Exhibit No.:
Issues: *Fuel Adjustment Clause; ROE and Risk; Asbury SCR Project; Depreciation; Regulatory Plan Amortizations; Commission Rules Tracker/ Vegetation Management*
Witness: *Mark L. Oligschlaeger*
Sponsoring Party: *MoPSC Staff*
Type of Exhibit: *Surrebuttal Testimony*
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MISSOURI PUBLIC SERVICE COMMISSION

UTILITY SERVICES DIVISION

SURREBUTTAL TESTIMONY

OF

MARK L. OLIGSCHLAEGER

THE EMPIRE DISTRICT ELECTRIC COMPANY

CASE NO. ER-2008-0093

Jefferson City, Missouri
April, 2008

TABLE OF CONTENTS OF

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Q. Please state your name and business address.

A. Mark L. Oligschlaeger, P.O. Box 360, Suite 440, Jefferson City, MO 65102.

Q. Are you the same Mark L. Oligschlaeger who has previously filed direct and rebuttal testimony in this proceeding?

A. Yes, I am.

Q. What is the purpose of this testimony?

A. The purpose of this surrebuttal testimony is to address the rebuttal testimony of the witnesses for The Empire District Electric Company (Empire or Company) on the following topics: the testimony of H. Edwin Overcast on Fuel Adjustment Clause (FAC) and Return on Equity (ROE); the testimony of Brad A. Mertens on Asbury SCR In-Service; the testimony of Donald S. Roff on Depreciation; the testimony of Robert W. Sager on Amortization, and the testimony of Empire witness W. Scott Keith on Vegetation Management Costs.

EXECUTIVE SUMMARY

Q. Please summarize your surrebuttal testimony.

A. My surrebuttal testimony will discuss and support the following points:

1) Dr. Overcast incorrectly states the Staff's positions on matters involving the incentive structure of the Staff's proposed FAC and the presumption of prudence of the costs flowing through an FAC mechanism. He also presents an incomplete and misleading depiction of Empire's risk levels compared to other electric utilities by not taking into account Empire's current regulatory plan amortization (RPA) mechanism in evaluating Empire's overall level of risk.

2) Mr. Mertens errs in his rebuttal testimony in assuming that the in-service criteria in place for the Asbury SCR project somehow dictate the timing of the inclusion of this item in Empire's rate base for ratemaking purposes.

3) Mr. Roff is incorrect in asserting that the RPA mechanism in place "has nothing to do with" Empire's proposal to increase its depreciation rates in this proceeding.

4) The Staff disagrees with Mr. Sager's rebuttal testimony concerning RPAs when he rejects the proposal of Praxair, Inc. et al. (Industrial Interveners) witness Michael Gorman in his direct testimony to include a depreciation adjustment regarding purchase power agreements in the RPA calculation.

5) The Staff will present here some revisions to its proposal in my rebuttal testimony to handle certain costs involving vegetation management and infrastructure inspections through a "tracker" mechanism.

FUEL ADJUSTMENT CLAUSE

Q. What areas of Empire witness Overcast's rebuttal testimony regarding the fuel adjustment clause (FAC) issue will you be addressing?

A. I will address the portions of Dr. Overcast's testimony that pertain to the incentive effects of the Staff's FAC proposal and the standards for prudence that should apply to the FAC structure. Staff witness Lena M. Mantle will also be addressing certain aspects of Dr. Overcast's rebuttal testimony on the FAC issue in her surrebuttal testimony.

Q. At page 4 of his rebuttal testimony, Dr. Overcast states that "Both the Staff and Mr. Brubaker assume that the existence of a fuel clause designed to allow recovery of variable and unpredictable fuel costs will cause Empire to be imprudent or wasteful in the purchase of fuel and power." Do you agree with this characterization as it applies to the Staff's FAC structure?

A. Absolutely not. In designing its FAC proposal to present to the Commission in this proceeding, the Staff did not "assume" that Empire will be imprudent or wasteful in its future fuel and power procurement decisions under an FAC. The Staff's proposed FAC structure does properly recognize, however, that there are inherently stronger incentives for utility efficiency under traditional rate treatment of fuel and purchased power costs than under an FAC pass-through type mechanism. The Staff's proposed FAC structure attempts to prospectively address the effects on a utility of an FAC structure through Staff's proposal not to pass-through to customers 100% of any change in fuel/purchased power expense compared to base rate levels.

Q. Please explain the basis of your belief that there are inherently stronger incentives for utility precision and care under traditional rate regulation for fuel and purchased power costs than under an FAC mechanism.

A. Under traditional rate practices in Missouri, a utility must wait up to a maximum of 11 months from the point of filing for a change in its rates to reflect changes to its revenue requirement in its rates to actually receiving new rate levels. Also, under traditional regulatory practices the utility undergoes a full audit, including a prudence review, before being able to charge its customers for any increased expenses, including those incurred for fuel and purchased power expense.

In contrast, under an FAC rate mechanism, an electric utility will be able to pass on changes in its fuel and purchased power costs to customers much more quickly than under traditional Missouri ratemaking methods. Also, there will not be time under the procedures governing use of FAC mechanisms in this jurisdiction to do a meaningful audit or review of the factors changing a utility's fuel and purchased power costs prior to reflection of those changes to fuel and purchased power costs in the FAC rate. Any prudence review of these changes will be performed well after the fact of the rate change to customers under an FAC.

In the Staff's opinion, these differences between how traditional regulation operates and how an FAC operates will provide significantly less incentives for efficiency and care on a utility's part as it relates to its fuel and purchased power procurement and use decisions. Because of the fact that utilities will be more insulated from the financial consequences of fluctuations in their actual fuel and purchased power expense levels under an FAC structure compared to their financial exposure to such fluctuations under traditional ratemaking practices, the utility will have less incentive to be concerned with the overall level of fuel expense charged to its customers under a pass-through mechanism.

Q. What factors enhances a utility's incentives to be efficient and productive?

A. Other than regulatory oversight, the main incentives for utility efficiency and productivity are the ability of a utility to profit or gain from efficiency enhancements for a period of time, and conversely to bear the consequences of increased cost levels for a period of time. Under traditional regulation, the period between when a utility's costs change and when rates can be changed to reflect the new cost levels (i.e., "regulatory lag") allows a utility a meaningful opportunity to gain from or suffer from changes in its cost levels. Regulatory lag creates a powerful incentive for utility efficiency, in the Staff's opinion.

Q. Does an FAC mechanism substantially reduce the amount of regulatory lag applicable to fuel and purchased power costs?

A. Yes, it does.

Q. What mechanism is the Staff recommending in this case be used to enhance the incentives for utility efficiency and productivity that would otherwise be lost through a pass-through regulatory scheme such as an FAC?

A. The Staff is recommending that any FAC approved for use by the Commission not pass through 100% of the increases or decreases in a utility's fuel expenses to its customers, but instead have the utility retain a portion of the increased fuel costs or conversely retain a portion of the decreased fuel costs. In this case, the Staff is recommending that Empire retain 30% of any change in its fuel and purchased power costs, and pass through to customers the remaining 70%. The rationale and support for the specific 70%-30% split can be found in the Staff's Cost of Service Report, filed February 22, 2008.

Q. What does the Staff see as the benefit of this structure?

A. The benefit of this type of FAC structure is that it continues Empire's financial stake in the level of fuel costs it incurs at any point in time. By allowing Empire to benefit, in part, from reductions in fuel expense and to bear, in part, a loss in earnings from higher levels of expense, the utility is given strong incentives to manage and control its fuel and purchased power costs to the extent possible, even under an FAC structure.

Q. Is the Staff urging this type of structure based upon any particular concern on the ability or character of Empire management?

A. No, not at all. The Staff is not singling out Empire management. If there is to be an FAC, the Staff believes it to be beneficial to both the utility and its customers to employ an FAC structure that is designed to provide the utility with strong incentives for efficiency. Dr. Overcast's attempt to depict the Staff's proposal as implicitly impugning Empire's integrity or ability will not deter the Staff from performing its audit function. It seems that Dr. Overcast would argue that a business should not employ fundamental internal controls to protect its assets on the basis that instituting such controls would "assume" its employees were wasteful and dishonest.

Q. Has the Commission determined that 100% pass-through of all fuel and purchased power costs is not conducive to good regulatory incentives?

A. Yes. In its Report and Order in Case No. ER-2007-0004, Aquila, Inc., the Commission stated that "the easiest way to ensure a utility retains the incentive to keep fuel and purchased power costs down is to allow less than 100% pass through of those costs." (Report and Order, p. 53) The Commission went on to order pass-through of 95% of the changes in Aquila, Inc.'s fuel and purchased power costs through its FAC. In this case, however, the Staff asserts that it's recommended sharing percentages will provide for better incentives for an electric utility operating under an FAC than allowing a 95% pass-through of all changes to a utility's fuel costs.

Q. Won't the existence of prudence audits for the costs recovered through an FAC be an incentive for prudent utility management of its fuel and purchased power costs?

A. Prudence audits are one regulatory protection that is necessary in the context of an FAC pass-through mechanism. However, after-the-fact prudence reviews are no substitute for appropriate before-the-fact design of an FAC that provide for adequate incentives for management control and efficiency on a utility's management before the utility incurs the costs that will flow through the FAC.

Q. At page 11 of his rebuttal testimony, Dr. Overcast terms any amount of increased fuel and purchased power expense that the utility would not retain under the Staff's proposed FAC structure as being a "disallowance." Do you agree with this characterization?

A. No. This is an example of Dr. Overcast taking a concept applicable to traditional, all-factors-considered regulation and forcing it out of context into his discussion of the FAC mechanism. A disallowance occurs when a cost incurred by a utility within a test year, or possibly an update period or true-up period, is not included in rates in a general rate proceeding because it does not benefit ratepayers, is unreasonable, is not recurring in nature, is imprudent, etc. In contrast, if a utility was not able to fully recover significant increases in fuel and purchased power expense through an FAC because of the FAC provisions, it still retains the ability to initiate a general rate proceeding to seek full recovery of its fuel costs, if its overall financial position justifies that action. Of course, other parties theoretically would also have the ability to file an earnings complaint case (i.e., a general rate decrease case) if the utility were in the earnings position of being able to retain significant dollars from decreased levels of fuel and purchased power costs because Empire's overall earnings levels prove it to be in an excess earnings situation. The Staff does not view establishing reasonable recovery percentages in an FAC structure as constituting "disallowances" or "windfalls" from a regulatory perspective.

Q. Due to their recommendations for sharing of fuel expense changes under an FAC by the utility and its customers, Dr. Overcast accuses the Staff and the Industrial Interveners of violating the regulatory principle that "a utility has the right to recover prudently incurred expenses, and no more" (Overcast rebuttal, p. 2). Did Dr. Overcast omit any parties to this proceeding in his list of violators of this regulatory principle?

A. Yes. Dr. Overcast's client, Empire, has sponsored an FAC which would allow for sharing of increases and decreases in its fuel/purchased power costs between it and its customers. On its face, the Company's own proposed FAC structure violates some of the same regulatory principles that Dr. Overcast attacks the Staff and other parties in his rebuttal testimony for allegedly transgressing.

Q. Notwithstanding Empire's inconsistent arguments on this point, does the Staff agree with Dr. Overcast's assertion that the Company has the right to recover 100% of it prudently incurred expenses, and no more?

A. Not in the context of an FAC mechanism. The statute authorizing use of FACs in Missouri is clear that granting an electric utility use of an FAC is fundamentally a discretionary act by the Commission, and not something that a utility has a "right" to. Furthermore, if a Commission does not have to grant an FAC upon request to a utility, it hardly follows that once it decides to grant an FAC to an applicant that the Company then has a "right" to 100% recovery of prudently incurred fuel and purchased power costs under that regulatory structure. In fact, Commission Rule 4 CSR 240-20.090(2)(C) reads "The Commission may, at its discretion, determine what portion of prudently incurred fuel and purchased power costs may be recovered in a RAM and what portion shall be recovered in base rates." RAM is an acronym for "rate adjustment mechanism" which is defined in the Commission rules as meaning either an FAC or an interim energy charge. Dr. Overcast's arguments concerning 100% recovery of fuel costs under an FAC are baseless.

Q. On page 6 of his rebuttal testimony, Dr. Overcast criticizes the Staff's and the Industrial Interveners' recommended FAC structure for their "symmetry" of design; i.e., that the FAC proposals feature equal sharing percentages for changes in fuel costs, whether the changes are in excess of or lesser than the amount currently reflected in utility rates. Dr. Overcast argues that a symmetrical FAC design is not appropriate for Empire. Are there any other parties to this proceeding who have recommended a similar symmetrical FAC design?

A. Yes. Dr. Overcast's client, Empire, has also sponsored a symmetrical FAC design, as Dr. Overcast admits in his rebuttal testimony at page 6. In this regard, it is not clear exactly why Dr. Overcast is again criticizing the Staff and other parties for incorporating features in their FAC proposals that are shared by his client's own proposed FAC. Ms. Mantle also is addressing Dr. Overcast's "symmetry" argument in her surrebuttal testimony.

Q. Does the Commission, in fact, allow the utilities that it regulates recovery of all prudently incurred costs?

A. No. It is my understanding that certain of the disallowances proposed by the Staff and other parties, which are accepted by the Commission, are not held to be inappropriate for recovery because the expenditures are necessarily imprudent. Certain costs are disallowed by the Staff and other parties because they are of no benefit to ratepayers, not because they are imprudent. A utility may have the First Amendment right to advertise, but a utility does not have a First Amendment right to charge the costs of that advertising to ratepayers.

ROE AND RISK

Q. Dr. Overcast makes certain assertions as to the relative level of risk faced by Empire compared to other electric utilities in the section of his testimony entitled "ROE and Risk." Please comment on this section.

A. Dr. Overcast's point here is that the Staff's "comparable company" analysis conducted by Staff witness Matthew J. Barnes is made up entirely of utilities that either have full or partial fuel expense pass-through mechanisms in place. Dr. Overcast also alleges that many of these companies are afforded regulatory features by their commissions that allegedly provide them with more of an opportunity to earn their authorized rate of return, such as use of future test years. Dr. Overcast seems to be arguing that Empire should be granted a higher rate of return than the industry norm due to its allegedly higher level of risk.

Q. Do you agree with Dr. Overcast's conclusions?

A. No. Dr. Overcast's rebuttal testimony and schedules do not provide a fair or accurate depiction of Empire's level of risk compared to other utilities. In particular, Dr. Overcast entirely ignores the existence of the Regulatory Plan for Empire authorized in Case No. EO-2005-0263 and, specifically, the regulatory plan amortization (RPA) mechanism feature of that plan.

Q. Please describe the RPA mechanism.

A. The Stipulation and Agreement in Case No. EO-2005-0263 calls for Empire's revenue requirement to be determined in general rate cases through 2010 using two alternative methods. One method is by traditional rate base/rate of return regulation that has long been employed in Missouri, and the other method is through the RPA calculation. The RPA calculation is intended to measure whether Empire's cash flows under traditional rate methods will be sufficient to enable it the likelihood of maintaining its current investment grade credit rating status. To the extent that the RPA analysis shows that additional monies are needed in rates above and beyond the amount determined through traditional means in order to provide a reasonable opportunity to maintain Empire's current credit ratings, the Order adopting the Stipulation and Agreement in Case No. EO-2005-0263 requires those additional amounts be reflected in Empire's rates.

Q. Has Empire received additional amounts of rate relief in the past due to operation of the RPA mechanism?

A. Yes. In Empire's previous rate case, Case No. ER-2006-0315, the amount of rate relief granted to it was increased by over $10 million from the level that it would have received using traditional methods alone. In the current rate case, the Staff believes that it is likely that additional RPA revenues above the levels derived from traditional regulation will be necessary in this rate proceeding as well, though that amount is uncertain at this time.

Q. Does operation of the RPA mechanism serve to significantly reduce Empire's level of risk compared to other utilities that are not allowed such a feature?

A. The Staff asserts that it is obvious that it does.

Q. Is the Staff aware of other electric utilities that have mechanisms identical to or similar to the RPA in this or other jurisdictions?

A. Other than Kansas City Power & Light Company, a Missouri utility which also has an RPA mechanism in place, no.

Q. Why did Dr. Overcast ignore the RPA mechanism in his rebuttal testimony?

A. The Staff asked this question in Data Request No. 282. The Company's response to this data request can be found in Schedule 1.

Q. What does Schedule 1 show?

A. The Company response to Staff Data Request No. 282 shows that Empire and Dr. Overcast chose to ignore the operation of the RPA mechanism because they believe other regulatory mechanisms used in other states are more "favorable" and because they assert the RPA is not designed to allow Empire more of an opportunity to earn its authorized return on equity (ROE). This last point is apparently due to the fact that Empire must reflect an expense on its books equal to the amount of RPA rate collections it receives, so that the RPA will not affect Empire's ongoing reported earnings levels, all other things being equal.

Q. Does the Staff agree with this viewpoint?

A. No. Empire and Dr. Overcast go to some trouble to depict the Missouri regulatory climate as more risky than others, an opinion that ultimately can only be based upon a belief that Missouri is likely to grant less rate relief to its utilities because of its traditional regulatory practices than other jurisdictions are likely to grant their utilities. Then, when the Missouri Commission approves a regulatory mechanism that may grant Empire significantly higher levels of rate relief than would be afforded it under traditional regulatory practices in this state or other jurisdictions, such a mechanism is deemed "irrelevant" to Empire's relative risk level. This argument is neither consistent nor logical.

Q. Does the operation of the RPA mechanism for Empire serve to offset some of the risk that Empire attributes to the Missouri Commission's allegedly more stringent test year practices?

A. Yes. At page 15 of his rebuttal testimony, Dr. Overcast unfavorably compares Empire to other utilities in regard to Missouri's test year policies. Because the RPA has the effect of reflecting certain costs in Missouri customer rate levels prior to the point at which they would be reflected under traditional rate regulation, the existence of the RPA to some degree directly offsets any concerns or risk regarding the timing of inclusion in costs in rates via Missouri's standard test year and true-up policies. For this reason, Dr. Overcast's analysis and conclusions regarding Empire and its relative risk levels compared to other utilities is based upon an incomplete and biased analysis, and should be disregarded by the Commission.

Q. Are other Staff witnesses addressing Empire's position on this case concerning ROE?

A. Yes. Staff witness Barnes will be addressing the Company's rebuttal testimony concerning ROE in his surrebuttal testimony.

ASBURY SCR PROJECT

Q. What is the position of the Company regarding inclusion in rate base in this proceeding of its Asbury SCR plant addition?

A. As expressed in the rebuttal testimony of Empire witness Mertens, the Company believes the Asbury SCR addition should be included in its rate base because he asserts the project is currently complete and in-service. He argues that the in-service criteria previously agreed to for the Asbury SCR project calls for the inclusion of this project in rate base in this proceeding. Mr. Mertens further asserts that that the Company's position of only seeking the costs of the project expended and recorded on its books through December 31, 2007 meets the test year update cut-off for inclusion of costs in this case earlier set by the Commission.

Q. Does the Staff agree that the Asbury SCR project met its in-service criteria as of February 29, 2008, as stated by Mr. Mertens in his rebuttal testimony?

A. Yes, it does. Please refer to the surrebuttal testimony of Staff witness Michael E. Taylor for further discussion of this point.

Q. Does the fact that the Asbury SCR project is currently in-service mean the addition should be included in Empire's rate base in this case?

A. No, it does not. For a major plant addition, meeting the in-service criteria is a necessary but not sufficient condition for inclusion in rate base. Once having successfully met the in-service criteria, the plant addition in question should also be properly matched in time with other elements of the utility's revenue requirement (revenues, expenses, rate of return and capital structure) before being incorporated into a utility's revenue requirement. This matching in time is accomplished by establishing and enforcing a suitable cut-off for inclusion of utility costs in rates. This cut-off is normally either the end of the test year update period for a case, or the end of the true-up period for a case in those instances in which a true-up has been ordered by the Commission. In this case, the Commission has established a cut-off of December 31, 2007, the end of the test year update period, as the deadline for known and measurable incurred costs to be included in Empire's revenue requirement determination. The Asbury SCR project was not in-service as of that date.

Q. Doesn't the in-service criteria for the Asbury SCR project state that some of the criteria will be examined for successful completion by the Staff in its direct, rebuttal, or surrebuttal testimony, as the case may be?

A. Yes, it does. However, at the time these criteria were developed and agreed to, it was not known what the timing of the rate case would be in which Empire would seek inclusion of Asbury SCR costs in its rates. More specifically, it was not known what the ordered test year and test year update periods would be in that case, and whether a true-up audit was to be allowed in that proceeding. For example, if a true-up had been ordered in this proceeding, then the Asbury SCR project becoming in-service at the time of the Staff's surrebuttal testimony or even later might have been relevant for a rate determination for Empire in the instant case. But no true-up in this proceeding has been ordered. In any case, in entering into agreements concerning appropriate in-service criteria for plant additions, the Staff has never intended and does not intend in this case to allow those criteria to somehow trump the test year and test year update periods and other case deadlines ordered by the Commission that are intended to allow the inclusion of costs in rates for a utility in a matched and balanced fashion.

Q. Does Empire meet the December 31, 2007 cut-off period in this case by limiting its rate request to only those Asbury SCR costs incurred and booked by Empire at year-end 2007, as alleged by Mr. Mertens at page 5 of his rebuttal testimony?

A. No. All of the dollars spent by Empire and recorded on its books as of year-end 2007 were included in its Construction Work in Progress (CWIP) account, Account 107. By statute in this State, dollars in the CWIP account are not included in electric utility rate base, and are only eligible for inclusion in rate base when the underlying assets are in-service and the dollars have been transferred to the Plant in Service account. As stated by Mr. Mertens in his rebuttal testimony, and verified by Staff witness Taylor in his surrebuttal testimony, the Asbury SCR project was not in-service until February 29, 2008, and no amounts booked by Empire in relation to this project to Account 107 should have been transferred to its Plant in Service accounts before that date. The fact that Empire had accumulated some of the cost of the Asbury SCR project in its CWIP account as of year-end 2007, the end of the test year update period for the case, does not in any way make those costs eligible for inclusion in rates in this proceeding.

Q. What is the Staff's position on inclusion of the Asbury SCR project in rate base in this case?

A. It is the same as stated in the Staff's Cost of Service Report and in my rebuttal testimony. The Asbury SCR addition should not be included in this case because it was not in-service as of the test year update cut-off established by the Commission. This cut-off date was agreed to by all of the parties to this proceeding, including Empire.

Q. In the event the Commission agrees with Empire that the Asbury SCR project should be considered for inclusion in rates in this case, by what means should this be done?

A. As previously stated in my rebuttal testimony, if the Commission were to agree to Empire's arguments for including the Asbury SCR project in rate base in this case over the Staff's opposition, the Asbury SCR addition should only be reflected in rates in this proceeding through ordering of a true-up procedure to update all major elements of Empire's revenue requirement to allow for an appropriate matching of all elements of Empire's revenue requirement. Any such true-up should provide for an update to Empire's revenue requirement through either February or March, 2008.

DEPRECIATION

Q. What aspect of Empire witness Roff's rebuttal testimony are you addressing?

A. At pages 6-7 of his rebuttal testimony, Mr. Roff attacks the Staff's position that changes to Empire's depreciation rates are unnecessary during the duration of the Company's regulatory plan due to the existence of the regulatory plan amortization (RPA) mechanism.

Q. At page 7 of his rebuttal, Mr. Roff states that "the regulatory plan amortization is not related to the appropriate depreciation rates and that "there is no reason not to accept the results of my depreciation study simply because the regulatory plan amortization tool exists." Do you agree?

A. No. The Staff asserts that ordering new depreciation rates in this case will have a direct and material effect on the amount of RPA Empire would otherwise recover in rates. This is because the RPA calculations are directly based upon Empire's Funds from Operations (FFO) amounts. (FFO is a measurement of cash flow.) The amount of depreciation expense allowed in rates, because it is not associated with a specific cash outlay, is considered to increase a company's cash flow, and hence will increase a utility's FFO and decrease its RPA allowance, all other things being equal.

Q. Please explain further the relationship between depreciation expense, cash flow and the RPA.

A. If Empire is shown to have a deficiency in FFO under current customer rates, then the RPA agreement in the Stipulation and Agreement from Case No. EO-2005-0263 provides for rate recovery of an RPA sufficient to restore Empire's FFO to levels supportive of an investment grade credit rating. Under these circumstances, if the Commission were to grant Empire an increase in its depreciation rates, then such an increase would directly increase Empire's FFO and reduce the amount of RPA that Empire would otherwise require to maintain its current investment grade credit ratings. Any increase in depreciation expense will have a dollar-for-dollar impact of reducing Empire's calculated RPA. Therefore, as long as Empire is experiencing a shortage in FFO sufficient to trigger an RPA in this proceeding, it will make no difference to Empire's overall revenue requirement whether Empire's current depreciation rates are maintained or changed in this case.

Q. Is Empire currently experiencing a shortage in FFO sufficient to trigger an RPA in this proceeding?

A. Yes, according to the Staff's current revenue requirement recommendations.

Q. If changing Empire's depreciation rates will not change its overall revenue requirement in this case, why does the Staff oppose Empire's proposal to change its depreciation rates?

A. First, because the Commission itself suggested a policy of not changing depreciation rates during the duration of a regulatory plan highly similar to Empire's in its Order in Case No. ER-2006-0314, Kansas City Power and Light Company. Second, approving Empire's request to change its depreciation rates would officially authorize its proposed rates and methodologies. As pointed out in the rebuttal testimony of Staff witness Rosella L. Schad, the Staff believes there are significant deficiencies in how Empire is currently following the Commission's rules governing Empire's recording of supporting documentation necessary to properly calculate depreciation expense accruals. As discussed by Ms. Schad, the Staff believes there should be no changes to Empire's current depreciation rates until Empire significantly improves its adherence to Commission rules regarding depreciation recording practices.

REGULATORY PLAN AMORTIZATIONS

Q. What aspects of the rebuttal testimony of Empire witness Sager are you responding to?

A. I will respond to Mr. Sager's comments on the current status of the RPA issue in this case, particularly relating to an issue raised in the direct testimony of Industrial Intervener witness Michael Gorman.

Q. Do you agree with Mr. Sager's contention that there is agreement between Empire, the Staff and OPC concerning the format and appropriate calculation of Empire's RPA?

A. Yes, as discussed in my rebuttal testimony. However, that agreement does not necessarily extend to the issue raised by Mr. Gorman.

Q. What is the issue raised by the Industrial Interveners in Mr. Gorman's direct testimony?

A. Mr. Gorman alleges that the RPA calculation should reflect an adjustment for imputed depreciation related to Empire's purchased power agreements (PPAs).

Q. Why didn't you address Mr. Gorman's contentions in your rebuttal testimony?

A. I did not address the merits of the issue raised by Mr. Gorman in my rebuttal testimony because the Industrial Interveners, due to an oversight, did not provide documentary support for their position until after rebuttal testimony was filed.

Q. Having reviewed the documentation provided by Mr. Gorman, what does the Staff believe regarding the position taken by the Industrial Interveners concerning PPA depreciation?

A. The Staff believes there is substantial merit in the position taken by the Industrial Interveners on this matter.

Q. Please explain the issue raised by Mr. Gorman in more detail.

A. The RPA calculation is based in part on a quantification of the value of Empire's Off-Balance Sheet Obligations (OBSOs). OBSOs are items which the utilities treat as an item of expense on their financial statements, such as operating lease payments and PPA payments, but which credit rating agencies treat as the equivalent of capital assets for purposes of their credit rating analysis. As part of their OBSO analysis, the credit rating agencies will impute debt and interest costs to the utility related to its OBSOs, which will decrease the company's FFO levels. They may also impute depreciation expense related to the OBSOs, which would have the offsetting impact of increasing FFO levels for the utility.

The current RPA calculation agreed to by Empire, the Staff and OPC includes imputed interest associated with Empire's OBSOs, both operating leases and PPAs. It also includes imputed depreciation associated with the Company's operating lease obligations, but not its PPAs. In his direct testimony, Mr. Gorman argues that Standard & Poors' (S&P) incorporates imputed depreciation expense on PPAs in its current credit analysis of electric utilities, and that the Empire RPA calculation should include this adjustment as well.

Q. Do you agree with Mr. Gorman's assertions regarding S&P?

A. After reviewing the information supplied by Mr. Gorman on this matter, in conjunction with other S&P materials provided by Empire and by other members of the Commission Staff, I agree that S&P appears to have changed no later than the spring of 2007 to a credit ratings methodology which incorporated a PPA depreciation imputation adjustment into its FFO analysis of electric utilities. I have attached a copy of the S&P Report provided by Mr. Gorman entitled "Standard & Poors' Methodology for Imputing Debt for U.S. Utilities' Power Purchase Agreements" as Schedule 2 to this testimony. Schedule 2-2 contains a description of how S&P calculates the depreciation imputation adjustment.

Q. In his surrebuttal testimony, Mr. Sager argues against the Industrial Interveners' position on PPA depreciation imputation by stating that it is impossible at this point to determine exactly how S&P's PPA depreciation imputation for Empire would be calculated. Do you agree with Empire on this point?

A. Yes, but only in the sense that the parties to this proceeding do not have any exact knowledge of any aspect of S&P's specific analysis of Empire. Notwithstanding that fact, the Staff believes the evidence is clear that S&P does incorporate a depreciation imputation adjustment for PPAs in its electric utility analysis, and it has also provided a clear description of how this adjustment is calculated. For this reason, the Staff believes it is appropriate to include this adjustment in the RPA calculation for this proceeding, based upon our best knowledge and belief as to how this adjustment is calculated and evaluated by S&P.

Q. Does the Staff recommend that such an adjustment also be included in the RPA calculation for Empire in this case?

A. Yes. To the extent interest expense is imputed in Empire's RPA calculation for its PPAs, then depreciation expense should be imputed as well for the same PPAs.

Q. Is the proposed PPA depreciation imputation adjustment currently being discussed by the parties to this proceeding?

A. Yes. It is possible that a negotiated agreement on this matter can be reached. The parties are also discussing modifications to the amount of imputed debt associated with Empire's OBSOs to make these amounts consistent with a PPA depreciation imputation adjustment, and a change in the assumed interest rate to be applied to the OBSOs to determine the imputed interest associated with these items.

Q. Pending that possible outcome, what is the Staff's recommendation concerning the RPA at this time?

A. The Staff recommends that a PPA depreciation adjustment be included in Empire's RPA calculation in the amount of $5,378,172. Further, Empire's PPA debt equivalent amount should be restated to $58,510,167 in the RPA calculation. The interest rate to be applied to Empire's OBSO debt equivalent amounts should be restated to 6.8% in the calculation. These changes will result in a revised RPA amount of $2,910,077, to be added to the Staff's revenue requirement determined through traditional means.

COMMISSION RULES TRACKER/VEGETATION MANAGEMENT

Q. In his rebuttal testimony, Empire witness Keith states that the Company is willing to work with the Staff on a "tracker" mechanism similar to one already in place for AmerenUE for Empire's costs to comply with new Commission rules relating to vegetation management and infrastructure inspections Has the Staff previously indicated how such a tracker might work?

A. Yes, I proposed a general outline of a tracker mechanism in my rebuttal testimony.

Q. Do you have any changes to that proposal at this time?

A. Yes. In my rebuttal testimony, I suggested an incremental cost amount for Empire for compliance with the new Commission rules of $5.5 million (total Company) that would be appropriate for inclusion in rates in this case. I have since learned that I misinterpreted the data supplied by the Company that formed the basis of this initial estimate. New information from Empire indicates that an incremental cost of $2.68 million ($2.42 million Missouri jurisdictional) is a more accurate estimate of the Company's first year cost for compliance with the vegetation management and infrastructure inspection rules, with an estimated compliance cost of approximately $3 million for the second year ($2.735 million Missouri jurisdictional). When combined with Empire's current tree trimming costs as adjusted by the Staff in this case, this means that the total first year cost for tree trimming and rule compliance will be approximately $9.3 million ($8.4 million Missouri jurisdictional).

Given this new information, and the fact that rates from this proceeding are likely to be in effect for approximately two years, until the required Iatan II case is filed in 2010, the Staff now recommends that the average of Empire's first-year and second-year costs for compliance with the new rules be included in rates from this case in addition to its adjusted test year level of tree trimming costs. The amount of additional recovery would be $2.575 million annually, the average of the first and second year compliance costs when allocated to the Missouri jurisdiction. Under the Staff's proposal, Empire would be required to spend a total of $8.4 million in Missouri for its tree trimming and infrastructure inspection activities in Year 1, and $8.725 in Year 2 for these activities. If Empire does not spend the required amount in each year, it must spend the shortfall in the next year with interest added. Under the Staff's proposal, no deferral of amounts expended by Empire over the rate allowance amount or the individual year requirements would be allowed.

Q. Why does the Staff prefer a tracker approach to these costs in this case as opposed to the deferral approach allowed under the Commission's pending vegetation management and infrastructure inspections rules?

A. First, the Staff expects the new Commission rules will be approved and published shortly, which will obligate Empire to incur significantly higher levels of tree trimming expenses than it does currently. While these rules would allow electric utilities such as Empire to defer these higher level of costs for potential recovery in its next rate case, the Staff believes the better approach is to allow Empire immediate rate recovery of these incremental expenses (with penalty provisions if Empire does not spend the amounts received in rates for their intended purpose). Second, the Staff believes that Empire taking immediate action to increase the scope of its tree trimming activities would be in the public interest, and that it should be provided the financial resources in this case to accomplish this.

Q. What if the Commission's new rules are not implemented, for any reason?

A. In the unlikely event the new Commission rules concerning vegetation management and infrastructure inspections are not implemented, the Staff would still recommend that its tracker proposal be ordered, on the conditions that Empire still fully comply with the technical requirements contained within the rule drafts and that it will expend any additional funding received in rates on a timely basis for its intended purpose.

Q. Does this conclude your surrebuttal testimony?

A. Yes, it does.

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of The Empire District Electric Company of Joplin, Missouri's Application for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Missouri Service Area of the Company	)))))	Case No. ER-2008-0093

AFFIDAVIT OF MARK L. OLIGSCHLAEGER

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Mark L. Oligschlaeger, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Surrebuttal Testimony in question and answer form, consisting of 24 pages to be presented in the above case; that the answers in the foregoing Surrebuttal Testimony were given by him; that he has knowledge of the matters set forth in such answers; and that such matters are true and correct to the best of his knowledge and belief.

Mark L. Oligschlaeger

Mark L. Oligschlaeger

Subscribed and sworn to before me this 25th day of April, 2008.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
County of Cole
My Commission Exp. 07/01/2008

D. Suzie Mankin

Notary Public

Oligschlaeger, Mark*

From: ACloven@empiredistrict.com
Sent: Friday, April 18, 2008 4:38 PM
To: Oligschlaeger, Mark*
Cc: ACloven@empiredistrict.com
Subject: Case No. ER-2008-0093 - Data Request No. 0282
Attachments: 0282.doc; Response - Apr 18 2008 4_38PM.html

Missouri Public Service Commission

Respond Data Request

Data Request No.	0282
Company Name	Empire District Electric Company, The-Investor(Electric)
Case/Tracking No.	ER-2008-0093
Date Requested	4/10/2008
Issue	Rate of Return - Other Rate of Return Issues
Requested From	Angela Cloven
Requested By	Mark Oligschlaeger
Brief Description	Effect of Regulatory Plan Amortizations on Company Risk
Description	Re Overcast Rebuttal Schedules HEO-1 through HEO-4: 1) Did Mr. Overcast analyze the effect of the current "regulatory plan" in effect in Missouri for Empire, and in particular the existence of the regulatory plan amortization mechanism, in assessing the overall regulatory risk of Empire compared to other comparable companies in Mr. Barnes or Mr. Gorman"s ROE analyses in this case? If yes, please provide all available materials documenting Mr. Overcast"s analysis of the RPA mechanism. If no, why did Mr. Overcast not analyze the RPA mechanism for this purpose? 2) Is Mr. Overcast aware of a program identical to or highly similar to the regulatory plan amortization mechanism being in effect for electric utilities in other jurisdictions besides Missouri? If yes, please provide the details and supporting documentation for these programs.
Response	Provided by Ed Overcast - See Attachment.
Objections	NA

The attached information provided to **Missouri Public Service Commission** Staff in response to the above data information request is accurate and complete, and contains no material misrepresentations or omissions, based upon present facts of which the undersigned has knowledge, information or belief. The undersigned agrees to immediately inform the **Missouri Public Service Commission** if, during the pendency of Case No. **ER-2008-0093** before the Commission, any matters are discovered which would materially affect the accuracy or completeness of the attached information. If these data are voluminous, please (1) identify the relevant documents and their location (2) make arrangements with requestor to have documents available for inspection in the **Empire District Electric Company, The-Investor(Electric)** office, or other location mutually agreeable. Where identification of a document is requested, briefly describe the document (e.g. book, letter, memorandum, report) and state the following information as applicable for the particular document: name, title number, author, date of publication and publisher, addresses, date written, and the name and address of the person(s) having possession of the document. As used in this data request the term "document(s)" includes publication of any format, workpapers, letters, memoranda, notes, reports, analyses, computer analyses, test results, studies or data, recordings, transcriptions and printed, typed or written materials of every kind in your possession, custody or control or within your knowledge. The pronoun "you" or "your" refers to **Empire District Electric Company, The-Investor(Electric)** and its employees, contractors, agents or others employed by or acting in its behalf.

Security : Public
Rationale : NA

Missouri Public Service Commission

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Due Date	4/17/2008

Response

Response provided by Ed Overcast

The existence of the regulatory plan was reviewed and discussed with Empire as part of the analysis of the risks associated with Empire's ability to finance its construction program. The information reviewed included documents related to the stipulation adopting the plan, analysts' reports, and the draft testimony of Mr. Sager relative to this issue. The regulatory plan does not reduce overall regulatory risk. The regulatory plan requires an offsetting liability for the cash flow received. Although this plan has positive features related to providing Empire cash flows with the potential to maintain Empire's ability to finance its share of the construction program other regulatory mechanisms are more favorable. For example the Iowa Utilities Board uses an incentive return for new plants that is typically higher than the return for existing rate base. Wisconsin permits inclusion of 50% of CWIP in rate base. The FERC permits an incentive return at the upper end and CWIP in rate base for critical transmission infrastructure projects. The use of CWIP in rate base represents a more favorable regulatory treatment. In addition, some commissions provide both a more favorable opportunity to earn the allowed return and returns at the upper end of the zone of reasonableness to support superior credit metrics for regulated utilities.

In discussing the risk issues, the testimony focuses on the issue of the reasonable opportunity to earn the allowed return. The cash flow permitted under the regulatory plan assumes that the allowed return is earned in calculating the level of amortization to maintain investment grade. If there is no reasonable opportunity to earn the allowed return or, as in this case, parties propose that Empire be denied recovery of prudently incurred fuel and purchased power costs, there is insufficient mitigation beyond the control of Empire and places the Company in a more difficult financial position.

The attached information provided to Missouri Public Service Commission Staff in response to the above data information request is accurate and complete, and contains no material misrepresentations or omissions, based upon present facts of which the undersigned has knowledge, information or belief. The undersigned agrees to immediately inform the Missouri Public Service Commission Staff if, during the pendency of Case No. ER-2008-0093 before the Commission, any matters are discovered which would materially affect the accuracy or completeness of the attached information.

If these data are voluminous, please (1) identify the relevant documents and their location (2) make arrangements with requestor to have documents available for inspection in the Empire District Electric Company, The-Investor(Electric) office, or other location mutually agreeable. Where identification of a document is requested, briefly describe the document (e.g. book, letter, memorandum, report) and state the following information as applicable for the particular document: name, title number, author, date of publication and publisher, addresses, date written, and the name and address of the person(s) having possession of the document. As used in this data request the term "document(s)" includes publication of any format, workpapers, letters, memoranda, notes, reports,analyses, computer analyses, test results, studies or data, recordings, transcriptions and printed, typed or written materials of every kind in your possession, custody or control or within your knowledge. The pronoun "you" or "your" refers to Empire District Electric Company, The-Investor(Electric) and its employees, contractors, agents or others employed by or acting in its behalf.

Ratings

Standard & Poor?s Methodology For Imputing Debt For U.S. Utilities? Power Purchase Agreements

Back

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Standard & Poor's Methodology For Imputing Debt For U.S. Utilities' Power Purchase Agreements

Primary Credit Analyst:
David Bodek, New York (1) 212-438-7969;
david_bodek@standardandpoors.com
Secondary Credit Analysts:
Richard W Cortright, Jr., New York (1) 212-438-7665;
richard_cortright@standardandpoors.com
Solomon B Samson, New York (1) 212-438-7653;
sol_samson@standardandpoors.com
Additional Contacts:
Arthur F Simonson, New York (1) 212-438-2094;
arthur_simonson@standardandpoors.com
Arleen Spangler, New York (1) 212-438-2098;
arleen_spangler@standardandpoors.com
Scott Taylor, New York (1) 212-438-2057;
scott_taylor@standardandpoors.com
John W Whitlock, New York (1) 212-438-7678;
john_whitlock@standardandpoors.com

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For many years, Standard & Poor's Ratings Services has viewed power supply agreements (PPA) in the U.S. utility sector as creating fixed, debt-like, financial obligations that represent substitutes for debt-financed capital investments in generation capacity. In a sense, a utility that has entered into a PPA has contracted with a supplier to make the financial investment on its behalf. Consequently, PPA fixed obligations, in the form of capacity payments, merit inclusion in a utility's financial metrics as though they are part of a utility's permanent capital structure and are incorporated in our assessment of a utility's creditworthiness.

We adjust utilities' financial metrics, incorporating PPA fixed obligations, so that we can compare companies that finance and build generation capacity and those that purchase capacity to satisfy customer needs. The analytical goal of our financial adjustments for PPAs is to reflect fixed obligations in a way that depicts the credit exposure that is added by PPAs. That said, PPAs also benefit utilities that enter into contracts with suppliers because PPAs will typically shift various risks to the suppliers, such as construction risk and most of the operating risk. PPAs can also provide utilities with asset diversity that might not have been achievable through self-build. The principal risk borne by a utility that relies on PPAs is the recovery of the financial obligation in rates.

The Mechanics Of PPA Debt Imputation

A starting point for calculating the debt to be imputed for PPA-related fixed obligations can be found among the "commitments and contingencies" in the notes to a utility's financial statements. We calculate a net present value (NPV) of the stream of the outstanding contracts' capacity payments reported in the financial statements as the foundation of our financial adjustments.

The notes to the financial statements enumerate capacity payments for the five years succeeding the annual report and a "thereafter" period. While we have access to proprietary forecasts that show the detail underlying the costs that are amalgamated beyond the five-year horizon, others, for purposes of calculating an NPV, can divide the amount reported as "thereafter" by the average of the capacity payments in the preceding five years to derive an approximate tenor of the amounts combined as the sum of the obligations beyond the fifth year.

In calculating debt equivalents, we also include new contracts that will commence during the forecast period. Such contracts aren't reflected in the notes to the financial statements, but relevant information regarding these contracts are provided to us on a confidential basis. If a contract has been executed but the energy will not flow until some later period, we won't impute debt for that contract until the year that energy deliveries begin under the contract if the contract represents incremental capacity. However, to the extent that the contract will simply replace an expiring contract, we will impute debt as though the future contract is a continuation of the existing contract.

We calculate the NPV of capacity payments using a discount rate equivalent to the company's average cost of debt, net of securitization debt. Once we arrive at the NPV, we apply a risk factor, as is discussed below, to reflect the benefits of regulatory or legislative cost recovery mechanisms.

Balance sheet debt is increased by the risk-factor-adjusted NPV of the stream of capacity payments. We derive an adjusted debt-to-capitalization ratio by adding the adjusted NPV to both the numerator and the denominator of that ratio.

We calculate an implied interest expense for the imputed debt by multiplying the same utility average cost of debt used as the discount rate in the NPV calculation by the amount of imputed debt. The adjusted FFO-to-interest expense ratio is calculated by adding the implied interest expense to both the numerator and denominator of the equation. We also add implied depreciation to the equation's numerator. We calculate the adjusted FFO-to-total-debt ratio by adding imputed debt to the equation's denominator and an implied depreciation expense to its numerator.

Our adjusted cash flow credit metrics include a depreciation expense adjustment to FFO. This adjustment represents a vehicle for capturing the ownership-like attributes of the contracted asset and tempers the effects of imputation on the cash flow ratios. We derive the depreciation expense adjustment by multiplying the relevant year's capacity payment obligation by the risk factor and then subtracting the implied PPA-related interest expense for that year from the product of the risk factor times the scheduled capacity payment.

↑ back to top

Risk Factors

The NPVs that Standard & Poor's calculates to adjust reported financial metrics to capture PPA capacity payments are multiplied by risk factors. These risk factors typically range between 0% to 50%, but can be as high as 100%. Risk factors are inversely related to the strength and availability of regulatory or legislative vehicles for the recovery of the capacity costs associated with power supply arrangements. The strongest recovery mechanisms translate into the smallest risk factors. A 100% risk factor would signify that all risk related to contractual obligations rests on the company with no mitigating regulatory or legislative support.

For example, an unregulated energy company that has entered into a tolling arrangement with a third-party supplier would be assigned a 100% risk factor. Conversely, a 0% risk factor indicates that the burden of the contractual payments rests solely with ratepayers. This type of arrangement is frequently found among regulated utilities that act as conduits for the delivery of a third party's electricity and essentially deliver power, collect charges, and remit revenues to the suppliers. These utilities have typically been directed to sell all their generation assets, are barred from developing new generation assets, and the power supplied to their customers is sourced through a state auction or third parties, leaving the utilities to act as intermediaries between retail customers and the electricity suppliers.

Intermediate degrees of recovery risk are presented by a number of regulatory and legislative mechanisms. For example, some regulators use a utility's rate case to establish base rates that provide for the recovery of the fixed costs created by PPAs. Although we see this type of mechanism as generally supportive of credit quality, the fact remains that the utility will need to litigate the right to recover costs and the prudence of PPA capacity payments in successive rate cases to ensure ongoing recovery of its fixed costs. For such a PPA, we employ a 50% risk factor. In cases where a regulator has established a power cost adjustment mechanism that recovers all prudent PPA costs, we employ a risk factor of 25% because the recovery hurdle is lower than it is for a utility that must litigate time and again its right to recover costs.

We recognize that there are certain jurisdictions that have true-up mechanisms that are more favorable and frequent than the review of base rates, but still don't amount to pure pass-through mechanisms. Some of these mechanisms are triggered when certain financial thresholds are met or after prescribed periods of time have passed. In these instances, in calculating adjusted ratios, we will employ a risk factor between the revised 25% risk factors for utilities with power cost adjustment mechanisms and 50%.

Finally, we view legislatively created cost recovery mechanisms as longer lasting and more resilient to change than regulatory cost recovery vehicles. Consequently, such mechanisms lead to risk factors between 0% and 15%, depending on the legislative provisions for cost recovery and the supply function borne by the utility. Legislative guarantees of complete and timely recovery of costs are particularly important to achieving the lowest risk factors.

↑back to top

Illustration Of The PPA Adjustment Methodology

The calculations of the debt equivalents, implied interest expense, depreciation expense, and adjusted financial metrics, using risk factors, are illustrated in the following example:

Example Of Power-Purchase Agreement Adjustment

($000s)	Assumption	Year 1	Year 2	Year 3	Year 4	Year 5	Thereafter
Cash from operations	2,000,000						
Funds from operations	1,500,000						
Interest expense	444,000						
Directly issued debt							
Short-term debt	600,000						
Long-term due within one year	300,000						
Long-term debt	6,500,000						
Shareholder's Equity	6,000,000						
Fixed capacity commitments	600,000	600,000	600,000	600,000	600,000	600,000	4,200,000*
NPV of fixed capacity commitments							
Using a 6.0% discount rate	5,030,306						
Application of an assumed 25% risk factor	1,257,577						
Implied interest expense¶	75,455						
Implied depreciation expense	74,545						
Unadjusted ratios							
FFO to interest (x)	4.4						
FFO to total Debt (%)	20.0						
Debt to capitalization (%)	55.0						

Ratios adjusted for debt imputation	
FFO to interest (x)§	4.0
FFO to total debt (%)**	18.0
Debt to capitalization (%)¶¶	59.0

*Thereafter approximate years: 7. ¶The current year's implied interest is subtracted from the product of the risk factor multiplied by the current year's capacity payment. §Adds implied interest to the numerator and denominator and adds implied depreciation to FFO. **Adds implied depreciation expense to FFO and implied debt to reported debt. ¶¶Adds implied debt to both the numerator and the denominator. FFO--Funds from operations. NPV--Net present value.

↑back to top

Short-Term Contracts

Standard & Poor's has abandoned its historical practice of not imputing debt for contracts with terms of three years or less. However, we understand that there are some utilities that use short-term PPAs of approximately one year or less as gap fillers pending the construction of new capacity. To the extent that such short-term supply arrangements represent a nominal percentage of demand and serve the purposes described above, we will neither impute debt for such contracts nor provide evergreen treatment to such contracts.

↑back to top

Evergreen Treatment

The NPV of the fixed obligations associated with a portfolio of short-term or intermediate-term contracts can lead to distortions in a utility's financial profile relative to the NPV of the fixed obligations of a utility with a portfolio of PPAs that is made up of longer-term commitments. Where there is the potential for such distortions, rating committees will consider evergreen treatment of existing PPA obligations as a scenario for inclusion in the rating analysis. Evergreen treatment extends the tenor of short- and intermediate-term contracts to reflect the long-term obligation of electric utilities to meet their customers' demand for electricity.

While we have concluded that there is a limited pool of utilities whose portfolios of existing and projected PPAs don't meaningfully correspond to long-term load serving obligations, we will nevertheless apply evergreen treatment in those cases where the portfolio of existing and projected PPAs is inconsistent with long-term load-serving obligations. A blanket application of evergreen treatment is not warranted.

To provide evergreen treatment, Standard & Poor's starts by looking at the tenor of outstanding PPAs. Others can look to the "commitments and contingencies" in the notes to a utility's financial statements to derive an approximate tenor of the contracts. If we conclude that the duration of PPAs is short relative to our targeted tenor, we would then add capacity payments until the targeted tenor is achieved. Based on our analysis of several companies, we have determined that the evergreen extension of the tenor of existing contracts and anticipated contracts should extend contracts to a common length of about 12 years.

The price for the capacity that we add will be derived from new peaker entry economics. We use empirical data to establish the cost of developing new peaking capacity and reflect regional differences in our analysis. The cost of new capacity is translated into a dollars per kilowatt-year (kW-year) figure using a weighted average cost of capital for the utility and a proxy capital recovery period.

↑back to top

Analytical Treatment Of Contracts With All-In Energy Prices

The pricing for some PPA contracts is stated as a single, all-in energy price. Standard & Poor's considers an implied capacity price that funds the recovery of the supplier's capital investment to be subsumed within the all-in energy price. Consequently, we use a proxy capacity charge, stated in $/kW, to calculate an implied capacity payment associated with the PPA. The $/kW figure is multiplied by the number of kilowatts under contract. In cases of resources such as wind power that exhibit very low capacity factors, we will adjust the kilowatts under contract to reflect the anticipated capacity factor that the resource is expected to achieve.

We derive the proxy cost of capacity using empirical data evidencing the cost of developing new peaking capacity. We will reflect regional differences in our analysis. The cost of new capacity is translated into a $/kW figure using a weighted average cost of capital and a proxy capital recovery period. This number will be updated from time to time to reflect prevailing costs for the development and financing of the marginal unit, a combustion turbine.

↑back to top

Transmission Arrangements

In recent years, some utilities have entered into long-term transmission contracts in lieu of building generation. In some cases, these contracts provide access to specific power plants, while other transmission arrangements provide access to competitive wholesale electricity markets. We have concluded that these types of transmission arrangements represent extensions of the power plants to which they are connected or the markets that they serve. Irrespective of whether these transmission lines are integral to the delivery of power from a specific plant or are conduits to wholesale markets, we view these arrangements as exhibiting very strong parallels to PPAs as a substitute for investment in power plants. Consequently, we will impute debt for the fixed costs associated with long-term transmission contracts.

↑back to top

PPAs Treated As Leases

Several utilities have reported that their accountants dictate that certain PPAs need to be treated as leases for accounting purposes due to the tenor of the PPA or the residual value of the asset upon the PPA's expiration. We have consistently taken the position that companies should identify those capacity charges that are subject to operating lease treatment in the financial statements so that we can accord PPA treatment to those obligations, in lieu of lease treatment. That is, PPAs that receive operating lease treatment for accounting purposes won't be subject to a 100% risk factor for analytical purposes as though they were leases. Rather, the NPV of the stream of capacity payments associated with these PPAs will be reduced by the risk factor that is applied to the utility's other PPA commitments. PPAs that are treated as capital leases for accounting purposes will not receive PPA treatment because capital lease treatment indicates that the plant under contract economically "belongs" to the utility.

↑back to top

Evaluating The Effect Of PPAs

Though history is on the side of full cost recovery, PPAs nevertheless add financial obligations that heighten financial risk. Yet, we apply risk factors that reduce debt imputation to recognize that utilities that rely on PPAs transfer significant risks to ratepayers and suppliers.

↑back to top