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Memo

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Project  EITF Issue No. 15-A, “Application of the Normal Purchases and Normal Sales Scope Exception to Certain Electricity Contracts within Nodal Energy Markets”

Project Stage  Initial Deliberations

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Previously discussed by EITF

Previously distributed Memo Numbers  None

Purpose or Objective of This Memo

1. The purpose of this memo is to assist the Task Force in determining whether certain contracts for the physical delivery of electricity on a forward basis within a nodal energy market should meet the physical delivery criterion of the normal purchases and normal sales (NPNS) scope exception to derivative accounting in Topic 815, Derivatives and Hedging.

*The alternative views presented in this Issue Summary are for purposes of discussion by the EITF. No individual views are to be presumed to be acceptable or unacceptable applications of Generally Accepted Accounting Principles until the Task Force makes such a determination, exposes it for public comment, and it is ratified by the Board.
**Background Information**

*Power Industry Background*

2. Electricity is a physical energy commodity that generally cannot be stored for future use at a scale that is commercially viable. Accordingly, electricity must be produced and delivered to end users in real time as it is demanded and consumed. In order to maintain the integrity of the electricity system, it is necessary to assure that a supply and demand balance exists on a system-wide basis as well as across the many points in the system where electricity may be delivered or withdrawn.

3. Historically, power companies throughout the U.S. have built, owned, and operated their own transmission systems in such a manner as to assure that electricity consumed was balanced with the supply of electricity generated, either by their own plants or by purchases from others. During the first half of the 20th century, power companies formed “interconnection” groups whereby several companies in the same geographic region connected their systems together. This linkage of systems improved reliability and efficiency by allowing participating power companies to access power supplies from multiple sources. These interconnection groups operated the electricity grid of the participating power companies for the benefit of all the companies in the group, assuring that supply and demand was balanced over the entire grid.

4. In the late 20th century, changes in U.S. energy policy encouraged (a) the unbundling of interstate electricity transmission facilities (high voltage power lines) from other parts of the power generation and delivery supply chain; (b) operation of those transmission facilities on a functionally independent basis to promote open access to the grid; and (c) greater use and formalization of interconnection groups on a regional basis. One of the reasons for this policy was to promote competition in wholesale power prices and thereby lower the overall cost of electricity. This was to be achieved by encouraging power companies to join a Regional Transmission Organization (RTO), and, together with all other members\(^1\) of that RTO, authorize the day-to-day operations of the grid to be

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\(^1\) The members of an RTO or ISO include companies such as independent power producers/generators, electric cooperatives, independent transmission companies, power marketers, and municipalities.
managed by an Independent System Operator (ISO). For simplicity, the acronym ISO is used throughout this memo to refer to this arrangement.

5. As a result of that policy, ISOs administer wholesale power markets in multiple regions in order to offer non-discriminatory access to the grid to all qualified market participants, thereby potentially increasing the volume of power transactions, and creating liquidity and market price transparency using economically sophisticated pricing approaches (discussed below). Just as with interconnection groups, ISOs do not own the transmission system or generation facilities but instead have their own set of employees that manage and operate the grid. The transmission systems and generation facilities are owned by other market participants (for example, independent transmission companies and independent power producers). In essence, the ISO structure turned the electricity grid into a common carrier that provides electricity transmission services to any qualified market participant. The ISO does not generate, market, or trade electricity for its own account. Rather, its activities are designed and required to be both profit neutral and quantity balanced. ISOs are typically organized as not-for-profit corporations and are regulated by various governmental agencies, including the Federal Energy Regulatory Commission (FERC).

6. This evolution in the wholesale power markets has resulted in changes in the way usage of an ISO-operated grid (that is, transmission) is priced. A simplified diagram of an ISO is illustrated in Appendix 15-AA.

*Market Pricing Overview*

7. The price a market participant pays to use the grid typically includes the following (among other items):

   a. A transmission service charge designed to compensate transmission line owners for usage of their lines. These charges are based on established tariffs and are passed through the ISO to the transmission line owners.

   b. An administrative service charge designed to cover the ISO’s administrative and operating costs. These charges are also based on established tariffs.

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2 Some non-ISO grids still exist; however, this Issue is not relevant to transactions within those markets.
c. The difference between locational marginal pricing (LMP) at the delivery and withdrawal locations at the time of delivery multiplied by the quantity of power transmitted between them.

8. This Issue focuses on the LMP difference component since that is the component that has resulted in questions about an entity’s ability to assert the NPNS scope exception to derivative accounting, as described further below. LMP is a methodology under which the ISO assigns a price for electricity at each specific location (referred to as a node or delivery point) on the grid where electricity can be delivered or withdrawn. Most ISO-operated electricity grids have hundreds or thousands of individual nodes located at generator sites, consumer sites, and aggregation points (which, in totality, are a “nodal energy market”). ISOs may also compute a price for a hub location that is an average of the LMP at several nodes within a geographic area on the grid. The use of a hub price promotes market liquidity, which, in turn, promotes price transparency and economic efficiency.

9. LMPs are essentially spot market prices at the respective nodes. Unlike other market prices that are determined based upon the clearing price that matches buyers with sellers, LMPs are determined by the ISO for each node based on the economic impact of physical supply, demand, and transmission capacity availability, including congestion. Congestion results when the lowest-priced electricity cannot flow freely to a specific node because of supply, demand, and physical transmission capacity constraints. That is, congestion results when requests for usage of a particular node exceed available capacity. The LMP is higher at nodes that are more congested and lower at nodes that are less congested. Thus, the difference between the LMP at the delivery and withdrawal locations could be positive or negative requiring the ISO to charge or credit a market participant for their usage of the grid.

10. Invoices from the ISO to market participants for their use of the grid sometimes refer to deliveries of electricity to the grid as a “sale” or “credit” to the ISO and withdrawals of electricity from the grid as a “purchase” or “charge” from the ISO. However, as noted above, as the grid operator, the ISO does not generate, store, or use the electricity that flows through the transmission system. The ISO must separately calculate the LMP at
each node on a gross basis because prices and quantities of electricity delivered or consumed both change hourly.

11. Within an ISO-operated nodal energy market, it is not possible to reserve path-specific transmission capacity on a forward basis. Prior to the formation of ISOs, and consistent with certain other commodity markets today, market participants could use either owned transmission systems or reserve transmission capacity along certain paths.

*Title Transfer*

12. Prior to the 2008 credit crisis, ISOs did not take title when they provided transmission service within the grid. However, subsequent to the 2008 credit crisis, the FERC concluded that the credit practices of ISOs needed to be strengthened to minimize credit risk because credit losses are charged back to the ISO’s members (that is, if one member defaults it would affect all the members of the ISO).

13. As a result of directives from FERC, many ISOs have begun taking title for purposes of reducing credit risk to their members. Taking title enables ISOs to legally offset the defaulting party’s receivables from the ISO against payables so that the ISO (acting on behalf of its members) only has credit exposure for the net amount.

*Application of normal NPNS scope exception to certain electricity contracts within nodal energy markets*

14. A contract for the physical delivery of electricity on a forward basis meets the definition of a derivative under Topic 815 when it has all of the following characteristics:

a. An underlying (typically in the form of the price of electricity)

b. A notional amount (typically in the form of a stated volume of megawatt-hours)

c. No initial net investment

d. Net settlement (typically in the form of either an asset that is readily convertible to cash or a market mechanism when there is a liquid market for the electricity)
15. Derivative contracts must be recorded at fair value as an asset or liability with changes in fair value recognized through earnings (or other comprehensive income if the derivative qualifies for cash flow hedge accounting) unless the contract qualifies for a scope exception.

16. During the Board’s deliberations of FASB Statement No. 133, Accounting for Derivative Instruments and Hedging Activities, the Board realized that its broad definition of a derivative would encompass certain contracts for the physical delivery of nonfinancial assets that are not unlike binding purchase orders. The Board did not intend to change the accounting for those types of contracts because it believed that they were more akin to executory purchase or sale contracts. Consequently, the Board decided to provide the NPNS scope exception to derivative accounting.

17. Topic 815 has two discrete sets of criteria that companies in the utility industry may consider in order to meet the NPNS scope exception.

   a. General – Any contract may qualify for the NPNS scope exception by meeting the applicable criteria in paragraphs 815-10-15-22 through 15-44 (see Appendix 15-AB).

   b. Capacity contracts – A power purchase or sales agreement that is a capacity contract qualifies for the NPNS scope exception if the criteria in paragraphs 815-10-15-45 through 15-51 are met (see Appendix 15-AC). A capacity contract is a contract entered into to meet a buyer’s obligation to maintain sufficient capacity established by a regulatory commission, local standards, regional reliability councils, or RTOs. Under this guidance, capacity contracts may qualify for the NPNS scope exception even when they contain optionality on the quantity of electricity to be delivered, and even when they are subject to unplanned or unintentional netting. These characteristics are common for capacity contracts and would otherwise disqualify a contract from meeting the general NPNS scope exception. The Board decided to extend the NPNS scope exception to capacity contracts after considering certain unique characteristics of

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3 This guidance originated from DIG Issue C15, “Scope Exceptions: Normal Purchases and Normal Sales Exception for Certain Option-Type Contracts and Forward Contracts in Electricity.”
the electric industry (namely, the impact of deregulation on the way power contracts are structured, the fact that electricity cannot be readily stored in significant quantities, and the fact that many suppliers are statutorily or contractually obligated to maintain a specified level of electricity supply to meet fluctuating demand and, therefore, buyers need some flexibility in determining when to take electricity and in what quantities).

18. Both sets of NPNS criteria include a requirement related to physical delivery; however, there are nuanced differences in the guidance, as discussed in the staff analysis below.

19. Questions have arisen as to whether forward contracts for the physical delivery of electricity within a nodal energy market where one of the counterparties incurs LMP charges (or credits) payable to (or receivable from) the ISO should meet the physical delivery criterion of NPNS. These questions relate to the accounting by the counterparties to the forward contract (that is, entities other than the ISO).

20. For example, if a retail electric utility enters into a forward purchase contract with a power generator to deliver electricity to a liquid price hub (not directly to its customer load zone) and then incurs charges from the ISO to transmit the electricity from the liquid price hub to its customer load zone, has the retail electric utility purchased physical electricity from the power generator and simply incurred a transmission charge? Or has the retail electric utility, in substance, purchased electricity from the ISO (not the power generator) at its customer load zone and used the forward purchase contract with the power generator to hedge its pricing risk? These questions arise because of (a) the use of nodal LMPs as a pricing mechanism to determine a component of the transmission charge, (b) the gross calculation of charges and credits on the ISO bill, (c) the physical delivery of electricity purchased to liquid pricing locations (rather than directly to the retail utility company’s customer load zone), and (d) recent changes in title transfer in certain ISO markets. Currently, there is diversity in practice. A utility industry trade group performed a survey noting that 10 of the 12 respondents indicated that they apply the NPNS scope exception for these types of contracts, while the other two respondents did not think these types of contracts qualify for the NPNS scope exception under the current guidance.
Outreach

21. The staff’s outreach with large accounting firms confirmed that there is diversity in practice underlying this Issue. The staff discussed this Issue with one of the FASB Investor Liaisons who indicated that past discussions with users indicated that users generally do not believe that derivative accounting (where revenue and cost of sales transactions are marked-to-market) is decision-useful, particularly when the transactions are routine. The staff also discussed this Issue with an energy industry accounting analyst at a large credit ratings agency who held this same view.

Example Fact Pattern

22. PowerCo is a retail electric utility company engaged in the supply, transmission, and distribution of electricity to end users in the PJM Interconnection (PJM). PJM is an ISO that operates a nodal energy market covering 13 Mid-Atlantic States and the District of Columbia. PowerCo does not own electric generating facilities in PJM and, therefore, must purchase wholesale power for resale to its end user customers.

23. PowerCo’s end user customer load zone is located at Location A. While Location A is physically capable of receiving delivery of all of the electricity used by PowerCo’s customers, Location A has relatively illiquid forward prices compared to some other delivery points within PJM. That illiquidity is because Location A is not a location where many buyers and sellers other than PowerCo transact.

24. As a consequence, PowerCo enters into a fixed price forward contract with a power generator to purchase electricity for physical delivery at a more liquid point in PJM (Location B, which is a hub). The forward purchase contract requires physical delivery of electricity into the grid during a specified delivery period. PJM has the physical capacity to deliver all of PowerCo’s physical electricity purchases from Location B to Location A.

25. During the specified delivery period, PowerCo receives delivery into the grid of the physical electricity it purchased under the forward purchase contract at Location B and sells physical electricity to its customers at Location A. PJM computes the transmission charge for delivery from Location B to Location A by multiplying the quantity of electricity PowerCo receives from its supplier at Location B by the LMP at that location.
and subtracting the product of the quantity of electricity PowerCo delivers to its customers at Location A and the LMP at that location.

26. To further illustrate, assume that the forward contract provides for PowerCo to purchase 100 thousand megawatt-hours (MWhs) from its supplier at a price of $45 per MWh. Also assume that the LMPs are $44.50 at Location B and $46.00 at Location A at the time the electricity is delivered. Based on those amounts, the cash flows from the transaction are as follows:

a. Cash paid by PowerCo to supplier:
   (i) $45 fixed price × 100 thousand MWh = $4,500,000

b. Cash paid by PowerCo to ISO:
   (i) $46 LMP at Location A × 100 thousand MWh = $4,600,000

   Less
   $44.50 LMP at Location B × 100 thousand MWh = $4,450,000

   (ii) Net cash paid by PowerCo to ISO = $150,000

c. Total cash paid by PowerCo for electricity at Location A = $4,650,000 (or $46.50 per MWh)

27. The fixed price forward contract meets the definition of a derivative under Topic 815.

28. The example above is used for illustrative purposes throughout this memo. The example relates to a forward contract, however, this Issue also applies equally to option contracts and to forward contracts that contain optionality. That is, contracts with volumetric optionality are eligible for the NPNS scope exception if they are capacity contracts and meet the criteria in paragraphs 815-10-15-45 through 15-50, including the criterion related to physical delivery. Additionally, the example focuses on a buyer’s application of the NPNS scope exception; however, the Issue also could apply to sellers of electricity. For example, power generators may sell electricity forward for delivery to a location within the ISO as opposed to the point where their generation facility connects to the ISO-operated grid. In those cases, the power generator will incur LMP charges (or credits) to
transmit their electricity, and the same accounting question related to physical delivery applies to those transactions.

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<th>Question 1 for the Task Force</th>
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<td>1. Does the Task Force believe that a contract for the physical delivery of electricity on a forward basis within a nodal energy market in which one of the counterparties incurs LMP charges (or credits) payable to (or receivable from) the ISO should meet the physical delivery criterion of the NPNS scope exception?</td>
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**Staff Analysis**

29. Two alternative views have been observed in practice:

   a. **Alternative 1** – Forward electricity contracts for physical delivery within a nodal energy market operated by an ISO in which one of the counterparties incurs LMP charges (or credits) in connection with the transmission of the electricity, should not meet the physical delivery criterion and, therefore, those contracts should not be eligible for the NPNS scope exception.

   Under this alternative, PowerCo would record the forward contract at fair value as an asset or liability each period until settlement, with the change in fair value recognized through earnings, other comprehensive income if the contract qualifies for cash flow hedge accounting, or regulatory assets (liabilities) if the company is within the scope of Topic 980, *Regulated Operations*.

   b. **Alternative 2** – Forward electricity contracts for physical delivery within a nodal energy market operated by an ISO in which one of the counterparties incurs LMP charges (or credits) in connection with the transmission of the electricity, should meet the physical delivery criterion and, therefore, those contracts should be eligible for the NPNS scope exception.

   Under this alternative, if PowerCo elects to designate the contract as NPNS it would be treated as an executory purchase contract; therefore, no journal entries would be recorded until the electricity is delivered.
30. A decision to make forward electricity contracts for physical delivery within nodal energy markets *eligible* for the NPNS scope exception does not, in and of itself, make the NPNS scope exception *available* for those types of contracts since this Issue only addresses the criterion related to physical delivery. Reporting entities would need to evaluate other NPNS criteria to determine whether the scope exception can be applied.

*Alternative 1: Electricity contracts for physical delivery within nodal energy markets should not meet the physical delivery criterion of the NPNS scope exception*

31. Proponents of Alternative 1 believe that PowerCo is taking delivery of electricity at Location B and immediately selling it to the ISO in the spot market based on the LMP at Location B. Then, PowerCo is viewed as purchasing the power it needs to serve its customers in the spot market at Location A based on the LMP at Location A.

32. Proponents of this view point out that when a commodity is delivered to a liquid market hub pursuant to a forward purchase contract and the delivered commodity is immediately sold at the hub to another party, the forward contract is typically deemed not to meet the physical delivery criterion (that is, the instantaneous flow-through of title caused by the purchase and sale of electricity at the same time at Location B (“flash title”) does not constitute physical delivery). Consequently, proponents of this view believe that the transaction with the ISO precludes application of the NPNS scope exception. These proponents believe that the ISO is acting as a principal in the transaction because it takes title to the electricity it transmits. They also believe that the form of ISO bills, which often refer to “purchases” and “sales,” supports that view.

33. Proponents of this view do not believe that the amount paid to the ISO represents a transportation charge because it is determined in part based upon the difference between the LMP (which is essentially a spot market price) at the delivery and withdrawal locations. Transportation arrangements in other industries are usually priced solely based upon the cost of transportation plus a profit margin, or factors other than the market price of the product being transported.

34. GAAP related to the general NPNS scope exception for forward (non-option-based) contracts currently states that “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” (paragraph 815-10-15-41). Proponents of this view believe that this guidance precludes asserting NPNS under these criteria because the contract with the supplier to purchase electricity and the arrangement with the ISO to transmit the electricity constitute a “series of sequential contracts intended to accomplish ultimate acquisition or sale of a commodity” (that is, there is one contract with the supplier, and another with the ISO). The staff notes that the Derivatives Implementation Group’s rationale for not permitting these contracts to qualify for the NPNS scope exception was that they concluded the exception should only apply to a single contract under which delivery is made, such as a binding purchase or sale order. Because delivery is not made to the purchaser pursuant to each of the sequential contracts, all but the last contract pursuant to which delivery to the purchaser is ultimately made must be accounted for as derivatives. The sequential contracts guidance only applies to forward contracts that are not designated as capacity contracts under paragraphs 815-10-15-45 through 15-50.

35. Because physical delivery of the electricity under the forward contract does not occur at PowerCo’s customer load zone and only the last transaction in a series of sequential contracts can be the “normal purchase or sale,” proponents of View A believe that it is clear that these transactions do not meet the NPNS scope exception criteria that exists today (at least for contracts that are not designated as capacity contracts).

36. Proponents of this view believe that the forward purchase at Location B is ultimately used to hedge the price of physical power at Location A. As such, the forward purchase of power at Location B may qualify as an effective cash flow hedge of PowerCo’s exposure to changes in prices at Location A, but would not qualify for application of the NPNS scope exception.

37. Further, proponents of this view point out that the purchasers of electricity are not required to transact at a location other than their customer load zone. That is, in the example fact pattern, PowerCo could have purchased electricity at the more illiquid Location A and the physical delivery criterion of the NPNS scope exception would be met. Although the cost of transacting at an illiquid location may be higher than at a liquid
location, there are no regulatory, legal, or physical restrictions that would limit this ability. However, the staff notes that if the supplier delivered to Location A, the same questions raised in this Issue would be relevant to the supplier’s ability to apply the NPNS scope exception to the forward sales contract.

38. A mark-up of the proposed guidance to reflect Alternative 1 within the Codification is included in Appendix 15-AD.

*Alternative 2: Electricity contracts for physical delivery within nodal energy markets should meet the physical delivery criterion of the NPNS scope exception*

39. Proponents of Alternative 2 believe that in both economic substance and physical performance, PowerCo has purchased and received electricity from the supplier, paid the ISO for the transmission of that electricity, and delivered that electricity to its end-use customers. Consequently, they believe that the physical delivery criterion has been met.

40. PowerCo’s intent is not to convert electricity purchased under the forward contract to cash when it is delivered to Location B or otherwise to use the forward contract to be speculative in nature. That is, PowerCo’s intent is not to effectively net settle the forward contract by converting the electricity to cash at Location B. PowerCo must acquire sufficient physical quantities of electricity to serve its end-use customers, and using an ISO for transmission is the only way PowerCo can buy power for delivery through the ISO-operated electricity grid. Each delivery of electricity into the ISO is accompanied by a contemporaneous withdrawal, which demonstrates that the actual result is for PowerCo to accept physical delivery of the electricity. Physical delivery is evidenced by the consumption of the electricity by PowerCo’s customers at Location A since all other sources and uses of power within the grid are balanced. Because the contract resulted in the physical delivery of nonfinancial assets, proponents of Alternative 2 believe that it is consistent with the Board’s intent to provide a scope exception to derivative accounting for contracts similar to binding purchase orders.

41. Proponents of this view acknowledge that the forward purchase contract is for delivery to a location other than its customer load zone; however, they do not believe that this should preclude eligibility for the NPNS scope exception. Physical transacting at a liquid hub with transportation to end users is customary and common in ISOs. It has never been
physically possible to generate all the power needed at the same location where it is used, therefore, the grid is necessary to move electricity from where it is generated to where it is consumed. These proponents believe that the purpose of market participants’ transactions with an ISO is to arrange a physical transportation service, not to sell its electricity at the supplier’s delivery point (Location B in the example) only to repurchase the electricity at the customer load zone (Location A in the example).

42. Before the conversion to a nodal energy market, entities could procure electricity on a forward basis, transmit that electricity to their customer load zone using reserved (or owned) transmission capacity, and elect the NPNS scope exception (assuming all other criteria were met) to the forward purchase contract. Likewise, in other commodity industries (for example, natural gas), purchasers can reserve transportation capacity from a liquid delivery location to the point where the commodity will ultimately be used and potentially apply the NPNS scope exception. In a nodal energy market, real-time transmission is the only option for moving power within the ISO. Consequently, these proponents argue that because the physical nature of electricity delivery has not changed, and because the substance and ultimate objective of forward electricity purchase contracts are similar to other commodity industries where transportation capacity can be reserved, forward contracts to transact in nodal energy markets should be eligible for the NPNS scope exception.

43. Proponents of this view believe that the ISO’s billing convention of referring to “purchases” and “sales” is a computational necessity to show that the transmission charge is based in part on LMPs at each location multiplied by quantities delivered. They believe that these terms are simply a means to price the ISO’s transmission services and that they do not change the substance of the arrangement, which is the purchase of physical power at Location B for transport and delivery to Location A where it is withdrawn by its end-use customers. The fact that the pricing in the nodal energy markets is presented through the terminology of a “sale” and “purchase” is a reflection of the ISO’s administrative mechanism, not the physical transaction.

44. Proponents of this view point out that transactions with an ISO are not grossed-up on the income statement in the purchaser’s financial statements. For example, if the substance of
the transaction was that PowerCo purchased electricity from a supplier that it resold to the ISO and then it purchased electricity from the ISO that it resold to its customers, some may argue that PowerCo would gross up its income statement for two purchases (one from the supplier at Location B and one from the ISO at Location A) and two sales (one to the ISO at Location B and one to its customers at Location A). These proponents do not believe that a gross-up on the income statement in the purchaser’s financial statements represents the substance of these types of transactions.

45. Proponents of this view acknowledge that there are no requirements that a purchaser of electricity transact at a location other than their customer load zone. However, they point out that for a given transaction to move electricity through an ISO-operated grid, there is always one entity that is required to pay the ISO a transmission charge. For example, instead of purchasing electricity at Location B, PowerCo could have arranged for delivery from the supplier at Location A. In this case, the supplier would be required to pay the ISO for the transmission between Location B and Location A, thus the same questions raised in this Issue would be relevant to the supplier’s ability to apply the NPNS scope exception to the forward sales contract.

46. GAAP related to the NPNS scope exception for capacity contracts currently requires that only the terms of the contract require physical delivery of electricity (paragraph 815-10-15-45(a)(1)). That is, the contract cannot be net settled under contractual terms. Proponents of this view argue that, at least for capacity contracts, GAAP currently allows the NPNS scope exception for contracts for the delivery into nodal energy markets because the contract between PowerCo and the supplier requires physical delivery to Location B and does not permit contractual net settlement between PowerCo and the supplier. However, despite that guidance, there is currently diversity in practice about whether capacity contracts for delivery in nodal energy markets meet the physical delivery criterion. Furthermore, even if one were to conclude that today’s physical delivery criterion was met for capacity contracts, many contracts to purchase electricity in nodal energy markets are not capacity contracts. Proponents do not believe that there should be a difference between the accounting treatment for capacity contracts and non-capacity contracts as it relates to this Issue because the substance of the transaction is the same in both circumstances.
47. Proponents of this view acknowledge that the contract with the supplier to purchase electricity and the arrangement with the ISO to transmit the electricity could be considered a “series of sequential contracts” under paragraph 815-10-15-41 (as described in Alternative 1), thereby precluding an entity from asserting NPNS under these criteria. However, they do not believe that this guidance was intended for the transactions described in this Issue. They believe that this guidance was intended for a series of purchase and sale contracts, and that the transactions described in this memo are composed of a single purchase contract with the supplier and a separate transmission arrangement with the ISO. They also believe that nodal energy markets are unique because using an ISO for transmission is the only way to move power through an ISO-operated electricity grid.

48. A mark-up of the proposed guidance to reflect Alternative 2 within the Codification is included in Appendix 15-AE.

**Staff Recommendation**

49. The staff recommends Alternative 2 primarily on the basis that the substance of these contracts requires the physical delivery of electricity for resell to end-use customers. The staff believes that its recommendation is consistent with the Board’s intent in providing the NPNS scope exception for contracts for the physical delivery of nonfinancial assets that are not unlike binding purchase orders.

50. Prior to the evolution to nodal energy markets, companies could use either owned transmission systems or reserve transmission capacity along certain paths (similar to the natural gas example above) and elect to apply the NPNS scope exception assuming all other criteria were met. Because there has been no change in the physical nature of electricity transmission before and after the evolution to nodal energy markets, the staff does not believe that such an evolution should prevent companies from being able to elect to apply the NPNS scope exception.

51. Although the transmission charge payable to the ISO is calculated based in part upon the difference between market prices at the delivery and withdrawal locations and many ISOs now take title to the electricity during transmission, the staff does not view the ISO as a
market participant engaged in the buying and selling of electricity. The transfer of title to and from the ISO is instantaneous and is recognized by the FERC, ISOs, and other market participants as being separate and distinct from the forward energy contract. That is, ISOs are not viewed as a market participant when executing their role of providing transmission service across the grid but, rather, are a facilitating counterparty.

52. The staff does not believe that the transmission charge payable to the ISO constitutes net settlement of the forward purchase contract. Because the transmission charge is payable to the ISO rather than the supplier, it should not be viewed as net settling the forward purchase contract. Furthermore, using the example fact pattern, if the forward purchase contract were truly net settled (between the counterparties that entered into the forward purchase contract), it would have resulted in a $50,000 loss (calculated as the difference between cash paid under the fixed price forward contract of $4.5 million and the value of electricity received at Location B of $44.5 million), which is different than the $150,000 transmission charge payable to the ISO.

53. The staff acknowledges that this Issue has similarities to contracts for the delivery of commodities in other industries. However, in those other industries, companies typically have the ability to reserve transportation capacity in advance and those contracts may be eligible to qualify for the NPNS scope exception. For example, a Houston refiner may purchase natural gas on a forward basis for delivery at Henry Hub, and arrange for transportation of that natural gas to its Houston refinery. Because the Houston refiner retains title to the natural gas during shipment from Henry Hub to Houston, questions about the physical delivery criterion don’t typically arise. Therefore, the Houston refiner may designate the forward purchase contract as NPNS assuming all other criteria are met. If, on the other hand, the Houston refiner enters into a series of buy and sell contracts with different counterparties for the ultimate delivery of natural gas in Houston, only the last contract in that series of contracts may be eligible for the NPNS scope exception. Consequently, in other industries, companies have more latitude in how to structure contracts to arrange for physical delivery to a particular location. In a nodal energy market, there is no other way to transact. That is, transmission capacity cannot be reserved, and the only way to transmit power is through the ISO-operated electricity grid.
54. Disallowing contracts within the scope of this Issue from being eligible for the NPNS scope exception would result in a significant number of routine transactions being accounted for as derivatives. For some companies, that would result in derivative gains (or losses) being recognized prior to physical delivery, which would ultimately increase (or decrease) the cost of electricity recognized upon delivery. For regulated companies within the scope of Topic 980, that could result in a balance sheet gross up of derivative assets (liabilities) and regulatory assets (liabilities) prior to physical delivery. The staff does not believe that this accounting is consistent with the nature and economics of a physical transaction.

55. The staff notes that the Board has considered the unique characteristics of the utility industry in past standard setting activities. For example, in DIG Issue C15, the Board provided relief from derivative accounting for certain capacity contracts that contain volumetric optionality. Its basis for providing that relief was because electricity cannot be readily stored in significant quantities and the entity selling electricity is obligated to maintain sufficient capacity to meet the electricity needs of its customer base (therefore, electricity contracts often necessarily provide flexibility in determining when to take electricity and in what quantity in order to match power to fluctuating demand).

Disclosure

56. There is no specific disclosure guidance in Topic 815 for contracts that are designated as NPNS since, by definition, these contracts are considered “normal” in relation to a company’s business. However, these contracts would be subject to disclosure requirements of other applicable GAAP. Additionally, Topic 235 requires disclosures of significant accounting policies, including accounting methods that involve a selection from existing acceptable alternatives, such as NPNS.

57. Topic 815 has extensive quantitative and qualitative disclosure requirements for derivative contracts. These requirements are designed to help financial statement users understand (a) how and why an entity uses derivative instruments, (b) how derivative instruments and related hedging items are accounted for, and (c) how derivative
instruments and related hedging activities affect an entity’s financial position, financial performance, and cash flows.

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<td>2. Does the Task Force believe that any incremental disclosures should be required?</td>
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</tbody>
</table>

**Staff Analysis and Recommendation**

58. The staff does not recommend any incremental disclosures for this Issue. The staff believes that the disclosure requirements for contracts within the scope of this Issue should be the same as the disclosure requirements for contracts outside the scope of this Issue. That is, if the Task Force decides these contracts should be eligible for the NPNS scope exception, companies should be subject to the disclosure requirements of other applicable GAAP. If the Task Force decides these contracts should be accounted for as derivatives, companies should be subject to Topic 815’s disclosure requirements.

**Transition**

59. Because reasonable transition alternatives may be different depending upon the Task Force’s decision on Question 1, this discussion is broken out accordingly.

<table>
<thead>
<tr>
<th>Questions 3 and 4 for the Task Force</th>
</tr>
</thead>
<tbody>
<tr>
<td>3. Does the Task Force want to require prospective transition, retrospective transition, or modified retrospective transition?</td>
</tr>
<tr>
<td>4. Does the Task Force want to allow the option of retrospective transition?</td>
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</tbody>
</table>

**Transition method if the Task Force chooses Alternative 1** (Electricity contracts for physical delivery within nodal energy markets should **not** meet the physical delivery criterion of the NPNS scope exception, and, thus, entities that previously applied the NPNS scope exception would no longer be permitted to do so)

**Staff Analysis**

*View A – The effects of initially adopting the guidance in this Issue as of the effective date should be applied on a prospective basis.*
60. View A would require application of the guidance in this Issue to all contracts that are entered into on or after the effective date. Therefore, new contracts entered into on or after the effective date would be accounted for as derivatives.

61. Under Topic 815, NPNS is an election that can be made on a contract-by-contract basis at the inception of the contract or at a later date. However, once elected, a company is not permitted to change its election and treat the contract as a derivative. Consequently, under prospective transition, contracts designated as NPNS before the effective date would continue to be designated as NPNS after the effective date.

62. Proponents of View A point out that it would result in the lowest cost to preparers because it only applies to new contracts entered into on or after the effective date.

63. Opponents of View A point out that it would result in inconsistency between financial statement periods for companies that currently designate contracts within the scope of this Issue as NPNS. In addition, there would continue to be a lack of comparability among companies for periods after the effective date until all contracts that were designated as NPNS before the effective date are settled. Because some electricity contracts are long-term, prospective transition could result in a lack of comparability for a long period of time. Opponents point out that prospective transition would not resolve the diversity in practice that exists among companies for periods prior to the effective date.

64. Opponents also point out that it may be unclear how to account for contracts designated as NPNS before the effective date that are modified after the effective date. For example, if a contract is modified after the effective date to increase the quantities purchased under the contract, and it is probable those quantities will be physically delivered, entities may be unsure about whether the contract continues to qualify for the NPNS scope exception.

65. View B – The effects of initially adopting the guidance in this Issue as of the effective date should be applied on a retrospective basis.

65. View B would require application of the guidance in this Issue to all existing and previously settled contracts, as well as to new contracts entered into on or after the effective date. Therefore, preparers that previously designated contracts as NPNS would be required to retrospectively determine the fair value of those contracts for each
historical reporting period and revise their historical financial statements to include the mark-to-market effects of those derivative contracts.

66. Proponents of View B point out that it could result in the most comparability among companies and consistency between financial statement periods of all the transition methods.

67. Opponents of View B point out that it is the most costly transition method because it would require retrospective determinations of fair value and revisions of historical financial statements. That process could be burdensome for preparers, particularly for those that do not have readily available systems and information necessary to develop fair value estimates (for example, forward price curves as of the end of each historical financial reporting period).

View C – The effects of initially adopting the guidance in this Issue as of the effective date should be applied on a modified retrospective basis.

68. View C would require application of the guidance in this Issue to all contracts existing on the effective date, as well as to new contracts entered into after the effective date, through a cumulative effect adjustment. Therefore, preparers that previously designated contracts as NPNS would be required to determine the fair value of those contracts as of the effective date and recognize derivative assets and/or liabilities through a cumulative-effect adjustment to the opening balance of retained earnings as of the beginning of the year, in the period of adoption.

69. Proponents of View C point out that it would result in comparability among companies for all periods after the effective date. In addition, it is less costly than retrospective transition because it would not require retrospective determinations of fair value or revisions of historical financial statements.

70. Opponents of View C point out that it would result in inconsistency between financial statement periods for companies that currently designate contracts within the scope of this Issue as NPNS. It would also not resolve the diversity in practice that exists among companies for periods prior to the effective date.
Staff Recommendation

71. The staff recommends View C, primarily because modified retrospective transition would be less costly than retrospective transition and would increase comparability among companies for all periods after the effective date. Furthermore, this transition method is consistent with the transition framework established by the Derivatives Implementation Group in Statement 133 Implementation Issue K5, “Miscellaneous: Transition Provisions for Applying the Guidance in Statement 133 Implementation Issues” (DIG K5) for contracts that were not previously accounted for as derivatives but are accounted for as derivatives under newly issued implementation guidance.

72. The staff also recommends that companies be given the option of applying retrospective transition because it could result in the most consistency between financial statement periods.

Transition method if the Task Force chooses Alternative 2 (Electricity contracts for physical delivery within nodal energy markets should meet the physical delivery criterion of the NPNS scope exception, and, thus, entities that did not previously apply the NPNS scope exception would be permitted to do so)

Staff Analysis

View A – The effects of initially adopting the guidance in this Issue as of the effective date should be applied on a prospective basis.

73. View A would require application of the guidance in this Issue to all contracts that are entered into on or after the effective date. Therefore, contracts entered into on or after the effective date would be eligible for the NPNS scope exception. Notwithstanding the method of transition chosen by the Task Force, the staff points out that, because the NPNS scope exception is an election that can made be at inception of the contract or at a later date, preparers would always have the ability to designate a qualifying contract that was entered into before the effective date on or after the effective date. Thus, under View A, any qualifying contract could be initially designated as NPNS on or after the effective date.
date. Said another way, this guidance would be applied to any elections made (either for existing or new contracts) after the effective date.

74. Companies that designate a contract as NPNS after the contract’s inception date would cease marking the contract to market and would prospectively account for the carrying value of the derivative at the time of designation under other applicable GAAP.

75. Because NPNS is an election, the staff is less concerned with cost and comparability among companies if the Task Force chooses Alternative 2. That is, companies could choose to designate or not designate a contract as NPNS under Alternative 2. However, the staff notes that prospective transition would be less costly than retrospective transition for companies that elect to prospectively designate contracts as NPNS because it would not require revisions to historical financial statements. In addition, the staff is less concerned with consistency between financial statement periods because NPNS can be elected for any qualifying contract after inception.

76. Proponents of View A point out that it would avoid any potential for abuse from using hindsight to select which contracts to retrospectively designate as NPNS. That is, prospective transition prevents a company from “cherry-picking” only certain contracts, such as those that are in a gain (or loss) position, to retrospectively designate as NPNS.

77. Opponents of View A point out that it would not resolve the diversity in practice that exists today.

\textit{View B – The effects of initially adopting the guidance in this Issue as of the effective date should be applied on a retrospective basis.}

78. View B would require application of the guidance in this Issue to all existing and previously settled contracts, as well as to new contracts entered into on or after the effective date. Therefore, preparers would be given the option to retrospectively designate qualifying contracts as NPNS by revising their historical financial statements to eliminate the effects of derivative accounting for those contracts.

79. As discussed above, the staff is less concerned with cost and comparability among companies if the Task Force chooses Alternative 2 because NPNS is elective. However,
companies that elect to designate contracts as NPNS on a retrospective basis would incur costs to revise their historical financial statements to remove the effects of derivative accounting.

80. Proponents of View B point out that it could result in the most consistency between financial statement periods. However, because the NPNS scope exception is elective for any qualifying contract after inception, full consistency can never be assured.

81. Opponents of view B believe that it could provide opportunities for abuse. That is, because NPNS is an election that can be made on a contract-by-contract basis, preparers could use hindsight in evaluating the performance of each derivative and “cherry-pick” only certain contracts for designation as NPNS.

View C – The effects of initially adopting the guidance in this Issue as of the effective date should be applied on a modified retrospective basis.

82. View C would require application of the guidance in this Issue to all contracts existing on the effective date, as well as to new contracts entered into after the effective date through a cumulative effect adjustment. Therefore, preparers would be given the option to retrospectively designate contracts within the scope of this Issue as NPNS through a cumulative-effect adjustment to the opening balance of retained earnings as of the beginning of the year, in the period of adoption.

83. As discussed above, the staff is less concerned with cost and comparability between companies if the Task Force chooses Alternative 2 because the NPNS scope exception is elective. However, the staff notes that modified retrospective transition would be less costly than retrospective transition because it would not require revisions to historical financial statements for companies that elect to retrospectively designate contracts as NPNS.

84. Proponents of View C believe that it could increase comparability among companies because they would be able to retrospectively designate contracts as NPNS on the effective date. That is, a company would not be required to cease marking the contract to market and prospectively account for the carrying value of the derivative at the time of
designation under other applicable GAAP. However, the staff notes that because the NPNS scope exception is elective, full comparability can never be assured.

85. Opponents of view C believe that it could provide opportunities for abuse. That is, because the NPNS scope exception is an election that can be made on a contract-by-contract basis, preparers could use hindsight in evaluating the performance of each derivative and “cherry-pick” only certain contracts for designation as NPNS.

**Staff Recommendation**

86. The staff recommends View A because prospective transition avoids any potential for abuse from using hindsight to select which contracts to retrospectively designate as NPNS. Although View A does not resolve the diversity in practice that exists today, the staff points out that a majority of companies currently designate contracts within the scope of this Issue as NPNS. Furthermore, prospective transition is consistent with the transition framework established by DIG K5 for contracts that were previously accounted for as derivatives but are not accounted for as derivatives under newly issued implementation guidance.

87. The staff does not recommend that companies be given the option of applying retrospective transition because of the potential for abuse discussed above.

**Transition Disclosures**

88. Subtopic 250-10, Accounting Changes and Error Corrections – Overall, requires the following disclosures in the period in which a change in accounting principle is made:

   **250-10-50-1** An entity shall disclose all of the following in the fiscal period in which a change in accounting principle is made:

   a. The nature of and reason for the change in accounting principle, including an explanation of why the newly adopted accounting principle is preferable.

   b. The method of applying the change, including all of the following:

      1. A description of the prior-period information that has been retrospectively adjusted, if any.
2. The effect of the change on income from continuing operations, net income (or other appropriate captions of changes in the applicable net assets or performance indicator), any other affected financial statement line item, and any affected per-share amounts for the current period and any prior periods retrospectively adjusted. Presentation of the effect on financial statement subtotals and totals other than income from continuing operations and net income (or other appropriate captions of changes in the applicable net assets or performance indicator) is not required.

3. The cumulative effect of the change on retained earnings or other components of equity or net assets in the statement of financial position as of the beginning of the earliest period presented.

4. If retrospective application to all prior periods is impracticable, disclosure of the reasons therefore, and a description of the alternative method used to report the change (see paragraphs 250-10-45-5 through 45-7).

c. If indirect effects of a change in accounting principle are recognized both of the following shall be disclosed:

1. A description of the indirect effects of a change in accounting principle, including the amounts that have been recognized in the current period, and the related per-share amounts, if applicable.

2. Unless impracticable, the amount of the total recognized indirect effects of the accounting change and the related per-share amounts, if applicable, that are attributable to each prior period presented. Compliance with this disclosure requirement is practicable unless an entity cannot comply with it after making every reasonable effort to do so.

Financial statements of subsequent periods need not repeat the disclosures required by this paragraph. If a change in accounting principle has no material effect in the period of change but is reasonably certain to have a material effect in later periods, the disclosures required by (a) shall be provided whenever the financial statements of the period of change are presented.

250-10-50-2 An entity that issues interim financial statements shall provide the required disclosures in the financial statements of both the interim period of the change and the annual period of the change.

250-10-50-3 In the fiscal year in which a new accounting principle is adopted, financial information reported for interim periods after the date of adoption shall disclose the effect of the change on income from continuing operations, net income (or other appropriate captions of changes in the applicable net assets or performance
indicator), and related per-share amounts, if applicable, for those post-change interim periods.

### Questions 5 and 6 for the Task Force

<table>
<thead>
<tr>
<th>Question</th>
<th>Answer</th>
</tr>
</thead>
<tbody>
<tr>
<td>5.</td>
<td>Does the Task Force believe that transition disclosures should follow the guidance in paragraphs 250-10-50-1 through 50-3?</td>
</tr>
<tr>
<td>6.</td>
<td>Are there any additional transition disclosures that the Task Force believes are necessary?</td>
</tr>
</tbody>
</table>

### Staff Analysis and Recommendation

89. If the Task Force chooses Alternative 1, the staff recommends that the transition disclosures follow the guidance in paragraphs 250-10-50-1 through 50-3. Certain of those disclosure requirements may not be applicable, depending upon the decisions reached by the Task Force with respect to transition. For example, paragraph 250-10-50-1(b)(1) would not be applicable if the Task Force decides transition should be applied on a prospective basis or modified retrospective basis. However, the staff does not believe that preparers will have difficulty identifying the inapplicable disclosures.

90. In addition, paragraphs 250-10-50-1 through 50-3 require an entity to disclose the nature and reason for an accounting change, the method of applying the change, and any indirect effects of the accounting change. The staff believes that all of those disclosure requirements would sufficiently explain the change in accounting principle; therefore, the staff does not recommend requiring any transition disclosures beyond the existing disclosure requirements in Topic 250.

91. If the Task Force chooses Alternative 2, the staff recommends that the transition disclosures follow only the guidance in paragraphs 250-10-50-1 through 50-2. The staff does not believe that companies should be required to disclose the change in fair value of contracts designated as NPNS as a result of this Issue in the interim and annual financial statements in the fiscal year of adoption. Such a disclosure would result in increased costs to preparers to determine the fair value of contracts for disclosure purposes that are not recognized in the financial statements. Based on our outreach, users do not believe that mark-to-market information for routine revenue and cost of sales transactions is
decision-useful. Furthermore, there currently is no similar disclosure required when companies designate contracts after the inception date under GAAP.
Appendix 15-AA: Simplified diagram of an ISO

- ISO
- Nodes
- Location B "Hub"
- End-Use Customers
- Location A
- Transmission Lines (operated by ISO)
- Distribution Lines (owned and operated by PowerCo (the utility or LSE))
Appendix 15-AB: General NPNS criteria

>>> Normal Purchases and Normal Sales

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.

815-10-15-23 The assessment of whether a contract qualifies for the normal purchases and normal sales scope exception (including whether the underlying of a price adjustment within the contract is not clearly and closely related to the asset being sold or purchased) shall be performed only at the inception of the contract.

815-10-15-24 The normal purchases and normal sales scope exception sometimes will result in different parties to a contract reaching different conclusions about whether the contract is required to be accounted for as a derivative instrument. For example, the contract may be for ordinary sales by one party but not for ordinary purchases by the counterparty.

815-10-15-25 Following are discussions of four important elements needed to qualify for the normal purchases and normal sales scope exception:

   a. Normal terms (including normal quantity)
   b. Clearly and closely related underlying
   c. Probable physical settlement
   d. Documentation.

815-10-15-26 Also discussed is guidance that should be considered in determining whether each of the following specific types of contracts qualifies for the normal purchases and normal sales scope exception:

   a. Freestanding option contracts
   b. Forward (non-option-based) contracts
   c. Forward contracts that contain optionality features
   d. Power purchase or sale agreements.

>>> Normal Terms (Including Normal Quantity)

815-10-15-27 To qualify for the scope exception, a contract’s terms must be consistent with the terms of an entity’s normal purchases or normal sales, that is, the quantity purchased or sold
must be reasonable in relation to the entity’s business needs. Determining whether or not the terms are consistent requires judgment.

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.

815-10-15-29 Further, each of the following types of evidence should help in identifying contracts that qualify as normal purchases or normal sales:

a. Past trends
b. Expected future demand
c. Other contracts for delivery of similar items
d. An entity's and industry's customs for acquiring and storing the related commodities
e. An entity's operating locations.

For guidance on normal purchases and normal sales as hedged items, see paragraph 815-20-25-7.

Clearly and Closely Related Underlying

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) or that are denominated in a foreign currency that meets none of the criteria in paragraph 815-15-15-10(b) shall not be considered normal purchases and normal sales.

815-10-15-31 The phrase not clearly and closely related in the preceding paragraph 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. The guidance in this discussion of normal purchases and normal sales does not affect the use of the phrase not clearly and closely related in paragraphs other than the preceding paragraph. For purposes of determining whether a contract qualifies for the normal purchases and normal sales scope exception, the application of the phrase not clearly and closely related to the asset being sold or purchased shall involve an analysis of both qualitative and quantitative considerations. The analysis is specific to the contract being considered for the normal purchases and normal
sales scope exception and may include identification of the components of the asset being sold or purchased.

815-10-15-32 The underlying in a price adjustment incorporated into a contract that otherwise satisfies the requirements for the normal purchases and normal sales scope exception shall be considered to be not clearly and closely related to the asset being sold or purchased in any of the following circumstances:

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 815-15-10(b) for that reporting entity.

815-10-15-33 For example, in the case in which the price adjustment focuses on the changes in the fair value of the asset being purchased or sold, if the terms of the price adjustment are expected, at the inception of the contract, to affect the purchase or sales price in a manner comparable to the outcome that would be obtained if, at each delivery date, the parties were to reprice the contract amount under the then-existing conditions for the asset being delivered on that date, the price adjustment’s underlying is considered to be clearly and closely related to the asset being sold or purchased and the price adjustment would not be an impediment to the contract qualifying for the normal purchases and normal sales scope exception.

815-10-15-34 If the underlying in a price adjustment incorporated into a purchase or sales contract is not an impediment to qualifying for the normal purchases and normal sales scope exception because it is considered to be clearly and closely related to the asset being sold or purchased, the contract must meet the other requirements in this Subsection to qualify for the normal purchases and normal sales scope exception.

>>> Probable Physical Settlement

815-10-15-35 For a contract that meets the net settlement provisions of paragraphs 815-10-15-100 through 15-109 and the market mechanism provisions of paragraphs 815-10-15-110 through 15-118 to qualify for the 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.

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 gains or losses periodically because those settlements are net
settlements. Paragraph 815-20-25-22 explains how an entity may designate such a contract as a
hedged item in an all-in-one hedge if all related criteria are met.

>> > >  Documentation

815-10-15-37 For contracts that qualify for the normal purchases and normal sales exception
under any provision of paragraphs 815-10-15-22 through 15-51, 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.

815-10-15-38 The documentation requirements can be applied either to groups of similarly
designated contracts or to each individual contract. Failure to comply with the documentation
requirements precludes application of the normal purchases and normal sales scope exception to
contracts that would otherwise qualify for that scope exception.

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.

>> > >  Application to Freestanding Option Contracts

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.

>> > >  Application to Forward (Non-Option-Based) Contracts

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. Contracts that are subject to unplanned netting
(referred to as a book-out in the electric utility industry) do not qualify for this scope exception except as specified in paragraph 815-10-15-46. Net settlement (as described in paragraphs 815-10-15-100 through 15-109 and 815-10-15-110 through 15-118) 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. 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.

>> Application to Forward Contracts that Contain Optionality Features

815-10-15-42 Forward contracts that contain optionality features that do not modify the quantity of the asset to be delivered under the contract are eligible to qualify for the normal purchases and normal sales scope exception. 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. For forward contracts that contain optionality features to qualify for the normal purchases and normal sales scope exception, the criteria discussed in the preceding paragraph must be met.

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. Example 10 (see paragraph 815-10-55-121) illustrates this guidance.

815-10-15-44 The inclusion of a purchased option that would, if exercised, require delivery of the related asset at an established price under the contract within a single contract that meets the definition of a derivative instrument disqualifies the entire contract from being eligible to qualify for the normal purchases and normal sales scope exception in this Subsection except as provided in the following paragraph through paragraph 815-10-15-51 with respect to certain power purchase or sales agreements.
Appendix 15-AC: NPNS criteria for capacity contracts

>> Application to Power Purchase or Sale Agreements

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:

a. For both parties to the contract, both of the following criteria are met:

1. The terms of the contract require physical delivery of electricity. That is, the contract does not permit net settlement, as described in paragraphs 815-10-15-100 through 15-109. For an option contract, physical delivery is required if the option contract is exercised.

2. The power purchase or sales agreement is a capacity contract. Differentiating between a capacity contract and a traditional option contract (that is, a financial option on electricity) is a matter of judgment that depends on the facts and circumstances. For power purchase or sale agreements that contain option features, the characteristics of an option contract that is a capacity contract and a traditional option contract, which are set forth in paragraph 815-10-55-31 shall be considered in that evaluation; however, other characteristics not listed in that paragraph may also be relevant to that evaluation.

b. For the seller of electricity: The electricity that would be deliverable under the contract involves quantities that are expected to be sold by the reporting entity in the normal course of business.

c. For the buyer of electricity, all of the following criteria are met:

1. 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.

2. 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.

3. 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.
815-10-15-46 Power purchase or sales agreements that meet only the applicable criteria in paragraph 815-10-15-45 qualify for the normal purchases and normal sales scope exception even if they are subject to being booked out or are scheduled to be booked out.

815-10-15-47 Forward contracts for the purchase or sale of electricity that do not meet those applicable criteria as well as other forward contracts are nevertheless eligible to qualify for the normal purchases and normal sales scope exception by meeting the criteria in this Subsection (other than paragraph 815-10-15-45), unless those contracts are subject to unplanned netting (that is, subject to possibly being booked out).

815-10-15-48 Because electricity cannot be readily stored in significant quantities and the entity engaged in selling electricity is obligated to maintain sufficient capacity to meet the electricity needs of its customer base, an option contract for the purchase of electricity that meets the criteria in paragraph 815-10-15-45 qualifies for the normal purchases and normal sales scope exception in that paragraph.

815-10-15-49 This guidance does not affect the accounting for requirements contracts that would not be required to be accounted for under the guidance in this Subtopic pursuant to paragraphs 815-10-55-5 through 55-7.

815-10-15-50 Contracts that qualify for the normal purchases and normal sales scope exception based on this guidance do not require compliance with any additional guidance in paragraphs 815-10-15-22 through 15-44. However, contracts that have a price based on an underlying that is not clearly and closely related to the electricity being sold or purchased or that are denominated in a foreign currency that meets none of the criteria in paragraph 815-15-15-10(b) shall not be considered normal purchases and normal sales.

815-10-15-51 This guidance shall not be applied by analogy to the accounting for other types of contracts not meeting the stated criteria.
Appendix 15-AD: Mark-up of the proposed guidance to reflect Alternative 1

>>> > Probable Physical Settlement

815-10-15-35 For a contract that meets the net settlement provisions of paragraphs 815-10-15-100 through 15-109 and the market mechanism provisions of paragraphs 815-10-15-110 through 15-118 to qualify for the 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.

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 gains or losses periodically because those settlements are net settlements. Paragraph 815-20-25-22 explains how an entity may designate such a contract as a hedged item in an all-in-one hedge if all related criteria are met.

815-10-15-36A Certain contracts for the physical delivery of electricity on a forward basis to a location within an electricity grid operated by an independent system operator result in one of the contracting parties incurring charges (or credits) for the subsequent transmission of that electricity based in part on locational marginal pricing differences payable to (or receivable from) the independent system operator. For example, this is the case when the delivery location under the forward contract (for example, a hub location) is not the point of ultimate consumption/delivery of the electricity (for example, a customer load zone). Delivery to the point of ultimate consumption/delivery is facilitated in real-time by the independent system operator. These contracts do not qualify for the normal purchases and normal sales scope exception for the contracting party that incurs the charges (or credits) payable to (or receivable from) the independent system operator because the use of locational marginal pricing to determine the transmission charge (or credit) constitutes net settlement of the forward contract.

>>> > Application to Power Purchase or Sale Agreements

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:

a. For both parties to the contract, both of the following criteria are met:

1. The terms of the contract require physical delivery of electricity. That is, the contract does not permit net settlement, as described in paragraphs 815-10-15-100 through 15-109. For an option contract, physical delivery is required if the option contract is exercised. Certain contracts for the physical delivery of electricity on a forward basis to a location within an electricity grid operated by an independent system operator result in one of the contracting parties incurring charges (or credits) for the subsequent transmission of that electricity based in part on locational marginal pricing differences payable to (or receivable from) the independent system operator. For example, this is the case when the
delivery location under the forward contract (for example, a hub location) is not the point of ultimate consumption/delivery of the electricity (or example, a customer load zone). Delivery to the point of ultimate consumption/delivery is facilitated in real-time by the independent system operator. These contracts do not qualify for the normal purchases and normal sales scope exception for the contracting party that incurs the charges (or credits) payable to (or receivable from) the independent system operator because the use of locational marginal pricing to determine the transmission charge (or credit) constitutes net settlement of the forward contract.

2. The power purchase or sales agreement is a capacity contract. Differentiating between a capacity contract and a traditional option contract (that is, a financial option on electricity) is a matter of judgment that depends on the facts and circumstances. For power purchase or sale agreements that contain option features, the characteristics of an option contract that is a capacity contract and a traditional option contract, which are set forth in paragraph 815-10-55-31 shall be considered in that evaluation; however, other characteristics not listed in that paragraph may also be relevant to that evaluation.
Appendix 15-AE: Mark-up of the proposed guidance to reflect Alternative 2

>>> Probable Physical Settlement

15-35 For a contract that meets the net settlement provisions of paragraphs 815-10-15-100 through 15-109 and the market mechanism provisions of paragraphs 815-10-15-110 through 15-118 to qualify for the 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.

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 gains or losses periodically because those settlements are net settlements. Paragraph 815-20-25-22 explains how an entity may designate such a contract as a hedged item in an all-in-one hedge if all related criteria are met.

815-10-15-36A Certain contracts for the physical delivery of electricity on a forward basis to a location within an electricity grid operated by an independent system operator result in one of the contracting parties incurring charges (or credits) for the subsequent transmission of that electricity based in part on locational marginal pricing differences payable to (or receivable from) the independent system operator. For example, this is the case when the delivery location under the forward contract (or example, a hub location) is not the point of ultimate consumption/delivery of the electricity (for example, a customer load zone). Delivery to the point of ultimate consumption/delivery is facilitated in real-time by the independent system operator. The forward contract and the real-time transmission services do not constitute a series of sequential contracts intended to accomplish ultimate acquisition or sale of a commodity, and the use of locational marginal pricing to determine the transmission charge (or credit) does not constitute net settlement even in situations in which legal title to the associated electricity is conveyed to the independent system operator during transmission.

>>> Application to Power Purchase or Sale Agreements

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:

a. For both parties to the contract, both of the following criteria are met:

   1. The terms of the contract require physical delivery of electricity. That is, the contract does not permit net settlement, as described in paragraphs 815-10-15-100 through 15-109. For an option contract, physical delivery is required if the option contract is exercised. Certain contracts for the physical delivery of electricity on a forward basis to a location within an electricity grid operated by an independent system operator result in one of the contracting parties incurring charges (or credits) for the subsequent transmission of that electricity based in part on locational marginal pricing differences payable to (or
receivable from) the independent system operator. For example, this is the case when the delivery location under the forward contract (for example, a hub location) is not the point of ultimate consumption/delivery of the electricity (or example, a customer load zone). Delivery to the point of ultimate consumption/delivery is facilitated real-time by the independent system operator. The use of locational marginal pricing to determine the transmission charge (or credit) does not constitute net settlement even in situations in which legal title to the associated electricity is conveyed to the independent system operator during transmission.

2. The power purchase or sales agreement is a capacity contract. Differentiating between a capacity contract and a traditional option contract (that is, a financial option on electricity) is a matter of judgment that depends on the facts and circumstances. For power purchase or sale agreements that contain option features, the characteristics of an option contract that is a capacity contract and a traditional option contract, which are set forth in paragraph 815-10-55-31 shall be considered in that evaluation; however, other characteristics not listed in that paragraph may also be relevant to that evaluation.