The Edison Electric Institute (EEI) respectfully submits our comments on the Financial Accounting Standards Board (FASB) Proposed Accounting Standards Update—Leases (Topic 840) (the ED). EEI is the association of United States shareholder-owned electric companies. Our members provide service to 95 percent of the ultimate customers in the shareholder-owned segment of the industry, and represent approximately 70 percent of the United States electric power industry.

EEI appreciates that the FASB and International Accounting Standards Board (IASB) are seeking to develop a converged standard on leasing. Leasing arrangements are widely used in our industry, and there are many provisions included in the ED that will significantly affect our member companies. We have limited our responses to questions for which we have concerns, request clarification, make recommendations, or wish to convey our support. In addition, included in Appendix A to this letter, we address a number of concerns we have as to applying the lease accounting guidance to power purchase agreements and other commodity supply agreements, as well as certain areas of current diversity in practice in this area.

Summary

Highlights of our comments are summarized as follows:

- We seek clarification on application of the ED to power purchase agreements and similar output-based arrangements linked to physical assets, particularly with regard to "right to use" pricing criteria, the meaning of "output", and allocation of contractual consideration to identified lease and non-lease elements.
• We believe the ED’s guidance on determining whether a lessor retains exposure to significant risks or benefits associated with underlying leased assets should be expanded to contemplate the returns generated by operating the asset.

• We believe that lessees should have the option not to record lease assets and liabilities associated with short-term leases similar to the election afforded lessors.

• We disagree with the requirement to determine the lease term in a manner other than by reference to the contractually stipulated term as we believe no further obligation has been incurred and that the value of the option is already reflected at fair value at inception of the lease in the contractual lease payments.

• We believe flexibility should exist to utilize alternative methods of estimating contingent rentals and expected payments under term option penalties and residual value guarantees when such methods are supportable and indicative of management’s best estimates.

• We seek clarification on what would constitute a reasonable analysis or framework necessary to assess changes in facts or circumstances when determining whether they would indicate a significant change in lease assets and liabilities.

• We recommend that the Boards reconsider the income statement presentation provisions in the ED and allow preparers to continue to record lease expenses within operating income when the nature of such costs represent costs of goods sold.

• We disagree with the proposed requirement to disclose quantitative reconciliations of beginning and ending lease asset and liability balances.

• We seek relief on the proposed retrospective application with regard to leases that no longer exist at the current period upon adoption, as well as interaction of the ED’s transition provisions with the grandfathering provisions under Emerging Issues Task Force Issue No. 01-08, Determining Whether an Arrangement Contains a Lease (EITF 01-8).

• We seek guidance and/or propose our views on the following additional topics:
  o Retention of existing lease accounting guidance for regulated enterprises
  o Recognition of an onerous contract between lease inception and commencement
  o Lessor’s accounting model application when assessing residual assets for impairment
Our Primary Concern – Application of Lease Guidance to Power Purchase Agreements

The primary concern for our members relates to the application of the ED to power purchase agreements (PPAs). There has been considerable diversity in interpretation of the existing guidance originally provided in paragraph 12 of EITF 01-08 (essentially carried over to paragraph B4 of the ED), which is used to distinguish between those contracts that are executory supply agreements and those that contain leases.

Because of the significant change in accounting for agreements that contain leases being proposed in the ED, it is imperative that the differences in interpretation be resolved. In addition, it is critical that the criteria in that guidance are effective in appropriately distinguishing between executory contracts and lease contracts. If the criteria do not result in an appropriate distinction, or if the criteria are interpreted differently in practice, the application of the ED will produce significantly divergent accounting results within all of the primary financial statements (including related impacts on key performance metrics) for economically similar contracts. For example, from a lessee’s perspective, the following differences in financial statement recognition and presentation will result for payments associated with the lease element of the agreement:

<table>
<thead>
<tr>
<th></th>
<th>Executory</th>
<th>Lease</th>
</tr>
</thead>
<tbody>
<tr>
<td>Right-of-use asset</td>
<td>N/A</td>
<td>recorded on balance sheet</td>
</tr>
<tr>
<td>Lease obligation</td>
<td>N/A</td>
<td>recorded on balance sheet</td>
</tr>
<tr>
<td>Gross margin</td>
<td>included as fuel purchase</td>
<td>excluded</td>
</tr>
<tr>
<td>Amortization expense</td>
<td>N/A</td>
<td>included</td>
</tr>
<tr>
<td>Interest expense</td>
<td>N/A</td>
<td>included using interest method</td>
</tr>
<tr>
<td>Timing of expense</td>
<td>Straight-line</td>
<td>Front-end loaded financing</td>
</tr>
<tr>
<td>Cash flow statement</td>
<td>operating</td>
<td></td>
</tr>
</tbody>
</table>

Most PPAs reflect the purchase of a product, not the right to use an asset. We recommend that the criteria for identification of agreements that contain in-substance leases be amended to be more principles-based and to more effectively make the distinction between executory contracts and leases. If the Boards decide not to amend
the guidance, it is crucial that the Boards' intentions be clarified so that interpretational differences can be resolved. We direct your attention to Appendix A to this letter which addresses our concerns and recommendations for this and other issues related to PPAs in more detail.

Responses to Questions in the ED

Question 2(a): Do you agree that a lessor should apply (i) the performance obligation approach if the lessor retains exposure to significant risks or benefits associated with the underlying asset during or after the expected lease term, and (2) the derecognition approach otherwise? Why or why not? If not, what alternative approach would you propose and why?

Overall, we agree with the approach for determining when a lessor should apply the performance obligation approach or the derecognition approach. However, we believe that the criteria for determining whether a lessor should apply the performance obligation approach should be expanded to include scenarios where the lessor plans to generate significant returns by operating the asset. Paragraph 28 of the ED notes that the performance obligation approach is appropriate when the "lessor retains exposure to significant risks or benefits associated with the underlying asset either:

(a) during the expected term of the lease; or
(b) after the expected term of the lease by having the expectation or ability to generate significant returns by re-leasing or reselling the underlying asset."

We believe the second criterion should be expanded to include "re-leasing, reselling or operating the underlying asset." That approach is consistent with paragraph BC27, which states the "performance obligation approach is likely to be appropriate in situations in which the entity's business is primarily to generate a return from active management of the underlying assets to multiple lessees during their life or from use or sale of those assets at the end of their lease." (emphasis added)

Question 3: Do you agree that a lessee or a lessor should account for short-term leases in this way? Why or why not? If not, what alternative approach would you propose and why?
EEI appreciates the Boards’ effort to simplify the accounting for short-term leases. We note that paragraph 65 of the ED allows lessors the option of not recording lease-related assets and liabilities, nor derecognizing any portion of the leased asset. We believe that a similar option is appropriate for lessees and that the accounting should be symmetrical. That is, we do not believe requiring lessees to capitalize a right-of-use asset and related obligation for short-term leases would increase the usefulness of the financial statements for the investor.

Even when a short-term lease crosses reporting dates, the incremental information provided does not justify the cost required to compile and track the information. For many companies, accounting for leases is decentralized and leases are manually accounted for using electronic spreadsheets. We believe that the cost of tracking and reporting information regarding short-term leases outweighs the benefits to the financial statement user.

As an alternative approach, we suggest that at the date of lease inception a lessee have the option to elect, on a lease-by-lease basis, not to recognize assets or liabilities arising from a short-term lease in the balance sheet similar to proposed lessor accounting for short-term leases. Finally, consistent with our response to question 8 below, we believe that only the base (contractually obligated) lease term should be included in the determination of whether a lease is “short term” or “long term”.

**Question 4:**
(a) Do you agree that a lease is defined appropriately? Why or why not? If not, what alternative definition would you propose and why?
(b) Intentionally omitted
(c) Do you think that the guidance in paragraphs B1–B4 for distinguishing leases from service contracts is sufficient? Why or why not? If not, what additional guidance do you think is necessary and why?

We believe that the criteria used to determine whether a contract contains a lease, particularly as it relates to the definition and pricing of outputs, needs to be revised to appropriately distinguish between a lease and an executory contract. As noted above, this is particularly important in our industry where we have long-term PPAs. Our suggestions for improvements in the definitions are included in Appendix A.
Further, we believe that for a contract to contain a lease, fulfillment of the contract must depend on providing a specified asset. Paragraph B2 of the ED describes that the asset under contract will be considered to be implicitly ‘specified’ if “a lessor can substitute another asset for the underlying asset but rarely does.” We believe this criterion is inconsistent with the concept used to determine whether an arrangement contains a lease. A key concept in making this determination is that the lessee either physically or contractually controls the asset identified by the contract. The fact that a lessor has the option to satisfy the contract using other assets, but generally chooses to use a particular asset indicates that control remains with the lessor.

Also, this makes the assumption that the lessee would be able to determine what assets will be used to satisfy the contract. This information is generally not available to the purchasing party at the inception of an agreement, especially in cases when no asset is identified in the contract. This position is also explicitly counter to the conclusions reached in Paragraph B9 of EITF 01-8, which states that; if “...no property, plant, or equipment is explicitly specified in the contract and it is economically feasible for the seller to perform its obligation independent of the operation of a particular asset, there would be no implicit specification of the property, plant, or equipment and such a contract would not contain a lease.”

**Question 6:** Do you agree with either approach to accounting for leases that contain service and lease components? Why or why not? If not, how would you account for contracts that contain both service and lease components and why?

The ED proposes that lessees and lessors should apply the guidance in Proposed Accounting Standards Update, *Revenue Recognition* (Topic 605): *Revenue from Contracts with Customers* (Revenue Recognition ED), to distinct service components of a contract that contains service components and lease components. The ED does not provide guidance for separating other non-service elements of contracts that are determined to contain leases. Diversity exists in current practice with regard to the appropriate method of allocating consideration between lease and non-lease elements within a contract, and we believe that further clarification is needed with regard to applying the proposed approach within the ED. See further detailed discussion and examples within Appendix A.

**Question 8:** Do you agree that a lessee or a lessor should determine the lease term as the longest possible term that is more likely than not to occur taking into account the effect of any options to extend or terminate the lease? Why or why not? If not, how do you propose that a lessee or a lessor should determine the lease term and why?
We do not agree with this proposal. EEI believes that only the lease term to which the parties are contractually obligated should be reflected in the rights and obligations recorded in connection with a lease agreement. From the lessee’s standpoint, the liability for lease payments should be based on the contractually obligated (base) lease term, excluding payments associated with possible renewal terms. The lessee is not yet obligated to make payments beyond the base lease term and no liability for those payments has been incurred. Additionally, the right to use the asset during the renewal period only comes into existence when and if the extension is exercised. Therefore, we strongly believe that it simply would be incorrect to record a liability for payments when no obligation exists or an asset where a right to use has not been established. Similarly, from the lessor’s standpoint, there is no right to receive future rental payments until the term extending option is exercised by the lessee.

Further, the value of the option to extend the lease is already embedded in the payments for the base lease term. Said another way, any “premium” paid to acquire the term extending option must be included in the base lease term payments, or the lessor would never be paid for the value of such option. Given that the right to extend a lease has value to both the lessor and the lessee and that unrelated parties do not unilaterally forego value in an arms-length transaction, the value of the option to extend the lease term is included in the right-of-use asset as computed based on lease payments during the base lease term, even though it is not separately identified.

**Question 9:** Do you agree that contingent rentals and expected payments under term option penalties and residual value guarantees that are specified in the lease should be included in the measurement of assets and liabilities arising from a lease using an expected outcome technique? Why or why not? If not, how do you propose that a lessee or a lessor should account for contingent rentals and expected payments under term option penalties and residual value guarantees and why?

We believe that the final standard should allow for more flexibility in measuring contingent rentals. We recommend that companies be allowed to utilize existing valuation methods for measuring contingent rentals and other expected payments under term option penalties and residual value guarantees.

In many cases, companies have developed sophisticated models and techniques to value contractual uncertainties on a “best estimate” basis in order to support management decisions. As an example, for PPAs tied to plant production that are deemed to contain a lease under paragraph B4 of the ED, forecasted production levels often represent the
primary contingency associated with the portion of contractual consideration allocable to
the lease element in the arrangement (see separate discussion on identifying lease and
non-lease obligations and related allocation of contractual consideration within
Appendix A).

In practice, many energy companies have developed sophisticated, in-house models to
predict forecasted production levels based on planned and unplanned plant outages,
historical production data, and anticipated shifts in infrastructure supply/demand market
fundamentals. In the case of renewable projects (wind, solar or landfill gas for example),
those models may also incorporate mathematical simulation or statistical means to
anticipate the effect of seasonal weather patterns, locational characteristics, and a
number of other factors if warranted. In many cases, these models are already subject to
rigorous internal control processes (for operational and/or financial reporting
requirements) to establish the propriety and ongoing monitoring of key assumptions and
methodologies.

We believe such an example illustrates that an entity should have the flexibility to use
alternative approaches when it can support its methodologies and key assumptions
resulting in “best estimates” of contingencies that ultimately affect recorded lease
payments. We perceive that in certain situations, the probability-weighted approach
described within the ED could result in less, not more, reliable and accurate information.

**Question 10:** Do you agree that lessees and lessors should remeasure assets and
liabilities arising under a lease when changes in facts or circumstances indicate that
there is a significant change in the liability to make lease payments or in the right to
receive lease payments arising from changes in the lease term or contingent payments
(including expected payments under term option penalties and residual value
guarantees) since the previous reporting period? Why or why not? If not, what other
basis would you propose for reassessment and why?

We agree in principle with the provisions of paragraphs 17, 39, and 56 that factors
driving contingent payments should be reassessed if changes in facts or circumstances
indicate a potentially significant change in the measurement of related lease assets or
liabilities, although we do not agree that such an evaluation is necessary regarding the
lease term (see response to question 8 above regarding assessment of lease term). We
also appreciate the Boards’ attempt to alleviate the administrative burden of explicitly
requiring periodic reassessment of such factors except in cases where facts or
circumstances warrant, as indicated in paragraphs BC133 and BC134.
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However, we believe it is likely there will be some level of change in facts or circumstances that occur within each reporting period with respect to some or all of these factors. Although we understand from recent lease roundtable events that this is a potential concern across multiple industries, the PPA example in response to Question 9 above can be further used to illustrate our concern that contingent payments fluctuate period to period in large part based on changes in plant production profiles, weather, and other economic factors.

As such, we have some concern that in the absence of clarification, the steps practically required to assess the significance of changes in facts or circumstances could likely result in the same level of effort expended as if an entity were explicitly required to reassess all contingency factors and remeasure related lease assets or liabilities in order to determine the significance of such changes. Said differently, given the focus on supporting judgments and estimates within the U.S. regulatory environment for both issuers and auditors, we foresee difficulty supporting conclusions regarding the significance of such changes without going through the actual exercise of reassessing assumptions each reporting period and computing the impact on measurement of the related lease assets and liabilities.

Therefore, we propose that a “trigger event” approach of some form be followed to determine whether changes in the facts and circumstances surrounding contingent payments are significant enough to warrant reassessment of the underlying assumptions influencing measurement (i.e., unexpected asset outages/availability, unusual changes in economic/environmental factors such as demand destruction, changes in an entity’s business model or intended use, etc.). We believe this is consistent with the less onerous approach indicated in the basis for conclusions to the ED and is more likely to result in application of the provisions of the ED in the way they appear to be intended.

Question 13: Do you think that lessees and lessors should present lease income and lease expense separately from other income and expense in the income statement (paragraphs 26, 44, 61, 62, BC146, BC151, BC152, BC157 and BC158)? Why or why not? If not, do you think that a lessee should disclose that information in the notes instead? Why or why not?
Our members execute a number of different contracts for the purchase of fuel and energy from specific plants that may qualify as (or contain) leases under the existing and proposed guidance (see separate concerns regarding scope and lease element identification in Appendix A). Such contracts are entered into for the purpose of purchasing power to satisfy load serving requirements, satisfying governmental requirements for purchases of renewable energy, and other contractual sales obligations and fuel requirements for owned generation plants. The costs incurred under those contracts are an integral part of the key operations of our members. Even though some contracts meet the definition of a lease, the expenses associated with these contracts are currently classified as fuel and purchased energy expenses within operating income and are evaluated as part of gross margin within the Management Discussion and Analysis sections of the SEC filings. Further, the cash payments are presented as operating activities on the statement of cash flows. In this way, the expenses are presented within the same financial statement captions as the costs of purchases under otherwise identical contracts that do not meet the definition of a lease.

For such arrangements that meet the definition of (or contain) a lease, the proposed guidance will require preparers to present all related rental expenses as amortization and interest expense on the income statement and as financing activities within the statement of cash flows. Depending on how one identifies and measures the appropriate lease and non-lease elements of such an arrangement as discussed in Appendix A, the new presentation could result in a material portion of what has otherwise historically been characterized as fuel and purchased energy costs being recorded outside of gross margin, notwithstanding that the primary economic intent of the arrangement is for the purchase goods (cost of sales) associated with revenue generation. We recommend that the Boards reconsider the income statement presentation provisions in the ED and allow preparers to continue to record lease expenses within operating income when the nature of such costs represent costs of goods sold. We believe that presentation would provide financial statements that are more representationally faithful by affording similar treatment for such costs even though they may be executed under contracts that fall into different classifications.

This issue is directly related to our concerns around the application of the ED to PPAs discussed separately at Appendix A, which will be more prevalent if the criteria for identification of agreements that contain in-substance leases are not amended to be more principles-based and to more effectively make the distinction between executory contracts and leases. With the existing distinction between operating and capital leases, executory contracts and PPAs that meet the criteria for being considered leases are
classified as operating leases and receive treatment similar to non-lease contracts on the income statement. Once this distinction is removed, certain expenses that have historically been presented as costs of goods sold will be presented as interest and amortization expense. This will result in what we believe to be a misstatement of gross margin and operating income. It is critical that the Boards revisit the criteria for identifying agreements that contain in-substance leases before a final standard is issued.

Question 15: Do you agree that lessees and lessors should disclose quantitative and qualitative information that:
   a) identifies and explains the amounts recognized in the financial statements arising from leases; and
   b) describes how leases may affect the amount, timing and uncertainty of the entity's future cash flows?
Why or why not? If not, how would you amend the objectives and why?

We agree with substantially all of the disclosure requirements identified in paragraphs 70-86 of the ED and believe these requirements will provide financial statement users sufficient information to understand the impact of leasing activities on an entity and the amount, timing and uncertainty of the entity’s future cash flows. However, we do not believe the proposed requirement to reconcile opening and closing balances, disaggregated by class of underlying asset as proposed in paragraphs 77 and 80, is necessary to accomplish those objectives.

We believe that a reconciliation of the opening and closing balances provides little additional information that is useful in assessing the amount, timing and uncertainty of the entity’s future cash flows, but it substantially increases the complexity of the footnotes to the financial statements. The ED currently requires separate disclosure of right-of-use assets and liabilities on the face of the statement of financial position. Further, cash flows associated with these assets and liabilities would be separately disclosed in the statement of cash flow. We believe these presentation requirements, coupled with the proposed qualitative disclosure requirements, would provide financial statement users the information necessary to understand the nature and impact of leasing activities on an entity.

Further, we do not believe there is sufficient benefit gained from preparing a reconciliation disaggregated by class of underlying asset relative to the cost and effort that would be required to prepare such a disclosure. Whether an entity is leasing real estate or heavy equipment, the fact remains that the entity is committed to future payments, and the aforementioned presentation requirements sufficiently highlight those commitments. Further, from the perspective of a lessee, we believe very little
information concerning an entity's risk profile could be obtained from presenting disaggregated information.

Finally, from the perspective of a lessee, leasing activities may represent a significant financing activity, but we do not believe the nature of these activities is substantially different from other financing arrangements. Similarly, even material right-to-use assets are not different in nature from, and actually would have to be classified within, property, plant and equipment. Therefore, we believe this aspect of the disclosure requirements for leasing activities should be similar to the current disclosure requirements for financing arrangements and property, plant and equipment, which currently do not require such reconciliations. We believe that presenting reconciliations for leasing activities would give more prominence to these activities relative to an entity's other similar asset use and financing activities, which we believe is unnecessary and unwarranted.

If the FASB were to decide that such reconciliations are required, we encourage the FASB to consider limiting their use to lessors that generate revenue from leasing activities. Although we still believe that the other proposed qualitative and quantitative disclosures, if properly applied, would eliminate the need for such reconciliations, retaining the reconciliation provisions would be more appropriate for lessors that generate revenue from leasing activities rather than lessees, for which these activities substantially represent another form of financing.

**Question 16:**
(a) This exposure draft proposes that lessees and lessors should recognize and measure all outstanding leases as of the date of initial application using a simplified retrospective approach (paragraphs 88-96 and BC186-BC199). Are these proposals appropriate? Why or why not? If not, what transitional requirements do you propose and why?

(b) Do you think full retrospective application of lease accounting requirements should be permitted? Why or why not?

(c) Are there any additional transitional issues the boards need to consider? If yes, which ones and why?

The transition guidance in the ED requires entities to "recognize and measure all outstanding contracts within the scope of this guidance as of the date of initial
application.” The date of initial application is the beginning of the first comparative period presented in the financial statements at the date of adoption. As SEC filings require three years of financial data, this retrospective application will potentially require 8entities to evaluate arrangements that qualify as leases that no longer exist on the date of adoption.

We question the relevance of this prior year information, especially for contracts that no longer exist as of the adoption reporting date. Existing disclosures around leases include information on future minimum lease payments and tenors. Users of financial statements tend to have a more prospective view and investors often request comparisons of current financial information to an entity’s plan as opposed to historical comparisons. Thus, the burden that retrospective application would place on preparers is not, in our view, balanced by the minimal potential benefit to financial statement users. Therefore, we recommend that the Boards allow prospective application of the final standard once issued, or at a minimum exclude lease contracts that no longer exist at the adoption date.

Separately, we note that when companies adopted the consensus in EITF 01-08, now codified in Accounting Standards Codification (ASC or “the Codification”) Section 840-10-15, the transition guidance did not require entities to assess the lease classification of contracts that were executed or acquired prior to May 28, 2003. As a result, our members have a significant number of contracts that have not been assessed under the existing leasing guidance. Unless those contracts were modified and reassessed subsequent to the adoption of EITF 01-8, they continue to be accounted for as executory contracts.

We understand that the Boards did not intend for the ED to change the scope of which contracts are considered leases, but rather had as their objective improvement of the accounting (i.e., recognition, measurement, and disclosure) for those contracts already determined to be leases under the existing guidance. Due to the long-term nature of these agreements, our members will have a number of contracts that will need to be newly assessed if a similar grandfathering clause is not included as part of the transition provisions of the proposed guidance.

We do not believe that requiring the evaluation of contracts entered before May 2003 at this point is cost-justified. Adoption of the new lease accounting guidance as proposed in the ED will be a time-consuming and costly effort by most companies. Providing some relief to retain the existing criteria for scope, such as the continued grandfathering of older contracts, will help companies successfully achieve the “bigger picture” improvements to lease accounting over the long run.
We request that the Boards retain the current scope exception for contracts entered into or acquired before May 2003 so that they would not need to be assessed under the ED. If the transition provisions in the final standard do not include such relief, we request that the Boards consider the time and resources required to identify and assess such contracts when determining the final effective date.

**Question 18:** Do you have any other comments on the proposals?

**Lease Accounting by Regulated Entities**

ASC Subtopic 980-840 relates to lease accounting for rate-regulated entities. The paragraphs in that section originated from FAS 71, *Accounting for the Effects of Certain Types of Regulation*, but are currently included in this Codification cross section of Topic 980 (Regulated Operations) and Topic 840 (Leases). Since the proposed exposure draft is intended to replace all current GAAP related to leasing, we are concerned that this section may be eliminated.

ASC 980-840-45-3 specifies that regulated entities should record expense for a lease equal to the amount allowed for rate-making purposes, rather than the amounts that would otherwise be recorded as amortization and interest expense on a capitalized lease:

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.

We believe that guidance should be retained in Topic 980 when that topic is modified to incorporate the guidance of the final standard on leasing. We believe, as is presently permitted under ASC 980-840-45-3, that the timing of expense recognition for leases should be permitted to be modified to conform with rate treatment. Recording expense for leases in an amount equal to the amount allowed for rate-making purposes and included in revenues reflects the effects of the regulator's actions and the cause-and-
effect relationship between a regulated utility’s costs and revenues, resulting in an appropriate matching of the utility’s revenues and expenses. In addition, including that guidance in the standard will result in consistency between the accounting treatment for leases and other regulated transactions addressed under Topic 980 – Regulated Operations.

Onerous Contracts

Paragraph BC173 of the ED’s Basis for Conclusion indicates that there is no lease recognition between the date of inception and the date of commencement, unless the contract is onerous and refers to paragraph 5(d). There is no paragraph 5(d) in the FASB ED. Paragraph BC35 states that a lessee should apply IAS 37, Provisions, Contingent Liabilities and Contingent Assets between the date of inception and the date of commencement of a lease if the lease meets the definition of an onerous contract in IAS 37. There is, however, no mention of onerous contracts in the body of the ED that will become the authoritative guidance for accounting for leases. Please clarify if the Board intends for there to be recognition of onerous contracts between the date of inception and the date of commencement under U.S. GAAP and, if so, how an onerous contract would be defined.

Impairment of Residual Asset

Paragraph 59 of the ED indicates that a lessor shall apply either Topic 350 or Topic 360 at each reporting date to determine whether the residual asset is impaired. It is unclear whether the selection of guidance to follow for evaluating the residual asset for impairment is a choice to be made by the lessor. If the Board did not intend for this to be choice, EEI believes Topic 360 provides the most relevant guidance because the residual asset represents the rights retained by the lessor in the leased property, plant and equipment.

Further, EEI does not see the benefit of performing an impairment assessment on the residual asset at each period. As with other property, plant and equipment, we believe the residual asset should be evaluated for impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable.
Conclusion

We appreciate your consideration of this topic and our comments. The proposed changes to the accounting for leases will have a significant effect on our industry, and we would be pleased to discuss any of these matters with you and provide any additional information you may find helpful in addressing these important issues.

Very truly yours,

David K. Owens

DKO:ds

List of Attachments

- **APPENDIX A**-Application of Proposed Accounting Standards Update to Power Purchase Agreements.
EEI's member companies have experienced difficulty over the years in the application of ASC 840-10-15-6 (formerly EITF 01-8, paragraph 12) to determine when the terms of a power purchase agreement (PPA), in substance, convey the right to use the underlying power plant to the purchaser of the energy. The criteria provided in that guidance have been essentially carried over to the Proposed Accounting Standards Update – Leasing (Topic 840) (The Exposure Draft or ED) in paragraph B4. We have two areas of concern:

1. Because the ED proposes significantly different accounting for those PPAs determined to contain leases and those PPAs that will continue to be accounted for as executory contracts, the importance of appropriately distinguishing between the two types of contracts is more critical than ever. Historically, there has been significant diversity in practice in the interpretation of the criteria found in paragraph B4(e) for assessing when the right to use property, plant, or equipment has been conveyed in a PPA.

2. Once a PPA has been determined to contain a lease element, proper identification of the payments that convey the right to use the power plant (from among all payments under the PPA) is critical for appropriate measurement of the rights and obligations associated with the lease element.

This Appendix contains the following sections:

Section I – Criteria for Conveyance of the Right to Use the Underlying Asset
In this section we describe the differences in interpretation of the current criteria for determining when the right to use the underlying asset has been conveyed, the reasons why we believe that, even if interpreted similarly, the criteria may not be effective for making an appropriate distinction between a lease and an executory contract, and recommend alternative principles-based criteria for making this determination.

Section II – Identification of the Lease Elements in a Contract
Once it has been determined that a PPA contains a lease, guidance is needed to appropriately segregate the payments related to the right to use the underlying asset from the payments for other elements, such as the sale of energy or renewable energy certificates.

While we have attempted to describe the issues inherent in applying the provisions of the ED to PPAs and to offer recommendations to address those issues, we expect that a number of these issues may require further explanation and discussion. We would be happy to work with the Board and/or FASB staff to answer any questions and work through alternatives as a final standard is developed.
Section I

Criteria for Conveyance of the Right to Use the Underlying Asset

Paragraph B4 of the ED states that a contract conveys the right to use an asset if it conveys to an entity the right to control the use of the underlying asset during the lease term. In a typical PPA, physical access to the plant is not granted to the power purchaser, and the owner continues to operate its power plant. Accordingly, paragraphs B4(c) and (d) rarely factor into the evaluation of whether a PPA conveys the right to control the use of the underlying asset. Our focus, therefore, is on the application of paragraph B4(e).

Paragraph B4(e) uses the following criteria to identify when a PPA (or other contract) contains an in-substance lease arrangement:

The entity will obtain all but an insignificant amount of the output or other utility of the asset during the term of the lease, and the price that the entity 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. If the price that the entity will pay is contractually fixed per unit of output or at the current market price as of the time of delivery of the output, then the entity is paying for a product or service rather than paying for the right to use the underlying asset.

There are two primary areas of diversity in interpretation of paragraph B4(e):
1. What is meant by the price being “contractually fixed per unit of output,” and
2. What constitutes an output.
Each of these areas is discussed below.

1. Contractually fixed price per unit of output

In the application of the guidance in ASC 840-10-15-6(c), there have existed differing views among the accounting firms and industry participants as to what is meant by the term “contractually fixed” in the pricing of the output or other utility. Historically, some have taken a literal view that a contractually fixed price means that the contract specifies one single price for each and every unit of output that does not change for the entire term of the contract. Others have taken an approach designed to differentiate between pricing that looks more like the purchase of a product or service (considered a contractually fixed price per unit of output, even when that pricing may contain some variability) from pricing that conveys the right to control the use of the underlying asset over a period of time. In our experience, we have seen contracts that had various pricing mechanisms that could be construed to be “contractually fixed”. A number of example PPAs are discussed below with the following common facts:
Energy Corp owns and operates a power plant. Energy Corp enters a 5-year PPA with Utility Corp to sell to Utility Corp all energy produced by the facility.

**Contract 1 -- Monthly capacity payment and fixed per megawatt hour (Mwh) energy payment**
Utility Corp pays $50,000 per month, regardless of the quantity of energy purchased. Utility Corp pays $40 per Mwh of energy purchased.

Because the monthly payment is made regardless of the quantity of energy purchased, the price per unit of energy output is not considered to be contractually fixed. The monthly payment is a time-based payment that conveys the right to Utility Corp to purchase all output of the power plant. Most would consider this arrangement to be a lease under paragraph B4(e). *(Note that this conclusion could change if capacity is considered to be an output as discussed later in this appendix).*

Other PPAs as discussed in Contracts 2 through 10 below, have no fixed monthly payment, but provide only for a price per Mwh purchased, with a number of possible pricing structures:

**Contract 2 - Fixed price per unit of output for the entire term of the contract.**
Utility Corp pays $50 per Mwh of energy purchased.

In this situation, there is no question that the pricing meets the requirement as contractually fixed pricing and the contract would not be a lease.

**Contract 3 -- Price per unit of output adjusts over time according to a fixed pricing schedule in the contract.**
The PPA has a schedule of pricing as follows:
Year 1 - Utility Corp pays $45 per Mwh purchased
Year 2 - Utility Corp pays $47 per Mwh purchased
Year 3 - Utility Corp pays $50 per Mwh purchased
Year 4 - Utility Corp pays $52 per Mwh purchased
Year 5 - Utility Corp pays $55 per Mwh purchased

Alternatively, the PPA could state a price of $45 per Mwh purchased in year 1 that is increased by a specified fixed percentage in each of the following four years.

In this example, differing conclusions have been reached as to whether or not this pricing is contractually fixed per unit of output:
- The literal view would hold that because different units of output have different prices the price per unit is not fixed.
- Another view would hold that that the price is fixed for all units, albeit at different amounts, so the requirement is met.

**Contract 4 -- Price per unit of output is different for time of day delivered.**
Utility Corp pays $50 per Mwh purchased during on-peak hours
Utility Corp pays $20 per Mwh purchased during off-peak hours
The difference in pricing reflects the relative difference in market pricing (at inception of the PPA) for the different times of day.

In this example, entities have reached differing conclusions as to whether or not this pricing is contractually fixed per unit of output for the same reasons as in Contract 3.

**Contract 5 - Price per unit of output is initially fixed with annual adjustment for inflation.**
Utility Corp pays an initial price of $45 per Mwh purchased during year 1. At the beginning of the second year and each subsequent year, the price per unit is adjusted by the change in an index (e.g., CPI) for the most recently completed year.

In this example, entities have reached differing conclusions as to whether or not this pricing is contractually fixed per unit of output. While the price for future years is not determinable at inception of the contract, the price is based on a fixed formula per unit delivered, and the variability in the price is unrelated to volume of output.

**Contract 6 – Price per unit of output depends on the outcome of a contingency.**
Utility Corp pays $50 per Mwh purchased if the Energy Corp facility qualifies to receive production tax credits (PTCs). Utility Corp pays $80 per Mwh purchased if the facility does not qualify or loses its qualified status for PTCs.

In this example, entities have reached differing conclusions as to whether or not this pricing is contractually fixed per unit of output.

**Contract 7 – Price is a fixed formula per unit of output.**
Utility Corp pays a price based on a fixed predetermined formula per unit of output. The inputs to the formula are based on future amounts (e.g., natural gas index, etc.) which relate to the cost of the output. While there is variability in the price, the price per unit does not vary based on the level of output, and can be viewed as reasonable manner of pricing a product. However, a payment is made only for units actually produced and delivered.

In this example, entities have reached differing conclusions as to whether or not this pricing is contractually fixed per unit of output for the same reasons noted for Contract 5.

**Contract 8 – Price per unit of output may be adjusted for changes in property taxes.**
Utility Corp pays $50 per Mwh purchased. The PPA states that the price includes an estimate of $0.30 per Mwh for property taxes, and that the per Mwh charge will increase/decrease by $0.03 per Mwh for changes, in $100,000 increments, to projected real estate taxes of $1 million.

In this example, entities have reached differing conclusions as to whether or not this pricing is contractually fixed per unit of output. It raises the question of whether
executory costs or charges for other services should be excluded in the determination of whether the price per unit of output is contractually fixed.

**Contract 9 - Price per unit of output is reduced over a certain production threshold.**
Utility Corp pays $50 per Mwh purchased for all energy production from the facility. If production exceeds 115% of the annual committed energy, the price for the incremental units drops to $25 per Mwh purchased.

In this example, some have concluded that the price is not contractually fixed per unit of output because the price varies with the level of production. However, others believe that this pricing is a practical manner of pricing a product that encourages the plant owner to forecast production as accurately as possible, rather than conveying the right to use the plant.

**Contract 10 - Price per unit of output is fixed, but purchaser can curtail delivery of the energy.**
Utility Corp pays $50 per Mwh for all energy generated.
Utility Corp has the ability to curtail (not accept) delivery of the energy in certain circumstances (such as to protect the integrity of the electric grid). When energy is curtailed, Utility Corp must still pay for the curtailed energy (based on a predetermined level of production).

In this example, some have concluded that the price is not contractually fixed per unit of output because payment must be made whether or not the energy is delivered. However, others believe that the decision to curtail is unrelated to the time the plant is available for use and represents an ancillary provision to the substance of the overall contract which is to purchase energy.

One of the key objectives noted by the Boards in developing new accounting guidance for leases is to eliminate the lack of comparability between similar transactions as a result of the existing bright-line distinction between capital leases and operating leases. Even if there was consistent interpretation of the meaning of “contractually fixed price per unit of output” within our industry, we believe that the application of the guidance proposed in the ED could potentially result in different accounting for virtually identical PPAs. The diversity in interpretation of what constitutes a fixed price per unit only compounds the problem. For example, contracts 2 and 5 above are essentially similar contracts, which would be recognized and reported in the financial statements in very different ways:

<table>
<thead>
<tr>
<th></th>
<th>Contract 2</th>
<th>Contract 5</th>
</tr>
</thead>
<tbody>
<tr>
<td>Right-of-use asset</td>
<td>N/A</td>
<td>(fixed price) recorded on balance sheet</td>
</tr>
<tr>
<td>Lease obligation</td>
<td>N/A</td>
<td>adjusted for CPI recorded on balance sheet</td>
</tr>
<tr>
<td>Gross margin</td>
<td>included as power lease portion - excluded</td>
<td></td>
</tr>
<tr>
<td>Amortization expense</td>
<td>N/A</td>
<td>included</td>
</tr>
</tbody>
</table>
We believe that accounting for these two contracts in vastly different manners, when they were entered into for similar business purposes and are virtually identical economically, will result in undue lack of comparability.

Paragraph BC31 in the Basis for Conclusions of the ED makes an important point that payments specified in terms of the time that the underlying asset is made available for use, rather than in terms of the output from the asset, may meet the definition of a lease. Paragraph BC32 further states that if the price that the purchaser will pay is specified per unit of output, the purchaser is paying for a product or service rather than the right to use the asset.

In our opinion, focusing on these key concepts will provide a better way of distinguishing between an executory contract and a lease than is provided by the current criteria. The criterion that a price is "contractually fixed per unit of output," as interpreted by most, does not appropriately identify all agreements where the substance is the purchase of a product. As noted in the example contracts above, there are many forms of pricing that, while they may contain some variability, are common ways of pricing the sale of a product and do not convey the right to use an asset.

Recommendation:
We recommend the following amendments to paragraph B4 (blacklined below):

A contract conveys the right to use an asset if it conveys to an entity the right to control the use of the underlying asset during the lease term. The right to control the use of the underlying asset is conveyed if any one of the following conditions is met:

(c) The entity has the ability or right to operate the asset or direct others to operate the asset in a manner that it determines while obtaining or controlling more than an insignificant amount of the output or other utility of the asset.

(d) The entity has the ability or right to control physical access to the underlying asset while obtaining or controlling more than an insignificant amount of the output or other utility of the asset.

(e) The entity will obtain all but an insignificant amount of the output or other utility of the asset during the term of the contract, and the contract payments are specified in terms of the time that the underlying asset is made available or reserved for the benefit of the entity, rather than in terms of the output from the asset.

Indicators that a contract contains the characteristics of a purchase of output would include, but not be limited to, pricing based on any of the following pricing mechanisms: (1) a fixed price per unit of output, (2) a predetermined price or formula per unit of output, (3) a formula for units of output based on variable prices of inputs, market prices of the same or similar...
outputs, or inflation adjustments, or (4) a current market price as of the time of delivery of the output.

In contrast, pricing mechanisms that indicate that a contract contains characteristics of a lease include: (1) pricing based on term (i.e., the passage of time) without regard to quantity of output, or (2) pricing that does not allow for a reduction in payments if the expected output is not achieved or accepted during all or a portion of the term, and the price that the entity 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, then the entity is paying for a product or service rather than paying for the right to use the underlying asset.

Application of the recommended language would result in the conclusions that example contracts 2 through 9 discussed above do not contain leases. Contract 1 would likely be a lease unless the monthly payment is priced in units of capacity for which the payments are reduced when the plant is unavailable. Contract 10 is considered to contain a lease. Even though the contract is priced per unit of output, that per unit price must be paid even when energy is not delivered, making it an in-substance time-based payment.

2. Determining the “output” in application of paragraph B4(c)

PPAs may include the sale of electricity, capacity, and/or renewable energy certificates (RECs), as well as a number of ancillary services. Those products may be sold to one counterparty or, alternatively, could be sold to two or three different counterparties. The following explanations of capacity and RECs are useful for this discussion:

Capacity - Capacity is the capability to produce energy. Capacity may be sold bilaterally or in capacity auctions in certain markets. In some cases, an entity may purchase capacity for regulatory purposes without the right to purchase the energy from the underlying plant. In other cases, a capacity charge may represent a reservation fee, giving the purchaser the right, but not the obligation, to purchase any energy generated by a specific plant.

REC - Renewable energy certificates are the non-physical property rights to the environmental benefits associated with renewable energy production. RECs can be sold separately in bilateral markets to transfer the value of the environmental benefits to other owners. RECs do not require interaction with the government to realize their value, unlike tax credits and grants. RECs are produced if the plant runs, but are not produced if the plant does not run. Further, a REC is a product that can differ tremendously by regulatory jurisdiction. Sometimes, RECs are differentiated by type (photovoltaic solar vs. wind vs. bio-mass); in jurisdictions requiring specific yet scarce types, RECs may be the primary economic element or incentive within a renewable contract. In other cases, RECs are differentiated by state (in-state RECs vs. out-of-state RECs). Thus, the markets for RECs are in different stages of development and can be characterized as fragmented and evolving, leading to differing conclusions regarding fungibility, liquidity, and value.
Some view energy (electricity) as the only output of a power plant. Others view capacity as an additional output or other utility when it can be sold separately from the energy. Some view RECs associated with renewable plants as an output or other utility, while others do not. The views against RECs being considered outputs have generally been based on a presumption that these products (even if able to be sold separately) are not “physical” outputs directly produced by a facility, but rather are government incentives (similar to tax incentives) created to promote the construction of renewable facilities.

However, those who view these products as outputs generally favor a broader interpretation of “output or other utility” that will be “produced or generated” by a facility (emphasis added). The fact that these products are integrally tied to the facility (either by its ability to produce in the case of capacity, or linkage to physical energy production in the case of RECs), combined with the ability to sell these products separately in many markets and their commensurate value, suggests to these entities that they have separate value or “utility”. Further, these entities would argue that without the RECs, the value proposition for entering into a renewable PPA is significantly diminished, and in some cases almost all of the economic benefit of a PPA is directly associated with the RECs in regional jurisdictions where specific types of scarce renewable generation are required as part of the supply portfolio.

The determination of which elements are considered “outputs or other utility of the asset” is important when evaluating a contract under the proposed leasing model. This determination impacts the judgments around (1) determining whether a single party obtains all but an insignificant amount of the output or other utility and (2) identifying whether the contract as a whole is a lease or the contract contains a leasing element. We have provided examples that demonstrate the impact this determination may have on each of these judgments.

First, if energy, capacity and RECs (or other identified products) are sold to different parties, this determination will affect the evaluation of whether any of those entities will obtain all but an insignificant amount of the output of the power plant during the contract term. Consider an example where one counterparty purchases the capacity and energy from a plant, and a different counterparty purchases the RECs. If RECs are considered an output, and the value of the RECs is considered significant, then no one party is taking substantially all of the output of the plant and the contract would likely not be classified as a lease. If RECs are not considered an output, then the party buying the capacity and energy is taking substantially all of the output and the contract might be accounted for as a lease if the pricing criteria are met.

Second, the determination of whether RECs and capacity are considered output or other utility of the plant will affect the evaluation of whether the contract as a whole is a lease or the contract contains a leasing element. If each product is determined to be an output, the pricing associated with each product would be evaluated separately to determine if the price for that product is contractually fixed per unit of output or equal to the current market price per unit of output as of the time of delivery of the product. Evaluation of the separate outputs could result in a different conclusion about whether or not the contract contains a lease than looking at the total contract price relative to the units of energy purchased. For example, if capacity is considered an output, a fixed price per kw/month of capacity would indicate that the capacity payments do not represent lease payments (assuming the payment is reduced for...
units of capacity not delivered). However, if capacity is not considered an output, the total payments under the contract relative to the units of energy delivered would not result in a fixed price per unit of energy delivered and the contract would be deemed to contain a lease.

**Recommendation:**

We recommend that the Boards provide clarification on the definition of “output or other utility” within paragraph B4 by expanding on the concept of “other utility” to include items which (a) are directly related to the physical characteristics or production of the underlying asset, (b) convey economic or other financial benefits to the purchaser, and (c) have standalone value and/or can be sold separately on a standalone basis (similar to the provisions within paragraph 23(b) of the Revenue Recognition ED).
Section II

Identification of the Lease Elements in a Contract

When a determination has been made that a PPA contains a lease, an entity must then identify the payments in the PPA that relate to the right to use the underlying asset. Only the payments related to the right to use the underlying asset should be considered in measuring the related lease assets and liabilities to be recorded in the financial statements.

PPAs that have been determined to contain a lease will frequently also contain other elements, such as the sale of energy and/or RECs, the purchase of fuel, or service components. Paragraph B5 of the ED states: “An entity shall apply the proposals in the boards’ exposure drafts on revenue from contracts with customers to identify separate performance obligations within a contract that contains both service components and lease components.” That guidance indicates when the service component should be accounted for separately from the lease element and provides guidance on how to allocate contract payments between the service components and the lease components; however, there is no guidance for allocating contract payments to other elements in the contract.

We recommend including language similar to that contained in ASC 840-10-15-17 through 15-19, which would clarify that:

(1) If a contract contains lease as well as non-lease elements, the recognition, measurement, and disclosure provisions of Topic 840 should be applied by both the purchaser and supplier to the lease element of the contract,

(2) Other elements of the contract not within the scope of Topic 840 should be accounted for in accordance with other applicable generally accepted accounting principles, and

(3) Payments under the contract should be allocated at inception of the contract or upon a reassessment of the contract into (a) those for the lease and (b) those for the other non-lease elements.

Two examples are used throughout this section to illustrate the importance of separating the lease and non-lease components and to discuss several views about how to perform the allocation.

Example 1
Assume Utility Co has entered into a five-year PPA to purchase energy from a natural gas-fired plant. Utility Co pays a $1 million per month reservation fee, regardless of quantity of energy purchased. Utility Co also has the right, but not the obligation, to purchase all energy produced by the 300mw plant at a price based on the following formula: natural gas index multiplied by the plant’s heat rate of 8 (measure of the efficiency of the plant in converting fuel to electricity). Utility Co has reached the conclusion that the contract contains a lease. The fair value of the plant is estimated
to be $300 million and it has a 40 year estimated useful life. Utility Co’s incremental borrowing rate is 6%.

The market price of natural gas is $5 per MMBtu (which converts to $40 per Mwh based on heat rate of 8). The plant is capable of producing approximately 216,000 Mwh (300mw x 24 hours x 30 days) each month. However, based on forward curves for energy, Utility Co is expected to purchase 180,000 Mwh each month, making the total expected monthly payment for energy equal to $7.2 million per month (180,000 Mwh x $40 per Mwh).

**Example 2**

Assume Utility Co has entered into a 20-year PPA to purchase all the output from a 200mw wind plant. Seller has guaranteed a minimum generation of energy each month. Utility Co pays $55 for each Mwh of energy produced and receives one REC for each Mwh produced. Utility Co has the ability to curtail (not accept delivery of) energy at its discretion, but must pay the same price per Mwh curtailed based on historical production quantities. Utility Co has reached the conclusion that the contract contains a lease. Estimated monthly production from the plant is 43,200 Mwhs (200mw x 30% capacity factor x 30 days x 24 hours), making the total estimated payment per month approximately $2.4 million. The fair value of the plant is estimated to be $400 million and it has a 25 year estimated useful life. Utility Co’s incremental borrowing rate is 6%.

The importance of separating the lease and non-lease components is illustrated below using Example 1. If all payments in Example 1 were considered lease payments, the following right-of-use asset would be computed:

<table>
<thead>
<tr>
<th>Reservation Fee</th>
<th>$1.0M</th>
</tr>
</thead>
<tbody>
<tr>
<td>Energy Payments</td>
<td>7.2M</td>
</tr>
<tr>
<td>Monthly Payment</td>
<td>$8.2M</td>
</tr>
<tr>
<td>Total Months</td>
<td>x 60</td>
</tr>
<tr>
<td>Total Payments</td>
<td>$492M (PV @ 6% rate = $424M)</td>
</tr>
</tbody>
</table>

Omitting energy payments from the calculation yields a right-of-use asset of $52M.

The monthly depreciation for plant owner is calculated below. As noted earlier, the fair value of the asset is $300 million. The value of the right to use the asset for 5 years should not exceed the total fair value of the asset.

<table>
<thead>
<tr>
<th>Fair Value of Plant</th>
<th>$300M</th>
</tr>
</thead>
<tbody>
<tr>
<td>Useful Life (months)</td>
<td>480</td>
</tr>
<tr>
<td>Monthly Depreciation</td>
<td>$625k</td>
</tr>
</tbody>
</table>
The following table compares monthly amortization when energy payments are included and excluded from the calculation of the right-of-use asset.

<table>
<thead>
<tr>
<th></th>
<th>Energy Considered Lease Element</th>
<th>Energy NOT Considered Lease Element</th>
</tr>
</thead>
<tbody>
<tr>
<td>Right of Use Asset</td>
<td>$424M</td>
<td>$52M</td>
</tr>
<tr>
<td>PPA Term (months)</td>
<td>60</td>
<td>60</td>
</tr>
<tr>
<td>Monthly Amortization</td>
<td>$7M</td>
<td>$862K</td>
</tr>
</tbody>
</table>

The comparison above shows that the right-of-use asset and related amortization expense are substantially higher when energy costs are included. Excluding energy costs yields a right-of-use asset and amortization expense that closely approximates the value of the right of use conveyed to the lessee, which is more akin to the actual owner’s cost over the related period in depreciation expense. As such, we believe that it is critical that the final standard include guidance that addresses the other elements of a contract that, if inappropriately considered to be lease elements, would lead to an inaccurate valuation of the right-of-use asset.

**Allocation of Contract Payments to the Lease and Non-Lease Elements**

EEI recommends that guidance about the methodology for allocating contract payments be added to the final guidance. Among our members there exist different views about the most appropriate manner of allocation, although all members agree that the lease and non-lease elements of a contract should be separated and that only the lease component should be accounted for under Topic 840.

The methodology to be used to allocate contract payments to the lease and non-lease elements is not clear. The ED refers to the Revenue Recognition ED for allocating contract payments between lease and service elements, so it seems reasonable to assume that guidance would also be used for allocating contract payments to other non-lease elements. We note, however, that paragraph 6 of the Revenue Recognition ED specifically excludes lease contracts from its scope, which adds confusion to determining the appropriate method for allocation.

Several views about how the contract payments should be allocated to the lease and non-lease elements are discussed below. We focus on the following two approaches:

- **Hypothetical operator approach** where the amounts allocated to the contract elements are based on the costs of production, and
- **Purchaser of lease rights and outputs approach** where the amounts allocated to the contract elements are based on the market price of the output being sold.

Under each approach, we discuss the following two methods:

- **Standalone selling price method** where the transaction price is allocated to the each contract element based on its standalone selling price, and
• Residual method where the transaction price is first allocated the non-lease elements that have an observable market value with the remaining transaction price representing the right-of-use asset.

We discuss each of the four views in greater detail below. We have also used the two examples from above (PPAs with a gas fired plant and a wind plant) to demonstrate the different accounting treatment that results under each view. Using the above two examples, we have prepared a table at the end of this section which compares the different accounting treatments that may result without clarity around this issue.

**The “Hypothetical Operator” Approach**

Views A and B below utilize a “hypothetical operator” approach to allocation. Proponents of this approach believe that once a contract has been determined to contain a lease, the purchaser would assume that it actually leased the power plant from the seller and is responsible for its operations. For example, in a traditional natural gas-fired power plant, a lessee-operator would make payments for its lease of the plant as well as payments for the costs of producing electricity (e.g., natural gas [fuel], labor, etc.). Accordingly, the amounts to be allocated to the non-lease elements are based on the costs of production.

Note that in these examples we have assumed that the character of the non-lease elements would change to reflect the in-substance lease of the plant. That is, while the contractual performance obligations are for the seller/lessor to provide energy and/or RECs to the buyer/lessee, once it has been determined that the contract contains an in-substance lease, the nature of the non-lease payments become an in-substance purchase of fuel and operating and maintenance services. It would not make sense for an entity to both lease the plant and purchase energy and RECs. Another approach would be to retain the character of the contractually stated deliverables (energy and RECs) and simply use the costs of production as a proxy measurement of the value of the energy and RECs.

**View A – Standalone Selling Price Method (Hypothetical Operator)**

Under View A, an entity would follow the guidance provided in the Revenue Recognition ED to allocate contract payments to the lease and non-lease elements. Entities would identify the performance obligations in the contract and allocate the transaction price to each of the performance obligations based on relative standalone selling price.

Paragraphs 50 through 52 of the Revenue Recognition ED state:

50. An entity shall allocate the transaction price to all separate performance obligations in proportion to the standalone selling price of the good or service underlying each of those performance obligations at contract inception (that is, on a relative standalone selling price basis).

51. The best evidence of a standalone selling price is the observable price of a good or service when the entity sells that good or service separately. A contractually stated
price or a list price for a good or service shall not be presumed to represent the standalone selling price of that good or service. If a standalone selling price is not directly observable, an entity shall estimate it.

52. When estimating standalone selling prices, an entity shall maximize the use of observable inputs and shall apply estimation methods consistently for goods or services and customers with similar characteristics. Suitable estimation methods include the following:

(a) expected cost plus a margin approach—an entity could forecast its expected costs of satisfying a performance obligation and then add the margin that the entity would require for that good or service; and

(b) adjusted market assessment approach—an entity could evaluate the market in which it sells goods or services and estimate the price that customers in that market would be willing to pay for those goods or services. That approach might also include referring to prices from the entity’s competitors for similar goods or services and adjusting those prices as necessary to reflect the entity’s costs and margins.

The transaction price would be allocated among the performance obligations based on a relative standalone selling price basis. The standalone selling price of fuel should be observable in most markets. The standalone selling price for operations and maintenance services can be estimated based on contracts to provide these services. The standalone selling price of the right to use the underlying asset will be more difficult to estimate. Some have suggested using the fair value of the plant (less any residual value after the lease term) as a proxy for determining the standalone selling price of the lease portion of the contract.

Application of View A to Example Contracts

In these examples, the portion of the transaction price to be allocated to the non-lease elements is based on the costs of production, which would include fuel, labor and other operating and maintenance costs. For simplicity, we have considered only fuel costs (ignoring other operating and maintenance costs) and have evaluated only one month of the contract rather than the entire contract term.

Example 1

In Example 1, two distinct performance obligations have been identified: the purchase of fuel and the conveyance of the right to control the use of the underlying asset. The transaction price must then be allocated between the two performance obligations. It seems intuitive that the $1 million per month reservation fee represents the payment for the right to use the asset. However, according to paragraph 51 of the Revenue Recognition ED a contractually stated price cannot be presumed to represent the standalone selling price of that good or service. The standalone selling price of the right to use the asset is based on the estimated fair value of the plant of $300 million. Assuming the 40 year estimated useful life and an incremental borrowing rate of 6%,
an estimated monthly selling price for the right to use the asset of approximately $1.7 million per month is computed. The market price of natural gas is $5 per MMBtu. As described above, Utility Co is expected to purchase 180,000 Mwh each month, making the total standalone selling price per month for fuel equal to $7.2 million per month ([180,000 Mwh x heat rate of 8 = 1.44 million units of fuel required] x $5 per MMBtu of fuel).

Calculation of relative standalone selling price:

<table>
<thead>
<tr>
<th>Description</th>
<th>Amount</th>
<th>Percentage</th>
</tr>
</thead>
<tbody>
<tr>
<td>Lease amount (at estimated standalone selling price)</td>
<td>$1.7M</td>
<td>(19%)</td>
</tr>
<tr>
<td>Total non-lease payments (at standalone selling price)</td>
<td>$7.2M</td>
<td>(81%)</td>
</tr>
<tr>
<td>Total payments at standalone selling prices</td>
<td>$8.9M</td>
<td></td>
</tr>
</tbody>
</table>

Total payments under the contract are expected to be $1 million per month for the reservation fee and $7.2 million (180,000 Mwh x $40 per Mwh) in energy payments, for a total contract payment of $8.2 million per month.

Applying the relative standalone selling price percentages to the actual contract payments results in the following allocation:

<table>
<thead>
<tr>
<th>Description</th>
<th>Amount</th>
<th>Percentage</th>
</tr>
</thead>
<tbody>
<tr>
<td>Allocation to lease amount ($8.2M x 19%)</td>
<td>$1.6M</td>
<td></td>
</tr>
<tr>
<td>Allocation to fuel ($8.2M x 81%)</td>
<td>$6.6M</td>
<td></td>
</tr>
<tr>
<td>Total actual contract payments</td>
<td>$8.2M</td>
<td></td>
</tr>
</tbody>
</table>

The fuel purchase element is then evaluated for derivative accounting treatment. If the fuel purchase element of this contract were determined to be a derivative that was marked to market, it appears that the purchaser/lessee, upon entering this contract, would record the fuel purchase portion of the contract at fair value (by reference to paragraph 7 of the Revenue Recognition ED) and would record a day one gain on this transaction since the amount allocated to the fuel purchase is below the market price. Similarly, the seller would record a day one loss.

**Example 2**
In Example 2, because there is no purchase of fuel required to operate a wind plant, and because the operating and maintenance services are ignored, only one distinct performance obligation has been identified: the conveyance of the right to control the use of the underlying asset. None of the transaction price is allocated to the non-lease elements and the entire amount paid per Mwh will be allocated to the lease element (right-to-use).

**View B – Residual Method (Hypothetical Operator)**

Proponents of View B believe that because leases are specifically scoped out of the Revenue Recognition ED, another method of allocation is appropriate. Under View B, the non-lease elements of the contract are carved out based on the fair value of the costs of production. In a PPA, market pricing will generally be available for fuel and estimable for operations and maintenance services. Any remaining contract payments are considered to represent the portion of the contract payments to be allocated to the right to use the underlying plant.
Application of View B to Example Contracts

Example 1
In Example 1, two distinct performance obligations have been identified: the purchase of fuel and the conveyance of the right to use the underlying asset. The transaction price must then be allocated between the two performance obligations.

As noted above, there is an observable market price for fuel of $5 per MMBtu. Based on the plant’s heat rate of 8 combined with the expected purchase of 180,000 Mwh’s, this requires procurement of 1.44 million units (MMBtus) of fuel. As noted in the application of View A to Example 1, total actual contract payments are expected to be $8.2 million. Fuel purchases at fair value would be $7.2 million (180,000 Mwh x heatrate of 8 x $5/MMBtu). This amount is allocated to the non-lease elements, in this case, the fuel purchase. The residual payments of $1 million would be allocated to the right to use the underlying asset.

Example 2
In Example 2, because there is no purchase of fuel required to operate a wind plant, and because the operating and maintenance services are ignored, only one distinct performance obligation has been identified: the conveyance of the right to control the use of the underlying asset. None of the transaction price is allocated to the non-lease elements and the entire amount paid per Mwh will be allocated to the lease element (right-to-use).

Purchaser of Lease Rights and Outputs Approach

Views C and D assume that the purchaser has leased the underlying asset, and is also purchasing the outputs of said asset. Under these views, the purchaser should assess the relative fair value of each item being purchased through the contract (e.g., the lease of the facility, the purchase of energy and/or the purchase of RECs) and allocate the transaction price accordingly.

View C – Standalone Selling Price Method (Purchaser of Lease Rights and Outputs)

Under View C, an entity would follow the guidance provided in the Revenue Recognition ED to allocate contract payments to the lease and non-lease elements. Entities would identify the performance obligations in the contract and allocate the transaction price to each of the performance obligations based on relative standalone selling prices of the right to use the asset, and each of the other items being bought/sold in the contract (e.g., energy, RECs, fuel, ancillary services).

The standalone selling prices of energy, fuel and/or RECs should be observable in most markets. The standalone selling price of the right to use the underlying asset will be more difficult to estimate. Some have suggested using the fair value of the plant (less any residual value after the lease term) as a proxy for determining the standalone selling price of the lease portion of the contract.
Application of View C to Example Contracts

In both example contracts, the sale of energy is considered a separate performance obligation because the seller either sells, or could sell, the power separately from the other elements in the contract. In Example 2, the sale of RECs is also considered a separate performance obligation because RECs can be sold separately from the energy and/or right to use the asset. For simplicity, we have evaluated only one month of the contract rather than the entire contract term.

Example 1
In Example 1, two distinct performance obligations have been identified: the sale of energy and the conveyance of the right to use the underlying asset. The transaction price must then be allocated between the two performance obligations. It seems intuitive that the $1 million per month reservation fee represents the payment for the right to use the asset. However, according to paragraph 51 of the Revenue Recognition ED, a contractually stated price cannot be presumed to represent the standalone selling price of that good or service. The standalone selling price of the right to use the asset is based on the estimated fair value of the plant of $300 million. The plant’s estimated useful life is 40 years. Assuming an incremental borrowing rate of 6%, a monthly selling price for the right to use the asset of approximately $1.7 million per month is computed. The market price of energy is $50 per Mwh, which is also considered to be its standalone selling price. The plant is capable of producing approximately 216,000 Mwh (300mw x 24 hours x 30 days) each month. However, based on forward curves for energy, Utility Co is expected to purchase 180,000 Mwh each month, making the total standalone selling price per month for energy equal to $9 million per month (180,000 Mwh x $50 per Mwh).

Calculation of relative standalone selling price:

<table>
<thead>
<tr>
<th>Reservation fee (at estimated standalone selling price)</th>
<th>$ 1.7M</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total energy payments (at standalone selling price)</td>
<td>9.0M</td>
</tr>
<tr>
<td>Total payments at standalone selling prices</td>
<td>$10.7M</td>
</tr>
</tbody>
</table>

Assuming the natural gas index at inception is $5 per MMBtu, the actual price for energy at inception would be $40 per Mwh ($5 gas index x heat rate of 8'). Therefore total payments under the contract are expected to be $1 million per month for the reservation fee and $7.2 million ($180,000 Mwh x $40 per Mwh) in energy payments, for a total contract payment of $8.2 million per month.

Applying the relative standalone selling price percentages to the actual contract payments results in the following allocation:

| Allocation to lease ($8.2M x 16%)              | $ 1.3M |
| Allocation to energy payments ($8.2M x 84%)    | 6.9M   |
| Total actual contract payments                  | $ 8.2M|

The energy purchase element is then evaluated for derivative accounting treatment. If the energy purchase element of this contract were determined to be a derivative that
was marked to market, it appears that the purchaser/lessee, upon entering this contract, would record the energy purchase portion of the contract at fair value (by reference to paragraph 7 of the Revenue Recognition ED) and would record a day one gain on this transaction since the amount allocated to the fuel purchase is below the market price. Similarly, the seller would record a day one loss.

**Example 2**

In Example 2, three separate performance obligations have been identified: the sale of energy, the sale of RECs and the conveyance of the right to use the underlying asset. The transaction price must then be allocated between the three performance obligations.

The standalone selling price of the right to use the asset for 20 years is based on the estimated fair value of the plant of $400 million. The plant's estimated useful life is 25 years. Assuming an incremental borrowing rate of 6%, a monthly standalone selling price for the right to use the asset of approximately $2.6 million per month is calculated. The market price of energy is $50 per Mwh, which is also considered to be its standalone selling price. RECs can be sold separately for $5 per REC. The plant is expected to produce approximately 43,200 Mwhs per month, making the total standalone selling price per month for energy equal to $2.2 million per month (43,200 Mwh x $50 per Mwh).

The actual payments under the contract are expected to be $2.4 million per month (43,200 Mwh x $55 per Mwh).

**Calculation of relative standalone selling price:**

<table>
<thead>
<tr>
<th>Description</th>
<th>Amount</th>
<th>Percentage</th>
</tr>
</thead>
<tbody>
<tr>
<td>Lease amount (at estimated standalone selling price)</td>
<td>$2.6M</td>
<td>(52%)</td>
</tr>
<tr>
<td>Total energy payments (at standalone selling prices)</td>
<td>$2.2M</td>
<td>(44%)</td>
</tr>
<tr>
<td>Total REC payments (at standalone selling price)</td>
<td>$0.2M</td>
<td>(4%)</td>
</tr>
<tr>
<td>Total remaining payments at standalone selling prices</td>
<td>$5.0M</td>
<td></td>
</tr>
</tbody>
</table>

Applying the relative standalone selling price percentages to the actual contract payments results in the following allocation:

| Allocation to lease ($2.4M x 52%)     | $1.2M    |
| Allocation to energy payment ($2.4M x 44%) | $1.1M   |
| Allocation to REC payments ($2.4M x 4%)  | $0.1M    |
| Remaining actual contract payments     | $2.4M    |

The energy purchase element is then evaluated for derivative accounting treatment. If the energy purchase element of this contract were determined to be a derivative that was marked to market, it appears that the purchaser/lessee, upon entering this contract, would record the energy purchase portion of the contract at fair value (by reference to paragraph 7 of the Revenue Recognition ED) and would record a day one gain on this transaction since the amount allocated to the fuel purchase is below the market price. Similarly, the seller would record a day one loss.
View D – Residual Method (Purchaser of Lease Rights and Outputs)

Similar to View B, proponents of View D believe that because leases are specifically scoped out of the Revenue Recognition ED, another method of allocation is appropriate. Under View D, the non-lease elements of the contract are carved out based on the fair value of the non-lease items being bought/sold. In a PPA, market pricing will generally be available for energy, fuel, and RECs. Any remaining contract payments are considered to represent the incremental value of having a specified plant from which the energy will be generated and, accordingly, represents the portion of the contracts payments to be allocated to the right to use the underlying plant.

Application of View D to Example Contracts

Example 1
In Example 1, two distinct performance obligations have been identified: the sale of energy and the conveyance of the right to use the underlying asset. The transaction price must then be allocated between the two performance obligations.

There is an observable price for energy of $50 per Mwh. As noted in the application of View A to Example 1, total actual contract payments are expected to be $8.2 million. Energy payments at fair value would be $6 million ($180,000 Mwh x $50 per Mwh). The residual payments of $2.2 million would be allocated to the right to use the underlying asset.

Example 2
In Example 2, three separate performance obligations have been identified: the sale of energy, the sale of RECs and the conveyance of the right to use the underlying asset. The transaction price must then be allocated between the three performance obligations.

There are observable prices for energy and RECs of $50 per Mwh and $5 per REC. After allocation of the contract payments to these elements, there is no residual value to be allocated to the right to use component of the contract.
Comparison of Views A through D

The following tables summarize the difference in accounting results between the four different views presented above.

Example 1 – Natural Gas-Fired Plant

<table>
<thead>
<tr>
<th>Amount of monthly payment allocated to:</th>
<th>Hypothetical Approach</th>
<th>Operator</th>
<th>Purchaser of Lease Rights and Outputs Approach</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>View A Standalone Method</td>
<td>View B Residual Method</td>
<td>View C Standalone Method</td>
</tr>
<tr>
<td>Lease</td>
<td>$1.6M</td>
<td>$1.0M</td>
<td>$1.3M</td>
</tr>
<tr>
<td>Energy</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>Fuel</td>
<td>$6.6M</td>
<td>$7.2M</td>
<td>N/A</td>
</tr>
<tr>
<td>Total payment</td>
<td>$8.2M</td>
<td>$8.2M</td>
<td>$8.2M</td>
</tr>
</tbody>
</table>

Example 2 – Wind Plant

<table>
<thead>
<tr>
<th>Amount of monthly payment allocated to:</th>
<th>Hypothetical Approach</th>
<th>Operator</th>
<th>Purchaser of Lease Rights and Outputs Approach</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>View A Standalone Method</td>
<td>View B Residual Method</td>
<td>View C Standalone Method</td>
</tr>
<tr>
<td>Lease</td>
<td>$2.4M</td>
<td>$2.4M</td>
<td>$1.2M</td>
</tr>
<tr>
<td>Energy</td>
<td>N/A</td>
<td>N/A</td>
<td>1.1M</td>
</tr>
<tr>
<td>Fuel</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>RECs</td>
<td>N/A</td>
<td>N/A</td>
<td>1M</td>
</tr>
<tr>
<td>Total payment</td>
<td>$2.4M</td>
<td>$2.4M</td>
<td>$2.4M</td>
</tr>
</tbody>
</table>

As demonstrated by the tables above, the four different views result in very different outcomes for both of our examples. These different interpretations will lead to divergence in practice around the measurement of the right-of-use asset for the lease element of economically similar contracts.

Generally, our members believe that Views A and B, which base the allocation to the non-lease elements on the cost of production (i.e., the cost of services and inputs), best reflect the economics of a transaction under a contract in which the purchaser is deemed to have leased the underlying plant. To perform the allocation based on the relative standalone selling prices or fair values of the outputs (e.g., energy, RECs, etc.) creates a potential “overlap” of value. For example, the market price of energy inherently includes some value for the plant required to produce the energy, as well as the cost of inputs such as fuel and operations costs. Conversely, the fair value of the plant inherently includes the value of the output it is capable of producing.
Recommendation

We recommend that the final standard include further guidance regarding how the total consideration in a contract that has been determined to contain a lease should be allocated among the lease and non-lease elements, with some flexibility in the allocation process to best reflect the economics of the transaction. We point to the more substantial yet flexible guidance currently included within IFRIC 4 as an example, which provides for the general separation of lease and non-lease elements based on either relative fair values of the contractual elements (lease and output purchaser view) or based on a production/input cost method (operator view), and also provides for a residual approach for estimation of an element where relevant:

IFRIC 4, paragraphs 13 & 14

...Payments and other consideration required by the arrangement shall be separated at the inception of the arrangement into those for the lease and those for other elements on the basis of their relative fair values. The minimum lease payments...include only payments for the lease (i.e. the right to use the asset) and exclude payments for other elements in the arrangement (e.g. for services and the cost of inputs).

In some cases, separating payments for the lease from payments for other elements in the arrangement will require the purchaser to use an estimation technique. For example, a purchaser may estimate the lease payments by reference to a lease agreement for a comparable asset that contains no other elements, or by estimating the payments for the other elements in the arrangement by reference to comparable agreements and then deducting these payments from the total payments under the arrangement.