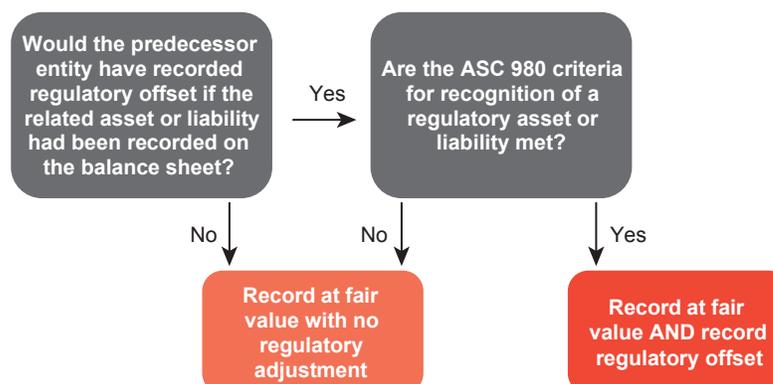
20.3.3 *Intangible assets and liabilities*

ASC 805 requires recognition of all identifiable assets acquired and liabilities assumed in a business combination, including contractual rights and obligations. Accounting for such items in a regulatory environment typically includes addressing certain issues involving the valuation of intangibles in a business combination, as further discussed in this section.

20.3.3.1 *Recognition of offsetting regulatory assets and liabilities*

The effects of regulation are typically not incorporated in the initial fair value measurement of intangible assets such as contractual rights or obligations, including power purchase contracts, emission allowances, and similar items. However, similar to utility plant assets, regulated customers often have a specific interest in contract rights and obligations or other intangible assets held by a regulated utility. Therefore, a question arises as to when it is appropriate to record an offsetting regulatory asset or liability (regulatory offset) when applying the acquisition method. Figure 20-3 illustrates the considerations in determining whether regulatory offset should be recorded when applying the acquisition method.

Figure 20-3
Determining when regulatory offset should be recorded



Certain contractual rights and obligations or other intangible assets that were not previously recorded in the acquiree’s financial statements may be recorded as a result of a business combination. These rights and obligations may include an associated customer “interest” or “obligation” that was not previously reflected as a regulatory asset or liability (e.g., an out-of-the money power purchase agreement that does not meet the definition of a derivative, but was executed for the benefit of customers and will be collected through rates). The customer interest or obligation may have been present prior to the business combination from transactions that the predecessor initiated as part of providing service to its customer base, but regulatory accounting may not have been triggered because the related asset or liability was not recognized in accordance with applicable U.S. GAAP.

In determining whether a previously-unrecognized regulatory asset or liability should be recorded on the acquisition date, considerations include:

- *Would the predecessor entity have recorded regulatory offset if the related asset or liability had been recorded on the balance sheet?*

For example, does the regulated utility have a direct cost pass-through or other specific recovery mechanism associated with the asset or liability? If there is direct cause and effect between assets or liabilities recorded and regulatory recovery from, or return to, customers, it would be appropriate to record the impact of regulation. However, if there is no direct linkage between cost and recovery (e.g., amounts are recovered through the general rate case process or are not recoverable at all), we would not expect a reporting entity to recognize the impact of regulation when applying the acquisition method.

- *Did the business combination affect the regulated utility’s obligation to return gains, or its right to recover losses from customers? Are the ASC 980 requirements still met?*

For example, as part of the business combination, the acquirer may have agreed not to seek customer recovery of certain “off-market” contracts. As such, it would not be appropriate to record a regulatory asset to offset the contractual liability recorded when applying the acquisition method. The regulated utility should

review the rate order approving the acquisition to ensure the impacts of the agreement are properly reflected in recording the business combination.

The regulated utility should record regulatory offset if the right to recovery or obligation to refund existed with the predecessor entity, and the predecessor would have recorded a regulatory asset or liability if the related contractual right or obligation had been recognized.

Example 20-1 provides an example of recording regulatory offset.

EXAMPLE 20-1

Recognition of regulatory offset when applying the acquisition method

M&H Holding Company (M&H) acquires all of the stock of Rosemary Electric & Gas Company (REG) on April 2, 20X4. In accordance with the requirements of ASC 805, the acquired assets and liabilities assumed in the business combination are measured at fair value as of the acquisition date.

REG has a power purchase agreement with a third-party power generator valued at \$40 million as of the acquisition date. Prior to the acquisition, the contract was accounted for under the normal purchases and normal sales scope exception and was not recognized at fair value in the accounting records. As part of its accounting for the acquisition of REG, M&H will record a contract intangible asset related to this agreement. REG has a power cost adjustment mechanism and recovers all prudent power costs from customers. Prior to the acquisition, regulatory accounting was not applied because the contract was not recognized on the balance sheet.

Should M&H record a regulatory liability to offset the contract intangible asset recorded as part of its acquisition of REG?

Analysis

Yes, M&H should record a regulatory liability because the benefit from this contract must be returned to customers. Further, REG would have recorded a regulatory liability if the power contract had been recorded on the balance sheet prior to the acquisition. Therefore, in applying the acquisition method, M&H will also recognize a related regulatory liability.

See UP 8.4 for information on the post-acquisition accounting for the intangible asset.

20.3.3.2 Contracts with specific prohibition against transfer or resale

Contractual rights or licenses held by a regulated utility may have specific prohibitions against transfer to a third party. For example, a regulated utility may have a right to receive power from a hydroelectric project operated by a government entity, but is prohibited from transferring these rights to another party. The fair value for this type of contract may be measured by comparing the cost of the power from the facility to the cost of market power. However, if the contract cannot be transferred, the fair value cannot be monetized. Similarly, regulated utilities may hold Federal Energy

Regulatory Commission or other operating licenses that are not legally transferrable. Therefore, a question arises as to whether these transfer restrictions affect the recognition of the rights or licenses in acquisition accounting.

ASC 805 concludes that transfer restrictions do not impact the requirement to record such contractual rights or obligations.

Excerpt from ASC 805-20-55-2

Paragraph 805-20-25-10 establishes that an intangible asset is identifiable if it meets either the separability criterion or the contractual-legal criterion described in the definition of identifiable. An intangible asset that meets the contractual-legal criterion is identifiable even if the asset is not transferable or separable from the acquiree or from other rights and obligations. For example: (a) An acquiree leases a manufacturing facility under an operating lease that has terms that are favorable relative to market terms. The lease terms explicitly prohibit transfer of the lease (through either sale or sublease). The amount by which the lease terms are favorable compared with the pricing of current market transactions for the same or similar items is an intangible asset that meets the contractual-legal criterion for recognition separately from goodwill, even though the acquirer cannot sell or otherwise transfer the lease contract.

Therefore, as explicitly discussed in the example in ASC 805, a contract right or intangible asset should be recognized regardless of any transfer restrictions. See FV 4.8 for further information on evaluating the impact of asset transfer restrictions on fair value measurements.

20.3.4 Liabilities

Regulated utilities typically have numerous long-term liabilities, such as long-term debt, asset retirement obligations, and environmental accruals. All liabilities should be measured at fair value on the measurement date, with the exception of pension and tax liabilities, which are subject to special provisions in ASC 805. Similar to contractual rights or other intangibles, the impact of regulation should not be directly incorporated into the valuation of long-term liabilities. However, regulatory offset may be appropriate if certain criteria are met. See UP 20.3.3.1 for information on recognizing regulatory offset.

Example 20-2 illustrates the evaluation of regulatory offset for liabilities.

EXAMPLE 20-2

Recognition of regulatory assets to offset fair value adjustments for liabilities

Pine Tree Electric Company (PTE) owns all of the stock of Rosemary Electric & Gas Company (REG) and Cypress Water & Power Company (CW&P). REG and CW&P are located in different states and are subject to different utility commissions. PTE is acquired by M&H Holding Company (M&H) on April 2, 20X4. In accordance with the requirements of ASC 805, all of the assets and liabilities acquired in the business combination are measured at fair value as of the acquisition date.

Both REG and CW&P have significant environmental remediation liabilities; however, they have different forms of regulatory recovery:

- REG has an environmental cost recovery mechanism in place whereby it recovers the cost of remediating specified environmental sites previously reviewed and approved by its regulator. Its existing environmental liability is offset by a related regulatory asset.
- CW&P recovers its environmental costs through its general rate cases. The amount included in the periodic rate cases is based on an average of actual cash expenditures for environmental remediation over the preceding three years.

M&H plans to make certain adjustments to the measurement of the environmental liabilities as part of applying the acquisition method.

Should M&H also record an adjustment to its regulatory assets to offset the remeasurement of the environmental liabilities?

Analysis

In this case, REG has a specific mechanism to recover its environmental costs and, prior to the acquisition, had recorded a regulatory asset to reflect the unrecovered portion of the costs incurred to date. Management of M&H therefore concludes that it is appropriate to adjust REG's environmental-related regulatory asset when applying the acquisition method. In contrast, as CW&P recovers its environmental costs through the general rate case process, with no specific recovery mechanism, the ASC 980-340-25-1 criteria are not met and any adjustments to the environmental liabilities recorded when applying the acquisition method should not be offset by a regulatory asset.

20.3.5 Long-term debt

This section discusses the considerations related to the accounting for long-term debt in the acquisition of a regulated utility.

20.3.5.1 Recognition of an offsetting regulatory asset or liability

Long-term debt presents unique considerations in evaluating whether regulatory offset should be recorded, as a direct cause-and-effect relationship between recovery of debt costs and rates is often difficult to establish. Regulated utilities generally recover the cost of long-term debt as part of a general rate case or other proceeding that establishes the utility's authorized rate of return. The regulated utility may establish the authorized rate of return annually or as part of the general rate cycle, depending on the jurisdiction and the individual utility. The utility may determine the authorized rate of return by incorporating the actual cost of the utility's borrowings and capital structure or based on a hypothetical capital structure.

In evaluating whether regulatory offset is appropriate, the regulated utility should consider the rate treatment of debt costs and how interest and other costs are recovered. Factors that would support regulatory offset include:

- Interest and other debt-related costs are considered as a direct input in the ratemaking process
- Regulatory mechanisms directly incorporate interest cost or other debt-related expenses/benefits
- The jurisdiction has a history of direct recovery of gains and losses on debt, amounts related to interest rate swaps, or other debt-related costs

The regulated utility should consider all available evidence in determining whether it is appropriate to offset any debt-related fair value adjustments with a regulatory asset or liability. It may be difficult to support regulatory offset if the regulated utility's cost of capital is determined based on a hypothetical structure, or if there is limited correlation between the cost of debt and amounts recovered through rates.

20.3.5.2 Accounting for other debt-related amounts

All liabilities, including long-term debt, should be measured at fair value as of the acquisition date. The fair value measurement is based on the price the reporting entity would have to pay a third party of comparable credit quality to assume the debt. If no quoted prices are available for the liability (either on its own or when trading as an asset), the reporting entity may measure fair value using projected cash flows, current interest rates, and the risk of nonperformance by the issuer. If a liability (such as long-term debt) is held by another party as an asset, the reporting entity should base the measurement approach on assumptions of that party holding the liability as an asset, in accordance with ASC 820-10-35-16B. In such a transaction, debt issuance costs, premiums, discounts, and related amounts have no continuing relevance as the fair value amount reflects the full value of the debt at the measurement date. Therefore, the fair value measurement should replace all amounts on the balance sheet related to the long-term debt, regardless of whether such amounts are recorded in the long-term debt caption of the acquiree.

For reporting entities in general, this accounting guidance leads to the write-off of all debt-related amounts. However, for regulated utilities, a question arises as to whether certain debt-related amounts may be retained on the balance sheet by the acquirer as regulatory assets. It would be appropriate to record regulatory assets associated with certain debt-related costs if the recognition criteria in ASC 980 are met. We would generally expect the treatment of the debt-related costs to be consistent with the accounting for assumed debt (i.e., if regulatory offset is recorded for debt, it is likely it will also apply to the related debt costs). However, reporting entities should separately evaluate the accounting for debt-related costs. Absent an appropriate basis for their recovery, the regulated utility should not record any regulatory assets or liabilities.

Regulated utilities may also have previously-deferred amounts related to reacquired debt. Gains and losses on reacquired debt are recognized at the time of a debt extinguishment by reporting entities in general, but such amounts are deferred for collection or payment through the rate process by regulated utilities if probable of recovery or return. Because these amounts represent regulatory assets or liabilities that were previously deferred as a result of their regulatory treatment, we believe it would generally be appropriate to continue to defer these amounts when applying the

acquisition method. Reporting entities should consider the guidance in UP 20.3.2 when measuring and recording the fair value of such amounts.

20.3.6 *Preexisting relationships between the acquirer and the acquiree*

ASC 805-10-55-20 and 55-21 discuss relationships between the acquirer and the acquiree that existed prior to the business combination (referred to as preexisting relationships). The acquirer should recognize a gain or loss if a preexisting relationship is effectively settled as part of the business combination.

There may be circumstances when a regulated utility acquired in a business combination has a preexisting relationship with an unregulated component of the acquiring entity (e.g., the acquiree, a regulated utility, has a long-term electric supply agreement with an unregulated generation subsidiary of the acquirer). In such cases, the reporting entity should consider whether the relationship has been “effectively settled” or whether the regulated entity’s asset (or liability) continues to exist. If the contract costs are otherwise recoverable as a component of rates, and the regulator has not addressed termination of the contract, the regulated utility would typically conclude that the relationship has not been effectively settled. Consequently, the reporting entity would record an asset or liability for the fair value of the contract on the acquisition date, and would follow the guidance in UP 20.3.3.1 to assess whether an offsetting regulatory asset or liability should be recorded. Similar considerations apply in evaluating existing relationships between regulated and unregulated subsidiaries of an acquiree.

Example 20-3 illustrates application of the ASC 805 guidance related to preexisting relationships in a regulated utility acquisition.

EXAMPLE 20-3

Accounting for preexisting relationships in a business combination

M&H Holding Company (M&H) acquires all of the stock of Rosemary Electric & Gas Company (REG) on April 2, 20X4. Prior to the acquisition, REG had contracted with M&H’s unregulated generation subsidiary to purchase energy under a 20-year power purchase agreement. REG is permitted to recover 100% of its purchased power costs from ratepayers. At the date of the acquisition, the contract is \$30 million “out-of-the-money” for REG, and \$30 million “in-the-money” for M&H. The business combination does not result in a change to REG’s rate agreement and it will continue to recover 100% of its purchased power costs. Because the contract is “out of the money” for REG at the acquisition date, M&H will record a contract liability as part of its accounting for the acquisition.

As part of its accounting for the acquisition, should M&H record a regulatory asset to offset the contract liability recognized as part of acquisition accounting?

Analysis

Yes. M&H should record a regulatory asset because the costs of the power purchase agreement continue to be recoverable from ratepayers. Further, REG would have

recorded a regulatory asset if the power purchase agreement had been recorded on the balance sheet prior to the acquisition. Therefore, M&H would record the following journal entry when applying the acquisition method (amounts in millions):

Dr Regulatory asset	\$30	
Cr Contract intangible liability		\$30

This accounting is predicated on consistent regulatory treatment before and after the merger. A regulator's requirement to cancel the contract or change the contractual terms as a condition of the merger transaction would impact the accounting conclusion. The regulated utility should evaluate any such changes to determine the appropriate accounting.

20.4 *Merger credits – updated December 2018*

Many regulated utility acquisitions include rate discounts that are negotiated by the acquirer with the regulator as part of obtaining the regulator's support for the transaction (referred to as "merger credits" for purposes of this discussion). As discussed in UP 17.4, merger credits typically do not meet the definition of a regulatory liability or a liability under CON 6. However, a question arises as to whether such amounts should be recognized as a liability when applying the acquisition method.

Question 20-4

Should merger credits be recorded as part of the liabilities assumed in a business combination?

PwC response

No. ASC 805 discusses recognition of assets acquired and liabilities assumed in a business combination.

Excerpt from ASC 805-20-25-3

In addition, to qualify for recognition as part of applying the acquisition method, the identifiable assets acquired and liabilities assumed must be part of what the acquirer and the acquiree (or its former owners) exchanged in the business combination transaction rather than the result of separate transactions.

In accordance with ASC 805-20-25-3, assets and liabilities recognized as part of acquisition accounting should be part of the exchange between the acquirer and the acquiree. Merger credits typically would not be part of the exchange in an acquisition involving a regulated utility (i.e., contingent consideration of the acquirer). Merger credits are more akin to acquisition-related costs, which are expensed as incurred, as they are not negotiated between the buyer and seller but are instead conditions accepted by the seller to obtain regulatory approval. Under this view, merger credits

do not represent a liability to the seller at the acquisition date rather they represent a future reduction of revenues as the credits are issued.

Therefore, as the merger credits are not part of the exchange, no merger credit liability should be recorded as part of the business combination.

20.5 Post-acquisition accounting for goodwill

Goodwill often results from a business combination. ASC 980 specifically addresses the accounting for goodwill by a regulated utility.

ASC 980-350-35-1

Topic 350 states that goodwill shall not be amortized and shall be tested for impairment in accordance with that Subtopic. For rate-making purposes, a regulator may permit an entity to amortize purchased goodwill over a specified period. In other cases, a regulator may direct an entity not to amortize goodwill or to write off goodwill.

ASC 980-350-35-2

If the regulator permits all or a portion of goodwill to be amortized over a specific time period as an allowable cost for rate-making purposes, the regulator's action provides reasonable assurance of the existence of a regulatory asset (see paragraph 980-340-25-1). That regulatory asset would then be amortized for financial reporting purposes over the period during which it will be allowed for rate-making purposes. Otherwise, goodwill shall not be amortized and shall be accounted for in accordance with Topic 350.

Note about ongoing standard setting

At the time of release of this guide, the FASB had an active project on its agenda on accounting for goodwill. Preparers and other users of this publication should continue to monitor the project, and if finalized, evaluate the impact and effective date of the new guidance.

If a regulator allows rate recovery of any amount that would otherwise be recorded as goodwill, consistent with this guidance, such amount should be accounted for and recorded as a regulatory asset. Subsequent measurement of the goodwill-related regulatory asset should follow the guidance in ASC 980-350. For example, if the regulator subsequently disallows the goodwill, or the regulated utility ceases to apply ASC 980, the regulatory asset should be written off.

Separately, it should be noted that ASC 740-10-25-3(d) only exempts nondeductible goodwill amortization from deferred income tax accounting. Deferred income taxes should be recognized for goodwill that is being accounted for as a regulatory asset and amortized.

Question 20-5

Goodwill that is allowable for rate-making purposes is not an incurred cost. Why is it accounted for and recorded as a regulatory asset?

PwC response

Although goodwill is not an incurred cost, ASC 980-350-35-2 specifically states that if goodwill is allowed for rate-making purposes, it should be accounted for as a regulatory asset. The FASB intended that a goodwill-related regulatory asset should be reported and accounted for in the same manner as other regulatory assets. Therefore, goodwill allowed for rate-making purposes should be classified on the balance sheet as a regulatory asset and amortized over the rate-recovery period. Further, subsequent measurement should follow the overall guidance for regulatory assets in ASC 980.

20.5.1 Goodwill impairment

Notwithstanding the guidance provided by ASC 980-350-35-1 and 35-2, regulated utilities are generally not provided with rate recovery of goodwill arising in a business combination. As such, a question may arise as to whether any goodwill recorded in the acquisition is automatically impaired under ASC 350. Impairment of goodwill should be evaluated by each reporting entity based on its specific facts and circumstances. However, in general, we believe that the lack of specific rate recovery does not result in automatic impairment of goodwill, because the goodwill did not arise from a specific regulatory recovery mechanism but rather relates to the economic prospects for the acquiree and other factors.

To test goodwill for impairment, a reporting entity should follow the guidance in ASC 350. ASC 350 requires that an entity assign its goodwill to reporting units and test each reporting unit's goodwill for impairment at least on an annual basis and between annual tests if an event occurs or circumstances change that would more likely than not reduce the fair value of a reporting unit below its carrying amount. The fair value of the reporting unit may differ from its regulated value (amount allowed for recovery by the regulator). Factors that may contribute to the difference between the two values include the regulated utility's regulated return as compared to the return provided by the market, operating synergies, the value of unregulated assets and operations, and the value of other intangible assets. See BC 11.2 and BC 11.4 for further discussion of the identification of reporting units and the allocation of goodwill to those reporting units. See BC 11.5.9.3 and BC 11.5.9.4 for further discussion of impairment testing of goodwill for separate subsidiary financial statements.

Chapter 21:
Presentation and
disclosure

21.1 Chapter overview

This chapter addresses financial statement presentation considerations and disclosure requirements unique or particularly relevant to utilities and power companies.

This chapter should be used as a supplement to U.S. GAAP and the general presentation and disclosure guidance provided by PwC's *Financial statement presentation* guide (FSP) and SEC Volume.

21.2 Leases

Often, leases that arise out of power purchase agreements are operating leases. Presentation and disclosures of operating leases are included in FSP 14. Additionally, as discussed in UP 2 there are certain policy elections to be made regarding whether RECs are output and the interpretation of "fixed" per unit of output. Disclosures should be considered regarding these policy elections.

21.3 Derivatives

The explicit financial statement presentation and disclosure requirements related to derivative contracts can be found in FSP 19.

21.4 Regional transmission organizations

Although there are no explicit reporting requirements, RTOs should consider disclosing elements of transactions that would otherwise be required. For example, if any financial instruments are accounted for as leases or derivatives, the RTO should refer to the disclosure requirements in those areas. In addition, the accounting for the Open Access Transmission Tariff (OATT) may create regulatory assets or liabilities that require certain levels of disclosures (see UP 21.17). In addition, managing transmission assets or investing in the RTO markets create operational and financial risks and uncertainties that reporting entities may believe are significant and should be disclosed.

21.5 Natural gas

Although there are no explicit presentation and disclosure reporting requirements related to natural gas, if a natural gas contract contains a lease or is a derivative there may be specific disclosure requirements that would need to be considered.

21.6 Emission allowances

21.6.1 Presentation

The financial statement presentation of emission allowances generally follows the nature of the reporting entity's activities. Figure 21-1 summarizes considerations for the classification of emission allowances in the income statement and statement of cash flows.

Figure 21-1
Financial statement presentation of emission allowances

Purpose for holding	Balance sheet	Income statement	Statement of cash flows
Held for use	Inventory	Cost of compliance is an operating expense; generally classified as part of operations and maintenance or, alternatively, within fuel expense. Proceeds from sales of excess allowances should be classified as a contra-expense or other income.	Activity should be included in operating cash flows because cost of compliance is an operating expense.
Held for use	Intangible assets	Classification of amortization is the same as emission allowances held for use and classified as inventory.	Activity (i.e., purchases and sales of emission allowances) should be included in investing cash flows because amounts relate to an intangible asset. The amortization of the intangible asset should be reported as a non-cash adjustment to operating cash flows.
Held for sale	Inventory	Sales should typically be classified as part of trading revenue.	Sales should be included in operating cash flows; the activity is in the normal course of business and part of operating income.
Held for use	Plant (existing emissions allowances)	Part of depreciation	Part of depreciation

21.6.2 Disclosure

U.S. GAAP does not include any specific disclosure requirements for emission allowances. However, utilities should provide appropriate disclosures based on how the emission allowances are classified (e.g., if allowances are classified as inventory, any required disclosures for inventory should be included in the financial statements). In addition, utilities should consider the applicability of other disclosures about emission allowances, including:

- Policy regarding whether emission allowances are treated as inventory or intangibles
- Early warning disclosures if there is a possibility of future impairments
- Accounting policy for the recognition of proceeds from the sale of emission allowances
- Gain or loss recognized in connection with vintage year swaps
- Contractual commitments related to the future purchase of emission allowances

For its compliance obligation, the reporting entity should disclose:

- Policy for accounting for its compliance obligation (if applicable)
- Any potential fines and penalties (within the contingencies footnote)

21.7 Renewable energy credits (RECs)

21.7.1 Presentation

The financial statement presentation of RECs generally follows the nature of the utility’s activities.

Figure 21-2 summarizes the presentation alternatives for RECs in the balance sheet, income statement, and statement of cash flows. The classification of activities related to RECs within the financial statements should be supported by the underlying business activities and should be consistently applied.

Figure 21-2
Financial statement presentation of RECs

Purpose for holding	Balance sheet	Income statement	Statement of cash flows
Held for use	Inventory	Cost of compliance is an operating expense; proceeds from sales of excess RECs should be classified as a contra-expense.	Activity should be included in operating cash flows because cost of compliance is an operating expense.
Held for use	Intangible assets	Classification is the same as RECs held for use and classified as “inventory.”	Activity should be included in investing cash flows because amounts relate to an intangible asset.

Purpose for holding	Balance sheet	Income statement	Statement of cash flows
Held for sale	Generally inventory	Sales should generally be classified as part of revenue.	Activity should be included in operating cash flows because the sales are in the normal course of business and part of operating income.
Active buying and selling as part of a trading operation to generate profit	Inventory	Sales should be classified as part of trading revenue; reporting entities should assess the appropriateness of net versus gross presentation.	Activity should be included in operating cash flows because it is in the normal course of business and part of operating income.

21.7.2 Disclosure

U.S. GAAP does not include any specific disclosure requirements for RECs. However, reporting entities should make appropriate disclosures based on how the RECs are classified (e.g., if RECs are classified as inventory, any required disclosures for inventory should be included in the financial statements). In addition, the applicability of other disclosures about RECs should be considered, including:

- Policy regarding whether RECs are treated as output
- Policy regarding whether RECs are treated as inventory or intangibles
- Revenue recognition policies
- Early warning disclosures if there is an anticipation of potential impairments or lower-of-cost-or-market adjustments

The utility should also disclose its policy for accounting for its compliance obligation (if applicable). In addition, any potential fines and penalties should be disclosed within the contingencies footnote.

21.8 Business combinations

There are explicit financial statement presentation and disclosure requirements related to business combinations. Refer to FSP 17 for these considerations.

21.9 Investments in power plant entities

Presentation and disclosure requirements with respect to investments in single power plant entities depend on the nature of the investment. Both investors and single power

plant entities are required by the applicable accounting literature to provide certain disclosures.

21.9.1 Single power plant entities

Many single power plant entities are in the form of limited liability companies. ASC 272-10-45 and 10-50 provide specific and extensive presentation and disclosure requirements for these entities. Refer to FSP 32 for the presentation and disclosure considerations for limited liability companies.

Regardless of the legal form of the single power plant entity, it should determine how to record the funds received from its investors. See discussion in UP 9.3. If it is determined that the entity is issuing financial instruments recognized under the guidance in ASC 480-10-50, these are the required disclosures.

ASC 480-10-50-1

Entities that issue financial instruments recognized under the guidance in Section 480-10-25 shall disclose both of the following:

- a. The nature and terms of the financial instruments
- b. The rights and obligations embodied in those instruments, including both:
 - 1. Settlement alternatives, if any, in the contract
 - 2. The entity that controls the settlement alternatives.

ASC 480-10-50-2

Additionally, for all outstanding financial instruments recognized under the guidance in Section 480-10-25 and for each settlement alternative, issuers shall disclose all of the following:

- a. The amount that would be paid, or the number of shares that would be issued and their fair value, determined under the conditions specified in the contract if the settlement were to occur at the reporting date
- b. How changes in the fair value of the issuer's equity shares would affect those settlement amounts (for example, "the issuer is obligated to issue an additional X shares or pay an additional Y dollars in cash for each \$1 decrease in the fair value of one share")
- c. The maximum amount that the issuer could be required to pay to redeem the instrument by physical settlement, if applicable
- d. The maximum number of shares that could be required to be issued, if applicable
- e. That a contract does not limit the amount that the issuer could be required to pay or the number of shares that the issuer could be required to issue, if applicable

- f. For a forward contract or an option indexed to the issuer's equity shares, all of the following:
1. The forward price or option strike price
 2. The number of issuer's shares to which the contract is indexed
 3. The settlement date or dates of the contract, as applicable.

ASC 480-10-50-3

Paragraph 505-10-50-3 requires additional disclosures for actual issuances and settlements that occurred during the accounting period.

21.9.2 *Investors in single power plant entities*

Investors may record their interests in single power plant entities under one of three models, assuming consolidation is not applicable. These models are equity, debt, or receivables. Each of these models contains specific and unique presentation and disclosure requirements. Refer to FSP 9 and 10 for the presentation and disclosure requirements for equity, FSP 9 for those related to debt, and FSP 8 for receivables.

21.10 *Consolidations: Variable interest entities*

There are explicit financial statement presentation and disclosure requirements related to variable interest entities and potential consolidation of those entities. Refer to FSP 18 for these considerations.

21.11 *Inventory*

There are explicit financial statement presentation and disclosure requirements related to inventory. Refer to FSP 8 for these considerations.

Additionally, questions arise as to whether to present the purchase and subsequent resale of raw materials that are entered in contemplation of each other as gross or net. Example 21-1 addresses this question.

EXAMPLE 21-1

Contemplative transactions

Independent Power Producer (IPP) operates a gas fired generation facility. It procures gas from Supplier A under a fixed price forward contract that is below current market rates. The supply contract has no restrictions on resale. IPP purchases gas from Supplier A under its contract in excess of what it needs for generation. Given the excess in market price above the contract purchase price, IPP has decided to sell its excess gas in the market to a third party.

Should the cost of the excess purchased gas and the proceeds from the resale be presented on a gross or net basis in the financial statements of IPP?

Analysis

The transactions should be presented as net fuel expense in the financial statements. The facts and circumstances in this transaction would indicate that the purchase and sale of the excess gas were entered into in contemplation of one another to reduce the overall fuel cost of the facility. The most analogous accounting literature for this circumstance is found in ASC 845-10, *Purchases and Sales of Inventory with the Same Counterparty*, which indicates that separate transactions should be treated as a single exchange when certain indicators are present. The following table includes a discussion of the indicators.

Indicator	Discussion
Transactions are entered into simultaneously	□ IPP takes delivery of the gas and simultaneously sells it into the market.
Terms of the initial contract are off-market	□ The supply contract is off-market and is an incentive for IPP to enter into an additional contract to realize the benefits of the off-market contract.
The transactions are certain to occur	□ IPP has a firm commitment from Supplier A and there is both the economic incentive and ability to sell into the market.
Purpose of the transaction	□ The transactions are entered into in order to minimize the fuel costs needed to generate the necessary energy.

21.12 *Plant*

There are explicit financial statement presentation and disclosure requirements related to plant. Refer to FSP 8 for these considerations.

Additionally, there are other specific industry considerations as follows.

21.12.1 *Balance sheet classification of interconnection costs*

A developer/owner of a power plant may be required to construct or fund the development of an interconnection to the transmission system, but the transmission system owner may retain ownership of the interconnection. There are alternative acceptable treatments of the asset in these types of arrangements.

Interconnection costs as an intangible asset

Although the developer/owner may have incurred costs related to the construction of interconnection, the actual ownership of the interconnection may be retained by the transmission owner. However, the facility will be granted a right to use the interconnection as part of an interconnection agreement. Accordingly, the developer/owner may classify the asset related to the interconnection as an intangible because the asset is not the underlying physical asset but rather a right to use the asset.

Interconnection costs as part of property, plant, and equipment

An alternative view is that the costs associated with the interconnection are costs of the plant itself. As noted in UP 12, the cost of an asset should include “the costs necessarily incurred to bring it to the condition and location necessary for its intended use.” As the construction of an interconnection is required for a facility to be able to provide its output to the transmission system, costs incurred related the interconnection may be considered as having been incurred in order to bring the facility to the condition necessary for its intended use. Accordingly, interconnection costs may be capitalized within plant costs.

21.12.2 *Statement of cash flows**Construction advances from developers*

Because of the refund obligation, activity related to advances is usually classified as a financing activity in the statement of cash flows.

Major maintenance expense

Major maintenance expense, discussed in UP 12.4.1, should be included in the operating activities section of the statement of cash flows.

The purchase of capital spares, discussed in UP 12.4.2, represents a capital expenditure that should be reflected in the investing activities section of the statement of cash flows.

21.13 *Asset retirement obligations*

There are explicit financial statement presentation and disclosure requirements related to asset retirement obligations. Refer to FSP 11 for these considerations.

21.14 *Nuclear power plants*

The following details the specific considerations relating to the financial statement presentation of nuclear decommissioning trust fund assets.

21.14.1 Balance sheet presentation

Nuclear fuel should be included as a component of property, plant, and equipment. Nuclear fuel in the fabrication and installation phase should be classified as construction work in progress. Leased nuclear fuel that qualifies as a capital lease should be classified as property, plant, and equipment.

Nuclear decommissioning trust fund investments typically will be used to fund future decommissioning of a nuclear facility. Despite their marketability or maturity dates, the purpose for holding them is usually not for short-term use. Therefore, investments held in a nuclear decommissioning trust fund would generally not meet the definition of a current asset in ASC 210-10-45-1, because the investments are not available for current operations. Furthermore, ASC 210-10-45-4(a) excludes certain amounts from current assets.

Excerpt from ASC 210-10-45-4

The concept of the nature of current assets contemplates the exclusion from that classification of such resources as the following:

- a. Cash and claims to cash that are restricted as to withdrawal or use for other than current operations...or are segregated for the liquidation of long-term debts.

Thus, securities held in nuclear decommissioning trust funds should be classified as non-current until such time as the securities are being used to fund decommissioning.

In accordance with ASC 825-10-45-1, any securities being accounted for at fair value under the fair value option should be separated from similar assets and liabilities not carried at fair value through parenthetical disclosure or by presenting two separate line items on the balance sheet. Securities accounted for using the fair value option should not be combined with securities classified as held-to-maturity without parenthetical disclosure.

21.14.2 Income statement presentation

Amounts recorded in the income statement related to nuclear decommissioning trust funds should be recognized as part of other income and expense, not part of operating income. Amounts so classified may include realized gains and losses, impairment losses, and unrealized gains and losses on investments for which the fair value option has been elected. It would not be appropriate to offset trust earnings against charges for asset retirement costs or other operating expenses.

For a regulated utility, any regulatory recovery or refund payable related to the decommissioning trust funds should be recorded as an offset to the amounts recorded in other income and expense.

21.14.3 *Statement of cash flows*

The classification of purchases, sales, and maturities of investments held in nuclear decommissioning trust funds in the statement of cash flows will partially depend on the accounting designation of those securities, as summarized in Figure 21-3.

Figure 21-3

Statement of cash flows — classification of purchases, sales, and maturities of debt and equity securities

Investment classification	Guidance	Statement of cash flows classification
Trading	ASC 320-10-45-11	Purchases, sales, and maturities of trading securities should be classified based on the nature and purpose for which the securities were acquired. In general, we would expect nuclear decommissioning trust fund activity to be presented as part of investing activities.
Available-for-sale and held-to-maturity	ASC 320-10-45-11	Purchases, sales, and maturities of available-for-sale and held-to-maturity securities should be classified as cash flows from investing activities and reported gross for each security classification (i.e., activity related to available-for-sale and held-to-maturity securities should not be combined).
Fair value option	ASC 825-10-45-3	Cash receipts and payments should be classified according to their nature and purpose, as required by ASC 230, <i>Statement of Cash Flows</i> (ASC 230). In general, we would expect nuclear decommissioning trust fund activity to be presented as part of investing activities.

Purchases, sales, and maturities of nuclear decommissioning trust fund securities should not be classified net unless the securities qualify for net reporting pursuant to ASC 230-10-45-8, meaning that turnover is quick, the amounts are large, and the maturities are short. In addition, unrealized gains and losses on nuclear decommissioning trust fund securities that are not reported in accumulated other comprehensive income should be reported as a non-cash adjustment to operating activities in the statement of cash flows.

21.14.4 *Disclosure*

Investments held in nuclear decommissioning trust funds are subject to all of the disclosure requirements in ASC 320 (addressed in FSP 9) and the additional fair value disclosure requirements in ASC 820, including the specific disclosures required for investments accounted for using the fair value option (addressed in FSP 20).

21.15 *Joint plant and similar arrangements*

21.15.1 *Joint plant*

ASC 980-360-S99-1 requires a public utility with an interest in joint plant to disclose the extent of its interests. The disclosure should include a table that presents the following amounts separately for each interest:

- Utility plant in service
- Accumulated depreciation (if available)
- Plant under construction
- The reporting entity's proportionate share in the plant

Information concerning two or more generating plants on the same site may be combined if appropriate (e.g., the level of ownership interests is similar). The disclosure should specifically state that the dollar amounts disclosed represent the participating utility's share in each joint plant and that each participant is responsible for its own financing.

Public utilities should also state that their share of direct expenses is included in the corresponding category of operating expenses in the income statement. Alternatively, the public utility may classify all expenses as part of purchased power; however, in such case, it should disclose the amount included in purchased power as well as the proportionate amounts charged to specific operating expenses in the joint plant's records.

In addition to the requirements in S99-1, public utilities should include the amounts relating to their share of joint plant contracts in the long-term commitments disclosure, as applicable.

21.15.2 *Certain long-term power contracts*

SAB Topic 10.D, *Long-Term Contracts for Purchase of Electric Power*, addresses the presentation and disclosure requirements for a specific type of long-term power purchase arrangement:

Excerpt from SAB Topic 10.D

Under long-term contracts with public utility districts, cooperatives or other organizations, a utility company receives a portion of the output of a production plant constructed and financed by the district or cooperative. The utility has only a nominal or no investment at all in the plant but pays a proportionate part of the plant's costs, including debt service. The contract may be in the form of a sale of a generating plant and its immediate lease back. The utility is obligated to pay certain minimum amounts which cover debt service requirements whether or not the plant is operating.

In evaluating these types of arrangements, reporting entities should assess the potential accounting implications, including the impact of:

- Lease accounting
- Derivative accounting
- Consolidation
- Guarantee obligations associated with the requirement to pay debt service (see PwC's *Accounting and Reporting Manual* 5360.2)

ASC 980-10-S99-1 specifies certain presentation and disclosure requirements for the types of power contracts described above.

As described in Figure 21-4, public utilities should assess whether any contracts within scope provide or are expected to provide more than 5% of current or estimated future system capability as there are additional presentation requirements for such arrangements.

Figure 21-4
SEC presentation and disclosure requirements for certain long-term power contracts

Presentation and disclosure	Requirements
Presentation — all contracts	Cost of power obtained should be included in operating expenses (includes payments made when the plant is not operating)
Disclosure — all contracts	Disclosure should include information about the contract terms and significance: <ul style="list-style-type: none"> □ Date the contract expires □ The share of plant output being purchased □ The estimated annual cost and annual minimum debt service payment required □ The amount of related long-term debt or lease obligations outstanding □ The allocable portion of interest included in expense under such contracts
Presentation and disclosure — contracts that provide or are expected to provide more than 5% of current or estimated future system capability	Significant contracts require additional disclosure in the form of either: <ul style="list-style-type: none"> □ Separate financial statements of the vendor entity □ Recording of the amount of the contract obligation as a liability on the balance sheet with a corresponding asset representing the right to purchase power

21.16 Government incentives

As noted in UP 16, there is no direct U.S. GAAP guidance related to government incentives, so utilities reporting under U.S. GAAP generally apply the IFRS guidance in IAS 20 by analogy.

21.16.1 Balance sheet presentation

IAS 20, paragraph 24, provides flexibility in the balance sheet presentation of grants related to assets, noting that the benefit from a grant should be presented as a basis reduction to the property or separately presented as deferred income. The decision to reduce the basis of the property or to reflect the cash grant as deferred income is an accounting policy election that should be consistently applied and disclosed.

Question 21-1

Is there a preferable method of presenting grants on the balance sheet?

PwC response

No. We have observed that regulated utilities generally present the grants as a basis reduction of utility plant, while it is more common for power companies (nonregulated entities) to classify grants as deferred income. We believe that both methods are acceptable unless the reporting entity concludes that the grant should be accounted for as a regulatory liability (see UP 16.2.3).

Question 21-2

Is it acceptable to adopt different policies for the financial statement presentation of different types of grants? For example, could Section 1603 grants be presented as a reduction of plant assets, while other grants are recorded as deferred income?

PwC response

Generally, no. In some cases, a reporting entity may receive more than one type of grant (e.g., Section 1603 grants, ARRA smart grid grants). In general, we believe that a reporting entity should adopt one consistent policy for the presentation of all asset-based grants. It would be difficult to support more than one policy unless the characteristics of the grants differ significantly (which generally would not be expected among different types of asset-based grants).

A reporting entity may also have more than one subsidiary obtaining government grants. We believe that all entities within a consolidated group should elect and follow a consistent policy for similar government grants. However, there may be circumstances when divergence would be supportable. For example, if a regulated utility subsidiary is required to return the benefit of grants to ratepayers, the regulated utility may be able to support differences between its regulated and unregulated subsidiaries. Reporting entities should ensure a valid basis exists for adopting

different accounting policies for grant classification among subsidiaries, taking into consideration factors such as the differing characteristics or purposes of the grants.

21.16.2 Income statement presentation

Presentation in the other financial statements should follow the balance sheet election. Similarly, the presentation of grants related to income should follow the nature of the grant.

There are different considerations for the income statement presentation of asset grants and income grants.

21.16.2.1 Asset grants

The method selected for balance sheet recognition of a cash grant impacts the presentation in the income statement.

Basis reduction of plant

IAS 20, paragraph 27, states that grants recorded as a basis reduction in the carrying amount of the asset would be recognized over “the life of a depreciable asset as a reduced depreciation expense.”

Deferred income

IAS 20, paragraph 26, states that grants related to assets when the grant is recorded as deferred income should be “recognized in profit or loss on a systematic basis over the useful life of the asset.” IAS 20 does not address income statement classification of grants related to assets that are accounted for as deferred income. Practice under IFRS is to present such amounts as “other operating income,” which is a component of operating profit. Operating profit is not an income statement category under U.S. GAAP.

We believe there are two acceptable income statement classification models for the amortization of grants related to assets that are presented as deferred income in the balance sheet:

- Operating expense – gross presentation: classified as a credit in operating expenses with the amount presented in a separate caption
- Other income – gross presentation: classified as a separate component of other income (either within operating income or as other income and expense)

To be consistent with the balance sheet presentation, amounts classified in operating expenses should generally be presented on a gross basis in the income statement (i.e., not as a reduction of depreciation expense), unless amounts are not material. Reporting entities should disclose their accounting policy election and the amount recognized.

21.16.2.2 *Income grants*

Reporting entities may also receive grants related to research and development programs, experimental technology, or other non-capital expenditures. In addition, some grants, such as smart grid awards, may include components related to capital projects as well as amounts related to operating and maintenance expenditures. Grants related to income should not be recognized until the recognition criteria in IAS 20 are met (see UP 16.2.1) and the related expenses have been incurred.

IAS 20, paragraph 29

Grants related to income are sometimes presented as a credit in the statement of comprehensive income, either separately or under a general heading such as ‘Other income’; alternatively, they are deducted in reporting the related expense.

In accordance with this guidance, we believe reporting entities have the following presentation alternatives in reporting grants related to income:

- Operating expenses — net presentation: amounts received may be offset against the related expense within operating expenses
- Operating expenses — gross presentation: amounts received may be presented in a separate caption within operating expenses
- Other income — gross presentation: amounts received may be presented as a separate component of other income

Although net and gross presentations are both acceptable, disclosure of the gross amount may be necessary to allow users to properly understand the financial statements. The utility should consistently apply the chosen presentation to all grants and in all periods.

Question 21-3

Is it acceptable to include grants as a component of revenue?

PwC response

Generally, no, except as discussed for regulated utilities in UP 16.2.3. CON 6 defines revenue.

CON 6, paragraph 78

Revenues are inflows or other enhancements of assets of an entity or settlements of its liabilities (or a combination of both) from delivering or producing goods, rendering services, or other activities that constitute the entity’s ongoing major or central operations.

Constructing assets or conducting research and development or other activities that are partially funded through government grants would not typically be considered major or central operations for a utility or power company. Furthermore, Section 1603 grants are provided in lieu of tax credits; tax credits are not a revenue item. Therefore, we would generally not expect Section 1603, ARRA grants, or other similar grants to be presented as a component of revenue.

We generally believe that asset grants that are recorded as deferred income on the balance sheet should be presented on a gross basis as a component of operating expense or other income (i.e., not as a reduction of depreciation expense). Income grants should also be presented as a component of operating expense or other income; net presentation within operating expenses may be appropriate depending on the facts and circumstances.

Figure 21-5 summarizes the financial statement presentation alternatives for asset and income grants.

Figure 21-5
Financial statement presentation models for government grants

	Asset grant — basis reduction	Asset grant — deferred income	Income grant
Balance sheet	Basis reduction of property	Deferred income	Not applicable
Income statement	Reduction of depreciation expense	Contra-expense or other income	Contra-expense or other income
Statement of cash flows	Investing cash flow	Operating cash flow	Operating cash flow

21.16.2.3 Regulated utilities

As discussed in UP 16.2.3, in some situations a regulator may decouple a grant from the related asset, providing the regulated utility with full recovery of the underlying asset and requiring that the grant be returned to customers. In such cases, we believe the grant should be treated as a separate unit of accounting, and should be accounted for following the guidance for regulatory liabilities.

Consistent with the guidance in ASC 980-405-25-1(c), the regulated utility should recognize the regulatory liability over the subsequent period during which the grant is returned to ratepayers. The related amortization may be recorded as part of revenue or as an offset to operating expenses.

21.16.3 Statement of cash flows presentation

In determining the cash flow presentation of government grants, reporting entities should initially assess whether gross or net presentation is appropriate. IAS 20, paragraph 28, and ASC 230 both support gross presentation of government grants

received in the statement of cash flows. The timing of the initial expenditure and the receipt of the cash grant frequently occur in different periods. Further, the amounts are often material and may significantly impact cash balances. As such, IAS 20 indicates that such amounts are often presented separate from the related asset activity, even when the amounts are shown as a reduction in the basis of plant in the balance sheet.

Reporting entities should consider the appropriate classification and separate line item reporting of cash and income grants within the statement of cash flows.

21.16.3.1 Asset grants

IAS 20 does not address the cash flow classification of government grants; however, we believe that the balance sheet treatment of grants related to assets also dictates presentation in the statement of cash flows.

The ongoing recognition of deferred income and the amortization of the basis adjustment to plant would both be recognized as a non-cash adjustment to operating cash flows (when the statement of cash flows is prepared using the indirect method) as the amounts are recognized.

Basis reduction of plant

We believe the cash inflow for grants accounted for as a basis reduction of plant should be reflected as an investing activity on the statement of cash flows. This position is based on the definition of investing activities in ASC 230.

Partial definition from ASC 230-10-20

Investing Activities: Investing activities include...acquiring and disposing of debt or equity instruments and property, plant, and equipment and other productive assets, that is, assets held for or used in the production of goods or services by the entity (other than materials that are part of the entity's inventory).

The grant proceeds recorded as a basis reduction of property represent a reduction of costs incurred for the purpose of constructing property, plant, and equipment; therefore, we believe classification in investing activities in the statement of cash flows is the most appropriate classification.

For Section 1603 grants, there is an alternative argument that the grants should be presented as part of operating cash flows, given that it is an election made in lieu of taking an investment tax credit or production tax credit. Those tax credits are recorded as part of operating cash flows. In contrast, the grant is a one-time payment received to reimburse the reporting entity for the cost of construction. Therefore, although the grants are an alternative to the income tax benefits, due to the nature of the grant, we believe such amounts should generally be classified as an investing activity.

Deferred income

We believe reporting entities may recognize deferred income as a part of operating expenses or as part of other income in the income statement. Because both presentations relate to operations, we would expect that the grant cash inflows would be presented as an operating cash flow in the statement of cash flows.

21.16.3.2 *Income grants*

Grants related to income reimburse operating expenses of the reporting entity. Therefore, any timing differences between recognition and receipt of these grants should be recognized in the operating section of the statement of cash flows.

21.16.4 *Disclosure*

Disclosures related to the receipt of government grants should include:

- The accounting policy for government grants, including how they are presented in the financial statements
- The nature and extent of government grants recognized in the financial statements
- Whether there are unfulfilled conditions and other contingencies that attach to government grants that have been recognized

In addition, the reporting entity should disclose if there are other forms of government assistance from which it has directly benefited.

Ongoing standard setting

At the time of release of this guide, the FASB had an active project on its agenda regarding disclosure of certain government grants. Preparers and other users of this publication should monitor the status of the project, and if finalized, evaluate its effective date and implications.

21.17 *Regulated operations*

Regulated utilities are subject to the overall presentation and disclosure requirements applicable to reporting entities in general. However, due to the nature of their operations, regulated utilities also have additional presentation and disclosure considerations.

See UP 21.18 and 21.19 for further information on specific disclosure considerations related to regulated utility plant and regulated income taxes and UP 21.20 for specific considerations related to the presentation and disclosure of business combinations involving regulated utilities.

21.17.1 Presentation

Because of the regulatory process and resulting economic effects, the presentation of the financial statements of a regulated utility may differ from entities in general. Common differences and other considerations for the financial statements of regulated utilities are highlighted in Figure 21-6.

Figure 21-6**Common considerations in financial statement presentation for regulated utilities**

Financial statement	Common presentation considerations
Balance sheet	<ul style="list-style-type: none"> □ Utility plant may be presented as the first caption on the asset side of the balance sheet due to plant's economic significance to the business. □ Capitalization (inclusive of long-term debt) may be presented before liabilities, because funds invested in utility plant are primarily obtained from these sources.
Income statement	<ul style="list-style-type: none"> □ Common captions include operating revenue, operating expenses, other income and expense, and interest charges. □ Operating expenses determined as part of a regulated utility's revenue requirement are included "above-the-line" (i.e., within operating income). □ Results from nonutility operations, such as finance charges, are generally classified "below-the-line." □ ASC 225, <i>Income Statement</i>, requires that if a regulated utility uses a uniform system of accounts or files a prescribed form (e.g., FERC Form 1), the general segregation of operating revenues and operating expenses should be classified in the income statement consistent with the form (ASC 225-10-S99-2). □ Regulated utilities that are consolidated with unregulated entities (e.g., a public utility holding company) generally present the income statement consistent with entities in general.
Statement of cash flows	<ul style="list-style-type: none"> □ The presentation of cash flows is consistent with entities in general. □ Items that are included in the regulated utility's operating income are generally classified in operating cash flows (see UP 18.3 for further information on the classification of AFUDC). Within operating cash flows, movements within regulatory accounts are typically included within a line item for changes in regulatory assets and liabilities or within amortization or non-cash adjustments to net income.

In addition to the items highlighted in the figure, regulated utilities should consider the presentation matters related to specific accounts described in the following sections.

21.17.1.1 Regulatory assets and liabilities

The presentation of regulatory assets and liabilities on the balance sheet is primarily dependent on the regulatory jurisdiction for which rates are being collected or refunded, as well as the method and timing of recovery. ASC 210-20-45-1 provides relevant guidance in assessing whether regulatory assets and liabilities within a specific jurisdiction may be offset.

ASC 210-20-45-1

A right of setoff exists when all of the following conditions are met:

- a. Each of two parties owes the other determinable amounts.
- b. The reporting party has the right to set off the amount owed with the amount owed by the other party.
- c. The reporting party intends to set off.
- d. The right of setoff is enforceable at law.

If these conditions do not exist, regulatory assets and liabilities should be reported on a gross basis. Although the regulator may consider regulatory assets and liabilities together as part of the regulatory process, in general, such amounts are not offset. Therefore, we would expect netting of regulatory assets and liabilities on the balance sheet to be limited.

Furthermore, regulatory assets and liabilities should never be reported “net of tax.” Deferred income taxes and regulatory assets and liabilities that are recorded in respect of those deferred income taxes should be presented on a gross basis. See UP 19.7 for further discussion of “net of tax” reporting.

ASC 980 does not specifically discuss the classification of regulatory assets or liabilities as current versus noncurrent. However, if a regulated utility presents a classified balance sheet (i.e., separate classification of current assets and current liabilities), it should consider the classification of regulatory accounts as current versus noncurrent. While many regulatory assets and liabilities are recovered or passed back over a longer period, entities may have some assets or liabilities that are recovered or refunded within an operating cycle. For example, some jurisdictions have established fuel or purchased power cost recovery mechanism whereby any over or under collections are included in rates in the subsequent month or quarter. In these instances, it is appropriate to classify the regulatory asset or liability as current. If a regulatory asset or liability will only be partially recovered or refunded in the next year, a reporting entity may consider the entire regulatory asset or liability to be the unit of accounting and classify it as non-current.

21.17.1.2 Presentation of capital

Regulated utilities often follow a “total capitalization” aggregation on the balance sheet. The SEC staff has permitted this presentation; however, in certain filing reviews, the SEC staff has expressed a view that regulated utilities should provide separate subtotals for any mandatorily redeemable preferred stock and debt. Further, the SEC staff has indicated that an additional subtotal that aggregates common stock and mandatorily redeemable securities is not permitted.

21.17.2 Discontinuation of regulated accounting for a separable portion of the business

When recording the results of a total or partial discontinuation of ASC 980, no restatement of prior period information is permitted. The SEC staff has required registrants to report the write-off in the current quarter in which a final agreement or rate order occurs. This is consistent with ASC 980-20-40-6, which requires that the discontinuation of ASC 980 be applied when deregulatory legislation is passed or when a rate order that contains sufficient information to reasonably determine the impact of deregulation has been issued.

In addition, once a regulated utility discontinues the application of ASC 980 to a portion of the business, it should consider the presentation of the unregulated activities. ASC 980-20-45-1 requires that the activities related to the separable portion of the business that no longer applies ASC 980 be separately presented in the financial statements either on the face of the financial statements or in the footnotes.

21.17.2.1 Reapplication of ASC 980

A regulated utility that reapplies ASC 980 to all or a portion of its operations should report the net adjustment resulting from the reapplication in the income statement within results of operations.

21.17.2.2 Classification and measurement of subsidiary preferred shares

Public utility holding companies sometimes have subsidiaries that have issued preferred shares. In such cases, the parent company and the subsidiary will need to consider whether there are specific classification requirements related to those preferred shares (i.e., as debt or equity) pursuant to ASC 480-10-S99. It is common in the industry for preferred shares issued by a public utility holding company’s subsidiaries to have the following provisions:

- The shares are callable by the subsidiary
- The shares allow the holders to gain control of the subsidiary’s board if it does not pay dividends for a certain number of consecutive periods

These provisions, if exercised, provide the preferred security holders with the ability to effectively put the shares by forcing the subsidiary to exercise the call option if the subsidiary does not pay dividends in accordance with the share agreement. Although the holding company and subsidiaries should consider all facts and circumstances,

generally such shares are considered redeemable outside the control of the subsidiary and should be classified as temporary equity. See FG 4 for information on how such shares should be classified by the subsidiary and the parent company.

21.17.3 **Disclosure**

Regulated utilities are subject to the same disclosure requirements as entities in general and also have supplemental requirements that arise as a result of applying ASC 980. Figure 21-7 summarizes the regulatory-specific disclosure requirements as stipulated in ASC 980.

Figure 21-7
Summary of disclosures required by ASC 980

Area	Required disclosures
Regulatory assets	<ul style="list-style-type: none"> □ Any regulatory assets and the remaining recovery period when recovery of costs is provided without a return during the recovery period (ASC 980-340-50-1) □ The terms of any phase-in plans that are in effect ordered for future periods, including disclosure of amounts deferred for ratemaking purposes and changes in those amounts (ASC 980-340-50-2) □ The nature and amounts of any allowance for earnings on shareholders' investment capitalized for ratemaking purposes but not capitalized for financial reporting (ASC 980-340-50-3) □ A description of the regulatory treatment of OPEB costs, the status of any pending regulatory action, the amount of any such costs deferred as a regulatory asset, and the period over which the deferred amounts are expected to be recovered in rates (ASC 980-715-50-1)
Revenue subject to refund (ASC 980-605-50-1)	<ul style="list-style-type: none"> □ For refunds that are recognized in a period other than the period in which the related revenue was recognized and that have a material effect on net income, disclose the effect on net income and indicate the years in which the related revenue was recognized. □ Revenue subject to refund may be disclosed, net of tax, as a line item in the income statement; however, it should not be presented as an extraordinary item.
Discontinuation (ASC 980-20-50-1 and 50-2)	<ul style="list-style-type: none"> □ The reasons for the discontinuation □ The portion of operations to which application of rate-regulated accounting is being discontinued □ Disclosure requirements for unusual or infrequently occurring items (as defined in ASC 225) may apply to the net adjustment reported in the income statement as a result of discontinuing regulatory accounting

Area	Required disclosures
Reapplication	<p>ASC 980 does not include specific disclosure requirements related to reapplication of regulatory accounting. Depending on the significance of reapplication to the financial statements, regulated utilities should consider disclosing:</p> <ul style="list-style-type: none"> □ The reasons for the reapplication □ The portion of operations to which regulatory accounting is being reapplied □ The net adjustment reported in the income statement as a result of reapplying regulatory accounting □ Details of regulatory assets and liabilities recorded as a result of the reapplication

The impact of regulation on a regulated utility cannot be overemphasized. Therefore, the regulated utility should consider prominent disclosure of the effects of regulation.

21.17.4 Environmental obligations

Regulated utilities often have significant environmental clean-up costs. These types of costs may be incurred over a long period. The determination of whether to accrue a liability for these costs depends on the facts and circumstances and the guidance in ASC 410-30 and ASC 450-20 should be followed.

SAB Topic 10.F, *Presentation of Liabilities for Environmental Costs* (codified in ASC 980-410-S99-1), also provides specific guidance related to the potential impact of regulatory recovery on the accounting for environmental remediation liabilities:

- A regulated utility may not present estimated liabilities for environmental costs net of probable future revenue resulting from the inclusion of such costs in allowable costs for ratemaking.
- A regulated utility may not delay recognition of a probable and estimable liability for environmental costs while a regulator debates potential recovery of the costs.

The SEC guidance indicates that an environmental remediation liability may be an allowable cost that qualifies for recognition as a regulatory asset. However, consistent with the overall model for application of the impact of regulation, a reporting entity should evaluate, measure, and record environmental remediation liabilities in accordance with the U.S. GAAP guidance for entities in general. Any potential regulatory recovery should be evaluated and recognized in accordance with the criteria in ASC 980-340-25-1.

21.17.5 Disclosure considerations when return is capitalized only for ratemaking

ASC 980-340-50-3 requires disclosure of any allowance on shareholder investment capitalized for ratemaking purposes but not recognized for financial reporting.

21.17.6 Other suggested regulated operations disclosures

In addition to the disclosure requirements of ASC 980 for regulated operations, disclosures about the effects of regulation continue to be an area of SEC attention. Regulatory environments differ significantly among states, regions, and entities. As such, reporting entities may want to consider whether their regulatory disclosures provide readers with a comprehensive understanding of their current regulatory environment and the related impact on their businesses. Regulated utilities should consider providing the following disclosures about rate-regulated activities in SEC filings:

- Whether the financial statements have been prepared in accordance with ASC 980 and the basis for the continued application of regulatory accounting, particularly when it has been an unusually long period since the last rate case
- The nature, amount, and basis of regulatory assets deferred, and the recovery period when the amount is classified on the balance sheet, and whether a return is being earned
- The impact of regulation on the business (e.g., for recent rate orders received, an explanation of the impact the new rate orders had on the period reported, and the impact new rates are expected to have on the business in the future)
- The existence of and associated impact of stabilization mechanisms or disallowances
- The nature of significant deferrals created by the regulatory process (e.g., plant abandonment or other stranded costs, deferred fuel costs, environmental remediation costs)
- Pending rate cases and their potential future effects on operations

Reporting entities may also want to consider disclosing the extent to which changes are taking place that may lead to a future conclusion that all or a portion of the business may not qualify in the future for continued application of regulatory accounting.

21.18 Regulated operations – utility plant

21.18.1 Financial statement classification and disclosure of allowance for funds used during construction

Balance sheet

ASC 980-360-25-1 specifies that AFUDC should be capitalized “as part of the acquisition cost of the related asset.” Consistent with this guidance, AFUDC should be recorded as part of utility plant, not as a separate regulatory asset.

Income statement

ASC 980-835-45-1 provides guidance for the income statement classification of AFUDC, indicating that it may be an item of other income, a reduction of interest expense, or both (i.e., the debt component reported as a reduction of interest expense and the equity component included in other income).

Statement of cash flows

ASC 230 does not address the classification of AFUDC. However, it does specify that capitalized interest on property, plant, and equipment is a cash outflow from investing activities:

Excerpt from ASC 230-10-45-13

All of the following are cash outflows for investing activities: ... (c) Payments at the time of purchase or soon before or after purchase to acquire property, plant, and equipment and other productive assets, including interest capitalized as part of the cost of those assets.

Consistent with this guidance, the debt portion of AFUDC should be classified within investing activities in the statement of cash flows.

Similar to the debt component, the equity portion of AFUDC is a noncash increase to net income in the income statement. However, the capitalization of the cost of equity arises due to regulated accounting and is not covered by the guidance for capitalized interest. Therefore, the equity portion of AFUDC should be reported as a noncash adjustment to net income (i.e., a reduction of operating cash flows).

Disclosure

ASC 980-340-50-3 requires disclosure of any allowance on shareholder investment capitalized for ratemaking purposes but not recognized for financial reporting.

21.18.2 *Presentation of lease expense*

As a practical matter, the recording of rental expense under the applicable depreciation and interest expense captions of the income statement is not required.

Excerpt from ASC 980-840-55-1

Paragraph 840-30-45-3 states that an entity is not required to classify interest expense or amortization of leased assets as separate items in an income statement. ... For example, the amounts of amortization of capitalized leased nuclear fuel and interest on the related lease obligation could be combined with other costs and displayed as fuel cost. However, in that circumstance, the disclosure of total interest cost incurred, required by Subtopic 835-20, would include the interest on that lease obligation; and the disclosure of the total amortization charge, required by paragraph 840-30-45-3, would include amortization of that leased asset.

Regulated utilities typically include lease expense as a component of operating expenses and do not separately classify the related amortization and interest expense. However, ASC 980-840-55-1 indicates that regulated utilities should disclose these amounts.

21.18.3 Accelerated cost recovery of plant

The SEC staff has questioned regulated utilities that have embedded regulatory liabilities within accumulated depreciation and has required reclassification of those amounts as separate liabilities. In addition, the SEC staff has commented that the resulting regulatory liability should be disclosed. If the amount of the regulatory liability is not known, the regulated utility should provide additional disclosure, including:

- The consequence of the ratemaking process to the recognition of depreciation expense
- The extent to which regulatory recovery periods differ from the useful lives that would have been used absent regulatory accounting
- A statement that quantification of the cumulative effect of the difference cannot be determined

21.18.4 Income statement classification of loss on abandonment

Regulated utilities should present any loss on abandonment of utility plant as part of income from continuing operations.

21.18.5 Income statement classification of loss on disallowances

The income statement classification of disallowances is the same as that for abandonments.

21.18.6 Utility plant adjustments

The SEC disclosure rules dictating the form and content of financial statements provide certain requirements related to utility plant adjustments, described in the following excerpt:

S-X 5-02(13)(b)

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

For example, the FERC system of accounts requires that when there is an acquisition of a utility company or utility assets, the difference between the purchase price and

the original cost of a fixed asset to the first entity devoting that asset to utility service be recorded in a separate account as a plant acquisition adjustment. In this example, the SEC rule would require disclosure of the original cost of the plant and the acquisition adjustment, as required by the FERC system of accounts. We believe such disclosure requirements, if applicable, can be met by reflecting these categories on the face of the balance sheet or through footnote disclosure.

21.18.7 *Financing through construction intermediaries*

SAB Topic 10.A, *Financing by Electric Utility Companies through use of Construction Intermediaries*, which was codified in ASC 980-810-S99-2, provides guidance on the presentation of construction work in progress and capitalized interest when a regulated utility uses a third party to finance construction of a generating plant.

The typical case described by the guidance involves establishing a trust or corporation (construction intermediary) to which the utility assigns its interest in property or other contractual rights. The construction intermediary finances the construction, guaranteed by the construction work in progress as well as by the obligation of the utility to purchase the plant at the completion of construction. In some cases, the utility also may commit to make up deficiencies in the funding provided by the construction intermediary. During construction, interest will be capitalized. The question that arises in these structures is whether the construction work in progress, related liabilities, and interest expense being generated by the construction intermediary should be presented on the utility's financial statements.

SAB Topic 10.A requires these amounts to be reported in the utility's financial statements in the applicable captions (effectively concluding that the construction intermediary should be consolidated by the utility). We generally expect a consolidation conclusion to be consistent with the application of ASC 810. However, reporting entities applying this guidance should also evaluate the impact of ASC 810 when evaluating the appropriate accounting.

21.18.8 *Cost of removal recovered through rates*

Any regulatory liability recognized for the cost of removal collected in rates should be classified as a liability on the balance sheet and not as an offset to utility plant.

Amounts expended for the removal of assets where no legal obligation exists are generally reflected as investing cash outflows in the statement of cash flows as they are related to the disposal of property, plant, and equipment.

21.19 *Regulated operations – income taxes*

ASC 980-740-25-1(a) prohibits net-of-tax accounting and reporting. For example, the regulated utility should determine the rate used to capitalize the debt portion of AFUDC on a gross basis, with deferred income taxes separately calculated. Regulated utilities should not include deferred income taxes related to the debt portion of AFUDC in the utility plant balances; they should present such amounts on a gross basis.

In addition, in accordance with ASC 980-740-55-1, regulatory assets and liabilities are not offset with the related deferred tax liabilities or assets. The regulated utility should record each separately because the balances pertain to different counterparties. Tax-related regulatory assets and liabilities should be segregated into current and noncurrent balances using the ASC 740 criteria for classification of deferred income tax balances.

Ongoing standard setting

In November 2015, the FASB issued ASU 2015-17, which requires deferred taxes to be classified as noncurrent assets and liabilities by jurisdiction. Reporting entities should refer to this ASU to determine the effective date of the new guidance.

21.19.1 Disclosure

From a disclosure standpoint, if tax-related regulatory assets or liabilities are material to the financial statements, disclosures similar to those provided for deferred income taxes should be provided. This would include information related to the likely reversal pattern for the regulatory assets and liabilities and necessary regulatory actions that are expected to occur in the future.

Regulated utilities should also consider separately presenting or disclosing the amount of income tax expense recovered in rates as part of operating income (“above the line”) and income tax expense related to the unregulated operations as part of the traditional income tax expense line item (“below the line”). For example, if a regulated utility records miscellaneous revenues or gains on the sale of property when such revenues or gains are not considered in the ratemaking process, the related income taxes would be reported “below-the-line.” Although this reporting is not a requirement under U.S. GAAP, separate presentation and/or disclosure of these portions of the income tax provision can provide useful information to financial statement users.

21.20 Regulated operations – business combinations

As discussed in UP 20, a business combination that involves a regulated utility may have certain unique issues as a result of the impact of regulation. Recent SEC staff comments have focused on these unique issues, including:

- The considerations related to recording property, plant, and equipment at fair value or book value
- The considerations related to recording an offsetting regulatory balance for the fair value adjustment to debt
- The considerations related to recognizing separately from goodwill identifiable intangible assets acquired, such as power purchase contracts

- The location where the acquirer recorded the purchase price allocation for the acquiree's regulatory assets and liabilities
- The reasons for significant adjustments to the initial purchase price allocation, such as the intervening events that occurred and/or information that was received from the initial closing of the transaction to the finalization of the purchase price and the reasons that such information was not available at an earlier date

The SEC staff has requested further clarification related to conclusions reached and additional disclosure.

Acquisition-date fair value amounts recorded for power purchase agreements are not required to be included in subsequent ASC 815 and ASC 820 disclosures.

21.21 Management discussion and analysis

21.21.1 Derivative disclosures

In addition to ASC 815's disclosure requirements, SEC registrants are required to follow the SEC's market risk disclosure rules. Accordingly, SEC registrants should include certain derivative disclosures both in the footnotes as required by ASC 815 and outside the financial statements as required by the SEC's rules.

21.21.2 Use of non-GAAP measures

Many utilities and power companies who are SEC registrants report non-GAAP financial measures as part of their Management's Discussion and Analysis of Financial Condition and Results of Operations in their Form 10-Ks and Form 10-Qs. A non-GAAP financial measure is a numerical measure of a registrant's historical or future financial performance, financial position or cash flows that:

- excludes amounts, or is subject to adjustments that have the effect of excluding amounts, that are included in the most directly comparable measure calculated and presented in accordance with GAAP in the statement of income, balance sheet or statement of cash flows (or equivalent statements) of the registrant (e.g., income excluding restructuring charges); or
- includes amounts, or is subject to adjustments that have the effect of including amounts, that are excluded from the most directly comparable GAAP measure so calculated and presented (e.g., a revenue measure that combines revenues earned by equity method investees with consolidated revenues).

Commonly used non-GAAP financial measures for utilities and power registrants include gross margin (e.g., electric or gas sales minus purchased power and/or fuel costs), earnings before interest and taxes (EBIT) and earnings before interest, taxes, depreciation and amortization (EBITDA) or adjusted earnings or adjusted earnings per share, among others.

Non-GAAP financial measures included in information that is "filed" with the SEC are subject to the requirements of Regulation G (see SEC 6020.21) and the requirements

contained in Instruction 2 to Form 8-K 2.02 (see SEC 6020.22), which require the following:

- the registrant to disclose the most directly comparable financial measure calculated and presented in accordance with GAAP **with equal or greater prominence** (as compared to the non-GAAP financial measure);
- a statement disclosing the reasons why management believes that the non-GAAP financial measure provides useful information to investors;
- a statement disclosing the additional purposes, **if any**, for which management uses the non-GAAP financial measure (to the extent material); and
- a reconciliation (by schedule or other clearly understandable method) between the non-GAAP financial measure disclosed or released and the most comparable financial measure or measures calculated and presented in accordance with GAAP.

Additionally, non-GAAP financial measures included in information that is “filed” with the SEC are subject to a number of prohibitions, as follows:

- Excluding charges or liabilities that require cash settlement from non-GAAP liquidity measures (other than the measures of EBIT or EBITDA);
- Adjusting a non-GAAP performance measure to eliminate or smooth items **identified as** nonrecurring, infrequent or unusual, when (i) the nature of the charge or gain is such that it is reasonably likely to recur within two years or (ii) there was a similar charge or gain within the prior two years;
- Presenting non-GAAP financial measures on the face of the financial statements prepared in accordance with GAAP or in the accompanying notes;
- Presenting non-GAAP financial measures on the face of any pro forma financial information required to be disclosed by Article 11 of Regulation S-X; and
- Using titles or descriptions of non-GAAP financial measures that are the same, or confusingly similar to, titles or descriptions used for GAAP financial measures (e.g., referring to EBITDA as “operating earnings”).

The SEC staff cautioned that it had seen certain non-GAAP measures that are misleading and therefore not permitted. At the 2012 AICPA Conference on Current SEC and PCAOB Developments and in recent public speeches, the SEC Staff has provided examples of non-GAAP items it has objected to, including full non-GAAP income statements and non-GAAP measures that exclude expenses considered to be integral to operating the business. One commonly cited example is a non-GAAP measure that excludes normal cash expenses necessary to operate the business (such as advertising costs or salaries). Utilities and power registrants should continue to exercise caution when evaluating whether to disclose non-GAAP measures, which measures to disclose, and how to present those measures.

Non-GAAP measures may also be included in information “furnished” to the SEC (e.g., company press release) or publicly disclosed in another way (e.g., orally, telephonically, by a webcast). Certain of the disclosure requirements above apply also to this information. See SEC 6020 for further discussion.

21.21.3 *Climate change disclosures*

Climate change disclosures have recently become another focal point of the SEC staff. In February 2010, the SEC issued interpretive guidance to assist companies in applying existing SEC disclosure requirements when discussing the implications of climate change. This interpretive release is available on the SEC’s internet website at <http://www.sec.gov/rules/interp/2010/33-9106fr.pdf>. The guidance highlights the following areas as examples of where climate change may trigger disclosure requirements:

- Impact of legislation and regulation.
- Impact of international accords.
- Indirect consequences of regulation or business trends.
- Physical impacts of climate change.

21.21.3.1 *Earnings to fixed charges*

The Securities Act registration forms require the inclusion in tabular form of the ratio of earnings to fixed charges in the prospectus if debt securities are being registered. A tabular presentation of the ratio of earnings to combined fixed charges and preferred stock dividends is required in the prospectus if preferred stock is being registered. A tabular presentation of both ratios is required in the prospectus when the issuer prepares a shelf registration statement relating to debt securities and preferred stock to be sold on a delayed or continuous basis in the future. Disclosure of both of the ratios is permitted in any registration statement relating to debt or preferred stock and either ratio or both ratios may be disclosed voluntarily in other filings, including those on Exchange Act forms. Additionally, SEC guidance requires that a schedule setting forth, in reasonable detail, the manner of the ratio calculation be included as Exhibit 12 to the filing. The exhibit is required regardless of whether the ratio of earnings to fixed charges is included in a filing by requirement or on a voluntary basis. The ratios should be presented in the prospectus for each of the last five fiscal years and the latest interim period for which financial statements are required. The components of the ratio are defined in Figure 21-8 below.

Figure 21-8
Ratio of earnings to fixed charges

Component	Definition
Fixed charges	<p>The term “fixed charges” means the total of:</p> <ul style="list-style-type: none"> □ Interest costs, both expensed and capitalized, excluding losses recognized on early extinguishment of debt. Although not specifically addressed in SEC guidance, we believe that interest costs that are deferred as a regulatory asset should be included as part of interest costs when calculating the total of fixed charges. □ Amortization of debt expense and discount or premium relating to any indebtedness, whether expensed or capitalized. □ Such portion of rental expense as can be demonstrated to be representative of the interest factor. In calculating the interest factor, the SEC will continue to accept one-third of rental expense relating to operating leases as the interest portion thereof, provided management believes and can support it represents a reasonable approximation of the interest factor. □ The amount of pre-tax earnings required to cover any preferred stock dividend requirements <u>of consolidated subsidiaries</u> and any accretion in carrying value of redeemable preferred stock <u>of consolidated subsidiaries</u>, excluding in all cases, items which would be or are eliminated in consolidation. □ If a registrant has been required to satisfy its guarantee of the debt of a less than 50%-owned person or of an unaffiliated person (such as a supplier), or it is probable that the registrant will be required to honor the guarantee and the amount can be reasonably estimated, interest and amortization of premium or discount (if any) associated with such debt should be included in fixed charges.

Component	Definition
Earnings	<p>The term “earnings” is the amount resulting from adding and subtracting the following items.</p> <p>Add:</p> <ul style="list-style-type: none"> □ pre-tax income from continuing operations before adjustment for noncontrolling interest and income or loss from equity investees; □ Fixed charges □ Amortization of interest costs deferred as a regulatory asset □ Amortization of capitalized interest (see note below) □ Distributed income of equity investees □ The registrant’s share of pre-tax losses of equity investees for which charges arising from guarantees are included in fixed charges. <p>Subtract:</p> <ul style="list-style-type: none"> □ Interest capitalized (see note below related to AFUDC) □ Interest deferred as a regulatory asset □ Preference security dividend requirements of consolidated subsidiaries □ The noncontrolling interest in pre-tax income of subsidiaries that have not incurred fixed charges. <p>Note: Public utilities following ASC 980 should not add amortization of capitalized interest in determining earnings, nor reduce fixed charges by any allowance for funds used during construction.</p>

Required disclosures with respect to the earnings ratio are as follows:

- If the ratio computation indicates a less than one-to-one coverage, state that earnings are insufficient to cover fixed charges or combined fixed charges and preferred dividends and disclose the dollar amount of the coverage deficiency. The deficiency to be disclosed is the dollar amount of earnings required to attain a ratio of one-to-one. We recommend that ratios of less than one-to-one not be presented.
- The ratios are normally disclosed in tabular format within the body of the prospectus, either in selected financial data or in a separate table. The method of computation should be briefly set forth in a footnote to the ratio presentation. If the issuer provides a summary or similar section in the prospectus, the ratio(s) should be shown in that section.

- An exhibit setting forth in reasonable detail the computation of any earnings ratios which appear in a registration statement or report. SEC 2500.4 and SEC 2500.5 illustrate an acceptable level of detail.
- The issuer's policy with respect to (a) the determination of the interest portion of rental expense included in fixed charges; (b) the treatment of interest on uncertain tax positions; (c) the nature of guarantee arrangements and how the issuer has treated the guarantee in the calculation; and (d) the policy applied to accretion of redeemable preferred stock that is not classified as a liability.

See SEC 2500 for further discussion of the ratio of earnings to fixed charges.

21.21.4 Schedules commonly required for utilities and power registrants

Utilities and power companies subject to S-X Article 5 are required by S-X 5-04 to file certain supplementary financial statement schedules unless the schedules are either inapplicable or specifically excepted by the form being filed. The schedules required by S-X Article 5 are not required for interim periods. It also should be noted that S-X 5-04(b) permits the information required by any schedule to be shown in the related financial statements or notes thereto and the schedule omitted, if this can be done without making the statements unclear or confusing. The condensed financial information of a registrant (Schedule I) and valuation and qualifying accounts (Schedule II) are two of the most common financial statement schedules applicable to utilities and power registrants.

21.21.4.1 Schedule I

Schedule I is required if at the end of the most recently completed fiscal year, the registrant's proportionate share of restricted net assets (as defined in S-X 4-08(e) after intercompany eliminations and after applying "push-down" accounting) of consolidated subsidiaries exceeds 25% of total consolidated net assets. In this context, "consolidated net assets" is considered by the SEC staff to be the registrant shareholders' equity (i.e., not total equity). If this condition is met, condensed parent company financial data is required as of the same balance sheet dates and for the same income and cash flow statement periods for which audited consolidated financial statements are required. Complete footnotes to the condensed parent company statements are not required, except for:

- Descriptions of material contingencies, significant provisions of long-term obligations, mandatory dividend or redemption requirements of redeemable stocks, and guarantees of the parent company, unless such disclosures have been separately discussed in the consolidated financial statements.
- A five-year schedule of the maturities of the parent's obligations.
- Disclosure of cash dividends paid to the parent by consolidated subsidiaries, unconsolidated subsidiaries and 50% or less-owned persons, respectively, for each of the last three fiscal years.

Footnotes to the schedule generally refer to the footnotes of the consolidated financial statements for descriptions of material contingencies and significant provisions of long-term obligations and guarantees of the parent, including a five-year schedule of maturities, etc.; however, additional footnotes to the schedule may be required to supplement the disclosures of the consolidated financial statements. For example, a typical disclosure informs the reader of the basis of accounting for the parent company's majority-owned subsidiaries. See SEC 4510 for further discussion of the Schedule I requirement and the restricted net assets test.

21.21.4.2 *Schedule II*

This schedule is filed in support of reserves included in the balance sheet. Immateriality is the only criterion for omission. Because of the nature of reserves, the SEC considers their significance to be independent of the amount involved and therefore the normal standards of materiality would not necessarily apply. It should be noted that this schedule was designed to present an analysis of valuation reserves only (such as the allowance for doubtful accounts) and was not intended for accruals and estimated liabilities; however, the SEC often requests that various accruals or miscellaneous liabilities (e.g., restructuring reserves) also be included on the schedule, even if such amounts are not classified as reserves on the balance sheet. Activity with respect to any valuation allowance on deferred tax assets should be presented in this schedule.

21.22 *Other comprehensive income*

ASC 220, *Comprehensive Income*, provides the definition of comprehensive income and other comprehensive income (OCI).

Definitions from ASC 220-10-20

Comprehensive Income: The change in equity (net assets) of a business entity during a period from transactions and other events and circumstances from nonowner sources. It includes all changes in equity during a period except those resulting from investments by owners and distributions to owners. Comprehensive income comprises both of the following: a) All components of net income b) All components of other comprehensive income.

Other Comprehensive Income: Revenues, expenses, gains, and losses that under generally accepted accounting principles (GAAP) are included in comprehensive income but excluded from net income.

Common amounts recorded as other comprehensive income for utilities and power companies include gains and losses on derivative instruments, unrealized gains and losses on certain investments in debt and equity securities, and pension and other postretirement benefit items.

ASC 220 is applicable to all reporting entities, except for those that have no items of OCI in any period presented, or for not-for-profit organizations that follow ASC 958-

205. FSP 4 summarizes the comprehensive income disclosure requirements as stipulated in ASC 220.

21.23 *Disclosure of noncash investing and financing activities*

ASC 230 requires separate disclosure of all investing or financing activities that do not result in cash flows in a narrative or tabular format. The noncash activities may be included on the same page as the statement of cash flows, in a separate note, or in other notes as appropriate. If there are only a few transactions, it may be convenient to include them on the same page as the statement of cash flows. We believe that specific facts and circumstances dictate the appropriate treatment. Common examples of noncash investing and financing transactions for utilities and power companies are:

- Acquiring assets by assuming directly related liabilities (e.g., amount of capital expenditures included in accounts payable as of a period-end)
- Obtaining an asset by entering into a capital lease
- Declaration of a dividend (if not paid)
- Issuing stock in connection with a stock compensation plan where no cash payment is required
- Recording the investor's share of the equity earnings of the investee

21.24 *Loss contingencies and commitments*

21.24.1 *Loss contingency disclosures*

ASC 450, *Contingencies*, specifies the accounting and disclosure requirements for contingencies. Contingencies are defined as an existing condition, situation, or set of circumstances involving uncertainty as to possible gain or loss to an entity that will ultimately be resolved when one or more future events occur or fail to occur. Examples of contingencies for utilities and power companies include environmental liabilities, legal disputes, and incurred but not reported personal injury claims, among others.

Disclosure is required of certain loss contingencies that do not meet the conditions for accrual (i.e., are probable and reasonably estimable). Disclosure is required of material loss contingencies that are probable but not reasonably estimable, and of those that are at least reasonably possible (but not probable) regardless of whether they are reasonably estimable. The estimability requirement is intended to prevent accrual of amounts that are so uncertain that they would impair the integrity of the financial statements; however, as discussed at ARM 5360.3, reasonable estimates should be made for certain types of losses that result from customary and continuing business activities. For contingencies that meet the criteria for disclosure, ASC 450-20-50-4 requires an entity to disclose the nature of the contingency and an estimate of the possible loss or range of loss (or a statement that such an estimate cannot be made).

The SEC staff continues to focus on loss contingency disclosures. The SEC staff has emphasized the following:

- For loss contingencies that are reasonably possible (but not probable), disclosures required by ASC 450 regarding the nature of the contingency and the possible range of amounts
- It would be unusual if a company could not reasonably estimate a range of loss for at least some of its contingencies
- More robust disclosures are expected as cases progress
- Reporting entities should be able to adequately support their conclusion that an estimate of a reasonably possible loss cannot be made, particularly when loss contingency matters have been ongoing for an extended period of time
- The guidance does not permit companies to avoid providing an estimate solely because an estimate cannot be made “with precision” or “with confidence”
- The recording of a material accrual for a contingent liability related to a historical event should generally not be the first disclosure regarding the contingency

For further discussion of accounting for contingencies, see ARM 5360.

21.25 *Unconditional purchase obligations*

ASC 440, *Commitments*, specifies the disclosure requirements of long-term unconditional purchase obligations, such as take-or-pay contracts, through-put contracts, and leases. Unconditional purchase obligations that meet characteristics specified in ASC 440-10-50-2 need to be disclosed.

ASC 440-10-50-2

- a. It is noncancelable, or cancelable only in any of the following circumstances:
 1. Upon the occurrence of some remote contingency
 2. With permission of the other party
 3. If a replacement agreement is signed between the same parties
 4. Upon payment of a penalty in an amount such that continuation of the agreement appears reasonably assured.
- b. It negotiated as part of arranging financing for the facilities that will provide the contracted goods or services or for costs related to those goods or services (for example, carrying costs for contracted goods). A purchaser is not required to investigate whether a supplier used an unconditional purchase obligation to help secure financing, if the purchaser would otherwise be unaware of that fact.
- c. It has a remaining term in excess of one year

For unconditional purchase obligations that meet the criteria above and have not been recognized on an entity's balance sheet, disclosure requirements include (a) the nature and term of the obligations, (b) the amount of the fixed and determinable portion of the obligations as of the date of the latest balance sheet presented in the aggregate and, if determinable, for each of the five succeeding fiscal years, (c) the nature of any variable components of the obligations, and (d) the amounts purchased under the obligations for each period for which an income statement is presented. ASC 440-10-50 allows disclosures of similar or related unconditional purchase obligations to be combined.

For unconditional purchase obligations that are recorded in the financial statements, disclosure of the aggregate amount of payments for unconditional purchase obligations for each of the five years following the date of the latest balance sheet presented is required by ASC 440-10-50-6.

Future minimum lease payments under leases that meet the conditions of ASC 440-10-50-2 do not need to be disclosed if those future minimum lease payments are disclosed in accordance with ASC 840.

In addition to disclosure considerations, companies should evaluate their unconditional purchase obligations to determine if those obligations meet the definition of a derivative in their entirety (e.g., a long-term contract to purchase electricity) or have an embedded derivative that needs to be bifurcated and accounted for separately under the provisions of the guidance on derivatives (ASC 815) (e.g., a long-term purchase contract with a price adjustment mechanism that is not clearly and closely related). See UP 3.

If an unconditional purchase obligation is subject to the requirements of ASC 440 and ASC 815, the reporting entity should comply with the disclosure requirements of both standards.

Utilities and power companies also should consider whether unconditional purchase obligations are in substance leases of the underlying plant. See UP 2.

21.26 *Disclosures for subsidiaries participating in parent company pension plans*

Many utilities and power companies have subsidiaries with stand-alone reporting requirements that participate in a pension plan sponsored by an affiliate entity (e.g., parent company). When an entity participates in a pension plan sponsored by an affiliated entity, the accounting in stand-alone financial statements of that entity should generally follow the "multiemployer" guidance in ASC 715, *Compensation—Retirement Benefits*.

The multiemployer guidance differs significantly from the traditional "single employer" accounting guidance in ASC 715. Under multiemployer accounting, a subsidiary would typically record expense based on its required contribution to the plan for the period, with recognition of a liability only for contributions that remain unpaid as of period end. (Note: In affiliated entity situations, other expense allocation

approaches may also be appropriate, such as an allocation of parent expense based on headcount, total salaries, etc.) See UP Question 17-11 for consideration of whether a parent company can record an offsetting regulatory asset if the ASC 715 liability is not recorded in a regulated subsidiary's separate financial statements.

A subsidiary participating in its parent's single employer plan should disclose the amount of contributions to the plan and the name of the plan. Unless a subsidiary is a sponsor of its own pension plan, the subsidiary would not be required to include the full disclosures required for its parent (the plan sponsor) by ASC 715-20-50.

Appendices

Appendix A: Technical references and abbreviations

The following tables provide a list of the technical references and definitions for the abbreviations and acronyms used throughout this publication.

Technical References

CON 6	FASB Statement of Financial Accounting Concepts No. 6, <i>Elements of Financial Statements a replacement of FASB Concepts Statement No. 3 (incorporating an amendment of FASB Concepts Statement No. 2)</i>
ASC 210	Accounting Standards Codification 210, <i>Balance Sheet</i>
ASC 225	Accounting Standards Codification 225, <i>Income Statement</i>
ASC 230	Accounting Standards Codification 230, <i>Statement of Cash Flows</i>
ASC 250	Accounting Standards Codification 250, <i>Accounting Changes and Error Corrections</i>
ASC 270	Accounting Standards Codification 270, <i>Interim Reporting</i>
ASC 272	Accounting Standards Codification 272, <i>Limited Liability Entities</i>
ASC 310	Accounting Standards Codification 310, <i>Receivables</i>
ASC 320	Accounting Standards Codification 320, <i>Investments—Debt and Equity Securities</i>
ASC 323	Accounting Standards Codification 323, <i>Investments—Equity Method and Joint Ventures</i>
ASC 325	Accounting Standards Codification 325, <i>Investments—Other</i>
ASC 330	Accounting Standards Codification 330, <i>Inventory</i>
ASC 350	Accounting Standards Codification 350, <i>Intangibles—Goodwill and Other</i>
ASC 360	Accounting Standards Codification 360, <i>Property, Plant, and Equipment</i>

Technical References

ASC 410	Accounting Standards Codification 410, <i>Asset Retirement and Environmental Obligations</i>
ASC 450	Accounting Standards Codification 450, <i>Contingencies</i>
ASC 470	Accounting Standards Codification 470, <i>Debt</i>
ASC 480	Accounting Standards Codification 480, <i>Distinguishing Liabilities from Equity</i>
ASC 605	Accounting Standards Codification 605, <i>Revenue Recognition</i>
ASC 715	Accounting Standards Codification 715, <i>Compensation—Retirement Benefits</i>
ASC 720	Accounting Standards Codification 720, <i>Other Expenses</i>
ASC 740	Accounting Standards Codification 740, <i>Income Taxes</i>
ASC 805	Accounting Standards Codification 805, <i>Business Combinations</i>
ASC 810	Accounting Standards Codification 810, <i>Consolidation</i>
ASC 815	Accounting Standards Codification 815, <i>Derivatives and Hedging</i>
ASC 820	Accounting Standards Codification 820, <i>Fair Value Measurement</i>
ASC 825	Accounting Standards Codification 825, <i>Financial Instruments</i>
ASC 835	Accounting Standards Codification 835, <i>Interest</i>
ASC 840	Accounting Standards Codification 840, <i>Leases</i>
ASC 845	Accounting Standards Codification 845, <i>Nonmonetary Transactions</i>
ASC 855	Accounting Standards Codification 855, <i>Subsequent Events</i>
ASC 860	Accounting Standards Codification 860, <i>Transfers and Servicing</i>
ASC 908	Accounting Standards Codification 908, <i>Airlines</i>

Technical References

ASC 915	Accounting Standards Codification 915, <i>Development Stage Entities</i>
ASC 932	Accounting Standards Codification 932, <i>Extractive Activities—Oil and Gas</i>
ASC 940	Accounting Standards Codification 940, <i>Financial Services—Broker and Dealers</i>
ASC 958	Accounting Standards Codification 958, <i>Not-for-Profit Entities</i>
ASC 970	Accounting Standards Codification 970, <i>Real Estate—General</i>
ASC 980	Accounting Standards Codification 980, <i>Regulated Operations</i>
Addendum	Addendum to Accounting Principles Board Opinion No. 2, Accounting Principles for Regulated Industries
Airline Guide	AICPA Audit and Accounting Guide, Airlines
Governments Guide	AICPA Audit and Accounting Guide, State and Local Governments
Investment Companies Guide	AICPA Audit and Accounting Guide, Investment Companies
AICPA Issue Paper	AICPA Issues Paper, Joint Venture Accounting
APB 2	Accounting Principles Board Opinion No. 2, Accounting for the “Investment Credit”
APB 4	Accounting Principles Board Opinion No. 4, (Amending No.2), Accounting for the “Investment Credit”
DIG Issue A5	DIG Issue A5, Definition of a Derivative: Penalties for Nonperformance That Constitute Net Settlement
DIG Issue A6	DIG Issue A6, Definition of a Derivative: Notional Amounts of Commodity Contracts
DIG Issue A8	DIG Issue A8, Definition of a Derivative: Asymmetrical Default Provisions
DIG Issue A10	DIG Issue A10, Definition of a Derivative: Assets That Are Readily Convertible to Cash

Technical References

DIG Issue A11	DIG Issue A11, Definition of a Derivative: Determination of an Underlying When a Commodity Contract Includes a Fixed Element and a Variable Element
DIG Issue A12	DIG Issue A12, Definition of a Derivative: Impact of Daily Transaction Volume on Assessment of Whether an Asset Is Readily Convertible to Cash
DIG Issue A18	DIG Issue A18, Definition of a Derivative: Application of Market Mechanism and Readily Convertible to Cash Subsequent to the Inception or Acquisition of a Contract
DIG Issue A19	DIG Issue A19, Definition of a Derivative: Impact of a Multiple-Delivery Long-Term Supply Contract on Assessment of Whether an Asset Is Readily Convertible to Cash
DIG Issue B14	DIG Issue B14, Embedded Derivatives: Purchase Contracts with a Selling Price Subject to a Cap and a Floor
DIG Issue C10	DIG Issue C10, Scope Exceptions: Can Option Contracts and Forward Contracts with Optionality Features Qualify for the Normal Purchases and Normal Sales Exception?
DIG Issue C15	DIG Issue C15, Scope Exceptions: Normal Purchases and Normal Sales Exception for Certain Option-Type Contracts and Forward Contracts in Electricity
DIG Issue C16	DIG Issue C16, Scope Exceptions: Applying the Normal Purchases and Normal Sales Exception to Contracts That Combine a Forward Contract and a Purchased Option Contract
DIG Issue C20	DIG Issue C20, Scope Exceptions: Interpretation of the Meaning of Not Clearly and Closely Related in Paragraph 10(b) regarding Contracts with a Price Adjustment Feature
DIG Issue G2	DIG Issue G2, Cash Flow Hedges: Hedged Transactions That Arise From Gross Settlement of a Derivative (“All-in-One” Hedges)
EITF 91-6	EITF Issue No. 91-6, Revenue Recognition of Long-Term Power Sales Contracts
EITF 96-17	EITF Issue No. 96-17, Revenue Recognition under Long-Term Power Sales Contracts That Contain both Fixed and Variable Pricing Terms
EITF 98-11	EITF Issue No. 98-11, Accounting for Acquired Temporary Differences in Certain Purchase Transactions That Are Not Accounted for as Business Combinations

Technical References

EITF 99-10	EITF Issue No. 99-10, Percentage Used to Determine the Amount of Equity Method Losses
EITF 01-8	EITF Issue No. 01-8, Determining Whether an Arrangement Contains a Lease
EITF 03-17	EITF Issue No. 03-17, Subsequent Accounting for Executory Contracts That Have Been Recognized on an Entity's Balance Sheet
EITF Topic D-98	EITF Topic No. D-98, Classification and Measurement of Redeemable Securities
FAS 16	FASB Statement No. 16, Prior Period Adjustments
FAS 71	FASB Statement No. 71, Accounting for the Effects of Certain Types of Regulation
FAS 90	FASB Statement No. 90, Regulated Enterprises—Accounting for Abandonments and Disallowances of Plant Costs an amendment of FASB Statement No. 71
FAS 92	FASB Statement No. 92, Regulated Enterprises—Accounting for Phase-in Plans an amendment of FASB Statement No. 71
FAS 116	FASB Statement No. 116, Accounting for Contributions Received and Contributions Made
FAS 133	FASB Statement No. 133, Accounting for Derivative Instruments and Hedging Activities
FAS 144	FASB Statement No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets
FAS 167	FASB Statement No. 167, Amendments to FASB Interpretation No. 46(R)
FIN 18	FASB Interpretation No. 18, Accounting for Income Taxes in Interim Periods—an interpretation of APB Opinion No. 28
FIN 46(R)	FASB Interpretation No. 46 (revised 2003), Consolidation of Variable Interest Entities, an interpretation of ARB No. 51
FSP AUG-AIR-1	FASB Staff Position No. AUG-AIR-1, Accounting for Planned Major Maintenance Activities

Technical References

FSP FAS 115-2	FASB Staff Position Nos. FAS 115-2 and 124-2, Recognition and Presentation of Other-Than-Temporary Impairments
FSP FIN 46(R)-6	FASB Staff Position FIN 46(R)-6, Determining the Variability to Be Considered in Applying FASB Interpretation No. 46(R)
IAS 20	International Accounting Standard 20, Accounting for Government Grants and Disclosure of Government Assistance
IAS 32	International Accounting Standard 32, Financial Instruments: Presentation
IFRIC 4	IFRS Interpretations Committee 4, Determining whether an Arrangement contains a Lease
Proposed FSP ARB 43-a	Proposed FASB Staff Position ARB 43-a, Amendment of the Inventory Provisions of Chapter 4 of ARB No. 43
Proposed PP&E SOP	Proposed Statement of Position, Accounting for Certain Costs and Activities Related to Property, Plant, and Equipment
Proposed Real Estate SOP	Proposed Statement of Position, Accounting for Investors' Interests in Unconsolidated Real Estate Investments
SAB Topic 5.A	Staff Accounting Bulletin Topic 5.A, Expenses of Offering
SAB Topic 5.M	Staff Accounting Bulletin Topic 5.M, Other Than Temporary Impairment of Certain Investments in Equity Securities
SAB Topic 10.A	Staff Accounting Bulletin Topic 10.A, Financing by Electric Utility Companies Through Use Of Construction Intermediaries
SAB Topic 10.C	Staff Accounting Bulletin Topic 10.C, Jointly Owned Electric Utility Plants
SAB Topic 10.D	Staff Accounting Bulletin Topic 10.D, Long-Term Contracts for Purchase of Electric Power
SAB Topic 10.E	Staff Accounting Bulletin Topic 10.E, Classification Of Charges For Abandonments and Disallowances
SAB Topic 10.F	Staff Accounting Bulletin Topic 10.F, Presentation Of Liabilities For Environmental Costs
SOP 78-9	AICPA Statement of Position No. 78-9, Accounting for Investment in Real Estate Ventures

Other Abbreviations

ADIT	Accumulated deferred income taxes
AETR	Annual effective tax rate
AFUDC	Allowance for funds used during construction
AICPA	American Institute of Certified Public Accountants
AOCI	Accumulated other comprehensive income
APB	Accounting Principles Board
ARAM	Average rate assumption method
ARB	Accounting Research Bulletin
ARC	Asset retirement cost
ARO	Asset retirement obligation
ARR	Auction revenue right
ARRA or the Stimulus Bill	American Recovery and Reinvestment Act of 2009
ASC or the Codification	FASB Accounting Standards Codification
California ISO	California Independent System Operator
CFR	Code of Federal Regulations
CIAC	Contributions in aid of construction
COD	Commercial operation date
CPI	Consumer Price Index
CSAPR	Cross-State Air Pollution Rule
CWIP	Construction work in progress
DIG	Derivatives Implementation Group
Dodd-Frank Act	Dodd-Frank Wall Street Reform and Consumer Protection Act of 2010
DOE	U.S. Department of Energy

Other Abbreviations

DTA	Deferred tax asset
EITF	Emerging Issues Task Force
EPC	Engineering, procurement, and construction
ERCOT	Electric Reliability Council of Texas
ERISA	Employee Retirement Income Security Act
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FERC Order 888	FERC Order No. 888, Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities
FERC Order 2000	FERC Order No. 2000, Regional Transmission Organizations
FIN	FASB Interpretation
FinREC	Financial Reporting Executive Committee of the AICPA
FTR	Financial transmission right
FV	Guide to Accounting for Fair Value Measurements: Incorporating ASU 2011-04
GWh	Gigawatt-hour
HLBV	Hypothetical liquidation at book value
Houston Ship Channel	A market hub for natural gas located in Houston, Texas
IAS	International Accounting Standard
IASB	International Accounting Standards Board
IFRIC	IFRS Interpretations Committee
IFRS	International Financial Reporting Standards
IRC	Internal Revenue Code
IRS	Internal Revenue Service
ISO	Independent system operator

Other Abbreviations

ISO New England	ISO New England Inc.
ITC	Investment tax credit
LOCOM	Lower of cost or market
LTSA	Long-term service agreement
MACRS	Modified accelerated cost recovery system
MISO	Midwest Independent System Transmission Operator, Inc.
MMBtu	Million Metric British Thermal Unit
MW	Megawatt
MWh	Megawatt-hour
NERC	North American Electric Reliability Corporation
New York ISO	New York Independent System Operator, Inc.
NRC	Nuclear Regulatory Commission
NYMEX	New York Mercantile Exchange
O&M	Operations and maintenance
OCI	Other comprehensive income
OPEB	Other postemployment benefit
PBTH	Power-by-the-hour
PJM	PJM Interconnection, L.L.C.
PP&E	Property, plant, and equipment
PTC	Production tax credit
REC	Renewable energy credit
RPM	Reliability pricing model
RPS	Renewable portfolio standard
RTO	Regional transmission organization
SAB	Staff Accounting Bulletin
SEC	Securities and Exchange Commission

Other Abbreviations

Section 1603 grant	Grant issued under Section 1603 of the ARRA
SoCal Border	A market hub for natural gas located in California
SOP	Statement of Position
TRA	Tax Reform Act of 1986
Treasury Department	U.S. Department of the Treasury
U.S. GAAP	Accounting principles generally accepted in the United States of America
VIE	Variable interest entity
WREGIS	Western Renewable Energy Generation Information System

Entity names used in this guide

CW&P	Cypress Water & Power Company
DA1	Direct Access Customer 1
DST	Desert Sun Tax Company
FPC	Foxglove Power Company
FPP	Foxglove Power Partners
GGC	Guava Gas Company
IPP	Ivy Power Producers
JPC	Jacaranda Power Company
M&H	M&H Holding Company
PTE	Pine Tree Electric Company
REG	Rosemary Electric & Gas Company
SFP	SunFlower Power Company

Appendix B: Summary of significant changes

This PwC *Utilities and power companies guide* was fully updated as of March 31, 2016. In addition, one topic was updated in December 2018. The following is a summary of the significant changes made in March 2016 and December 2018.

Revisions made in December 2018

UP 20: Regulated operations: business combinations

- **Section 20.4** – Discussion on accounting for merger credits was updated

Revisions made in March 2016

Chapter 2: Leases

- **Section 2.1** – Reference was added for consideration of the guidance in ASC 853, *Service Concession Arrangements*
- **Question 2-5** – Q&A addressing whether pipeline capacity could be subject to a lease was added
- **Section 2.2.3.2** – Considerations regarding contractual restrictions on access to an asset were added
- **Figure 2-3** – Discussion regarding assessment of whether government incentives could be considered output was added
- **Examples 2-5, 2-6 and 2-7** – Additional examples regarding leases without physical delivery were added
- **Questions 2-15 and 2-16** – Q&A's were added to discussion consideration of major maintenance in lease accounting
- **Section 2.5.2.2** – Discussion was added for consideration of whether payments related to the use of renewable facilities are part of minimum lease payments or are contingent rents.

Chapter 3: Derivatives and hedging

- **Question 3-16** – Q&A regarding assessment of whether obtaining flash title is a physical settlement was added
- **Question 3-17** – Q&A assessment of whether a transaction within an ISO would be considered physically settled was added

- **Question 3-31** – Q&A regarding assessment of whether a fully prepaid commodity agreement requires bifurcation of an embedded instrument was added
- **Question 3-32** – Q&A regarding assessment of whether an index related to transportation of a commodity is clearly and closely related to the host contract was added

Chapter 4: Regional transmission organizations

- **Figure 4-11** – Discussion was added to acknowledge the market changes to the Southwest Power Pool and California ISO

Chapter 10: Consolidations: variable interest entities

- The chapter has been updated throughout to reflect the new guidance in ASU 2015-02, *Amendments to the Consolidation Analysis*

Chapter 14: Nuclear power plants

- **Section 14.3.3** – The discussion has been updated for the DOE spent nuclear fuel fees

Chapter 16: Government incentives

- The discussion for ARRA Section 1603 grants in lieu of credits has been removed from the chapter

Chapter 17: Regulated operations

- **Question 17-5** – Q&A on whether a regulated utility can recognize the equity component of a carrying charge as a regulatory asset was added
- **Section 17.3.3.1** – The discussion on alternative revenue programs has been enhanced
- **Section 17.3.3.3** - Discussion on whether costs associated with debt can be recorded as a regulatory asset was added
- **Section 17.4.4** – Discussion on the subsequent accounting for regulatory liabilities was added

Chapter 19: Regulated operations: income taxes

- **Section 19.3.2.5** – Discussion on ASC 740, *Income Taxes* and ratemaking was added

Chapter 20: Regulated operations: business combinations

- **Section 20.4** – Discussion on accounting for merger credits was added

Chapter 21: Presentation and disclosure

- This new chapter was added to aggregate the presentation and disclosure guidance that was previously embedded within each of the chapters

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PwC's National Accounting Services Group

The Accounting Services Group (ASG) within the Firm's National Quality Organization leads the development of Firm perspectives and points of view used to inform the capital markets, regulators, and policy makers. ASG assesses and communicates the implications of technical and professional developments on the profession, clients, investors, and policy makers. The team consults on complex accounting and financial reporting matters and works with clients to resolve issues raised in SEC comment letters. They work with the standard setting and regulatory processes through communications with the FASB, SEC, and others. The team provides market services such as quarterly technical webcasts and external technical trainings, including our alumni events. The team is also responsible for sharing their expert knowledge on topics through internal and external presentations and by authoring various PwC publications. In addition to working with the US market, ASG also has a great deal of involvement in global issues. The ASG team has a large global team that is deeply involved in the development of IFRS, and that has developed a strong working relationship with the IASB. The team of experienced Partners, Directors, and Senior Managers helps develop talking points, perspectives, and presentations for when Senior Leadership interacts with the media, policy makers, academia, regulators, etc.

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