STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-7, SUB 1276

In the Matter of Application of Duke Energy Progress, LLC, for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina and for Performance-Based Regulation	)))))	CUCA'S POST-HEARING BRIEF

Carolina Utility Customers Association, Inc. ("CUCA"), through counsel, hereby respectfully submits this Post-Hearing Brief regarding the Rate Case Application and Request for Performance Based Regulation filed by Duke Energy Carolinas, LLC (the "Company," "Duke," or "DEC").[1]

INTRODUCTION

DEC's request for an increase in its rates and approval of its performance-based regulation ("PBR") application highlights the tensions created by the various, and often opposing, state policy goals set forth and embodied in Chapter 62 of the North Carolina General Statutes. The Commission's task of simultaneously achieving "fair regulation," "adequate, reliable, and economical utility service," and "just and reasonable rates," along with the other stated goals, requires balancing of various competing factors towards an overall goal of promoting the public interest.[2]

With the passage of Session Law 2021-165 (HB 951), DEC obtained the ability to seek performance-based regulation, including a multi-year rate plan, which it seeks in this

[1] This brief does not address all issues arising in this proceeding. CUCA's silence on any issue should not be construed as acquiescence to any particular position.

[2] N.C.G.S. § 62-2.(a)(1), (3), (4).

case. As only the second attempt to implement HB 951, this case presents a number of legal and factual issues that are of critical importance to the future of our State.

As discussed below,

- DEC has failed to support its request for a return on equity of 10.4%, Rather, the evidence supports an ROE at or substantially below 9.8%.
- DEC has similarly failed to justify its requested capital structure of 53% equity and 47% debt. The record evidence shows that the equity ratio should be no higher than 52%.
- The record shows that many of the MYRP "projects" offered by DEC to be incorporated in the MYRP are not, in fact, "discrete and identifiable" capital spending projects that are allowed to be included in an MYRP.
- The record shows that DEC has presented many MYRP projects with ostensible O&M savings, but has failed to calculate the net savings of these projects (which would otherwise be credited to ratepayers). These projects should be excluded from any approved MYRP.
- The record does not support a conclusion that the proposed MYRP minimizes interclass subsidies to the greatest extent practicable, and therefore it should be rejected.
- DEC has failed to show that its GIP spending on self-optimizing grid has achieved the reliability benefits that were a substantial basis for the Commission's approval of deferral accounting for this project. Accordingly, DEC has failed to carry its burden to show that the nearly $400 million it

spent on this program was prudently incurred, and recovery of these costs should be rejected.

- Several aspects of DEC's industrial rate designs could be altered to provide the correct incentives for industrial customers to reduce their energy use.
- The proposed Reliability PIM fails to provide incentive for DEC to improve its system reliability performance. A significantly larger, continuously increasing penalty will provide a true incentive for DEC to reverse its trend of declining system performance.

SUMMARY OF CUCA-SPONSORED TESTIMONY

CUCA presented the testimony of Jeffry Pollock, President of J. Pollock, Inc.; Billie S. LaConte, an Associate Consultant at J. Pollock, Inc.; and David Lyons, the Director of Energy for Gerdau, N.A.

Witness Pollock's testimony addressed DEC's proposed MYRP, along with class revenue allocation and rate design issues. Witness Pollock testified concerning DEC's failure to establish a clear connection between its MYRP projects and the need to reduce carbon emissions. Witness Pollock pointed out that DEC's proposal to calculate MYRP rates using its 2021 billing determinants will result in more than $200 million in surplus revenues compared to the use of updated billing determinants for each year of the MYRP. Witness Pollock recommended the Commission require DEC file enhanced earnings reports so that the earnings sharing mechanism in HB 951 can be adequately implemented. Witness Pollock also proposed a rate competitiveness Performance Incentive Mechanism ("PIM") to reward or penalize DEC based on its rates vis-à-vis other regional utilities. He further shows that DEC has failed to reduce interclass subsidies to the "greatest extent practicable," as required by law. Witness Pollock also made practical recommendations to improve the rate tariffs for DEC's time-of-use ("TOU") and Schedule HP tariffs, including longer duration peak periods, elimination of DEC's proposed increase to the HP tariff Incentive Margin that has no evidentiary basis, and rejection of DEC's proposal to reset its measurement of customer baseline load ("CBL") every four years. Finally, witness Pollock recommended the Commission require DEC's proposed Customer Assistance Program ("CAP") to be funded solely by the Residential Class to further the goal of eliminating interclass subsidies.

CUCA witness LaConte opined on DEC's proposed return on equity, capital structure, and PIMs. Witness LaConte concluded that DEC witness Morin's recommended return on equity ("ROE") of 10.4% was overstated. Based on her own analysis of ROE using several accepted methods, including the Discounted Cash Flow ("DCF") model, Capital Asset Pricing Model ("CAPM"), and Risk Premium model, witness LaConte recommended an authorized ROE of 9.4% (absent approval of an MYRP) or 9.2% (if the MYRP is approved). Witness LaConte recommended a capital structure of 51.55% equity, based on the average capital structure of her proxy group of similar electric utilities. Finally, witness LaConte recommended rejecting DEC's proposed Peak Load Reduction and Renewables Integration and Encouragement PIMs, both of which would reward DEC for actions that it should be undertaking anyway in the course of prudent utility management.

CUCA witness Lyons offered testimony on his experience as the Director of Energy for Gerdau, N.A., particularly with regard to the effect of DEC's rates on Gerdau's Charlotte Steele Mill. The Charlotte Steel Mill is one of the largest recyclers in the state and produces some of the world's least carbon-intensive steel. The Mill currently employs approximately 230 people and supports even more jobs in the broader economy. Witness Lyons testified concerning the potential harm to Gerdau and the competitiveness of North Carolina resulting from the significant and compounding rate increases requested by DEC in the near future.

ARGUMENT

I. DEC HAS NOT JUSTIFIED ITS REQUESTED RETURN ON EQUITY AND PROPOSED CAPITAL STRUCTURE.

DEC is seeking an inappropriately high return on equity ("ROE") of 10.4%. As explained below, DEC's own submissions set a ceiling of 10.2% and provide no principled basis for exceeding the 9.8% ROE authorized in the recent DEP Order[3]. The testimony of the Public Staff witnesses, intervenor witnesses, and Duke's own expert witness indicates that the appropriate ROE is less than 9.8%. Duke is also seeking an excessive equity-to-debt capital structure without justification.

A. DEC's requested ROE is capped at 10.2%.

DEC witness Dr. Morin recommended an ROE of 10.4%.[4] However, Dr. Morin's conclusion included an increase of 20 basis points based upon Dr. Morin's belief that it would be appropriate to add an adjustment to account for flotation costs.[5] However, as the Commission recognized in its recent order in the DEP rate case, flotation costs may not be

[3] Order Accepting Stipulations, Granting Partial Rate Increase, and Requiring Public Notice, Docket No. E-2, Sub 1300 (Aug. 18, 2023) (hereinafter, "DEP Order").
[4] Tr. vol. 7, 255.
[5] Tr. vol. 7, 249-55.

included in rates where "there was and is no plan to issue equity."[6] As Dr. Morin conceded on cross-examination, DEC has no plans to issue equity before 2027 and Dr. Morin's ROE recommendations must be reduced by 20 basis points.[7] Accordingly, Dr. Morin's range of ROE estimates is 9.1% to 11.0%, with an average of 10.2%.[8] No witness in the case recommended an ROE of more than 10.2% (disregarding flotation costs). Accordingly, there is no evidentiary basis for the Commission to authorize an ROE of more than 10.2%.

B. The record does not support an ROE in excess of 9.8%.

In setting the allowed return on equity, the Commission should be mindful of "the twin goals of assuring sufficient shareholder investment in utilities while simultaneously maintaining the lowest possible cost to the using public for quality service."[9] Specifically, "the Commission's task is to set rates as low as possible consistent with the dictates of the United States and North Carolina Constitutions."[10]

Dr. Morin's direct testimony set the high-water mark for ROE recommendations in this case, but other expert witness testimony presented suggests that the authorized ROE should be substantially lower.

Public Staff witness Walters recommended an ROE of 9.35%, with a common equity ratio of 52.0%, from a range of ROE estimates of 9.20% to 9.90%.[11] CUCA witness

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[6] DEP Order, at 164-65.

[7] Tr. vol. 7, 395.

[8] Tr. vol. 7, 255 (adjusted to remove Dr. Morin's flotation cost adjustment).

[9] *State ex rel. Utilities Comm'n v. Carolina Util. Customers Ass'n, Inc.*, 348 N.C. 452, 458, 500 S.E.2d 693, 698 (1998).

[10] Order Granting General Rate Increase, Docket No. E-7, Sub 1026, at 25 (Sept. 24, 2013) (citing *State ex rel. Utils. Comm'n v. Pub. Staff-N.C. Utils. Comm'n*, 323 N.C. 481, 490, 374 S.E.2d 361, 370 (1988))

[11] Tr. vol. 14, 18-19.

LaConte recommended an ROE of 9.4% (in the absence of an MYRP) or 9.2% (if an MYRP is approved), from a range of ROE estimates of 8.99% to 10.03%.[12] On cross-examination, Dr. Morin indicated that the Commission should give weight to the CAPM calculation presented by CUCA witness LaConte, which, as corrected by Dr. Morin, would result in an ROE of 9.8%, which Dr. Morin considered to be a reasonable ROE estimate.[13] NCJC et al. expert witness Ellis testified concerning an alternative analytical framework and recommended, based on that framework, an ROE of 6.15%.[14]

In its order in the most recent DEP rate case, the Commission authorized an ROE of 9.8%.[15] Dr. Morin conceded on cross-examination that he is not aware of any substantive difference between DEC and DEP that would justify DEC having a different rate of return than that authorized for DEP.[16] The only basis for the difference in his recommendations for DEC and DEP is the change in the prevailing interest rates that occurred during the few months between the preparation of his testimony in each case.[17] However, Dr. Morin conceded on cross-examination that the authorized rate of return should not depend on changes in interest rates over the course of months.[18] Dr. Morin also conceded that interest rates are as likely to go down as they are to go up during the MYRP period, and that he would be unwilling to stake his own money on the presumption that rates will go up.[19] In

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[12] Tr. vol. 15, 634.
[13] Tr. vol. 7, 423-25.
[14] Tr. vol. 15, 687.
[15] DEP Order, at 157.
[16] Tr. vol. 7, 400.
[17] Tr. vol. 7, 196, 399.
[18] Tr. vol. 7, 401.
[19] Tr. vol. 7, 401.

sum, Dr. Morin's testimony identifies no substantive reason why the return on equity authorized in this case should exceed the 9.8% ROE approved in the DEP Order.

Furthermore, although Dr. Morin came up with a higher ROE recommendation, his testimony should not be given more weight than the testimony of Public Staff witness Walters or CUCA witness LaConte. In fact, witnesses Walters and LaConte independently arrived at very similar ROE ranges and recommendations, which topped out at 9.9% and 10.0%, respectively. Given Dr. Morin's concession that DEC should not have a higher authorized ROE than DEP, the record does not support an ROE in excess of the ranges indicated by witnesses Walters and LaConte. In fact, Dr. Morin's willingness to recommend an ROE that was 70 basis points lower than his own CAPM estimate[20] indicates that there is substantial evidence for authorizing an ROE substantially lower than the 9.8% that Dr. Morin considered to be a reasonable ROE estimate based on witness LaConte's proxy group.[21]

In the DEP Order, three dissenting Commissioners raised concerns about the 9.8% ROE approved in that case, including (1) whether the Commission believed it was constrained below 10.0%, (2) whether the DCF model produces erroneous results in an environment of rising interest rates, (3) whether a 9.8% return on equity will result in a credit downgrade, and (4) whether recent decisions to authorize 9.8% rates of return for water utilities indicates that electric utility ROEs should be higher. However, none of those contentions provide any reason to authorize a higher ROE in this case. As to whether the Commission believed there was some constraint requiring an ROE below 10.0%, there is

[20] Tr. vol. 7, 243.
[21] Tr. vol. 7, 423-25.

was no evidence of such a constraint in the DEP case and there is none in this case. Rather, the ROE testimony offered by the many witnesses in this case presented a range of ROE estimates both above and below 10.0%—just like in the DEP case. As to the DCF model, as recognized by the Commission in the DEP Order[22] and by DEC witness Morin[23] in this case, no single method of estimating ROE should be given preference over the others. No model perfectly projects the appropriate ROE for every utility in every context, which is why the Commission historically and appropriately has considered a variety of models and their respective results in identifying the appropriate ROE. Furthermore, with regard to rising interest rates, the evidence in this case is that interest rates have risen recently but there is also significant uncertainty about what will happen in the future. The Commission should reject the unfounded position that interest rates will remain high or trend higher than current levels and should not base the going-forward rate decision in this case on short-term economic fluctuations. As DEC witness Morin indicated, rates are as likely to go down as they are to go up over the next several years. As to whether a 9.8% ROE will result in a credit downgrade, there is no evidence that such a downgrade will occur for DEC and it is difficult to see how authorizing an increased ROE from the current level of 9.6% will result in a credit downgrade. As to the relevance of water utility rates of return on equity, the Commission has in front of it the ROE estimates of a number of witnesses, including DEC witness Morin, who recommends an ROE of 10.2% on behalf of DEC (excluding flotation costs), whereas other witnesses recommend a far lower rate of return.

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[22] DEP Order, p. 159 ("[I]t has been the Commission's long-standing practice to consider and place weight on multiple models in order to protect against any one model's skewing the outcome in times when it may be less indicative of the true cost of capital.").

[23] Tr. Vol. 8, pp. 209, 255.

Simply put, regardless of what happened in water utility cases, the evidence in this case supports a rate of return of 9.8% or lower.

Notably, the Commission must consider "any increased or decreased risk to either the electric public utility or its ratepayers that may result from having an approved MYRP."[24] The record is clear that, if an MYRP is approved, DEC's risks (including regulatory lag) will be less than they otherwise would be and less risky than many comparable electric utilities.[25] It would be reasonable for the Commission to select a lower authorized ROE in light of the lower risk to DEC's ability to earn the authorized return.

It bears repeating that the duty of this Commission is "to set rates as low as possible consistent with" constitutional limitations, not to provide DEC with greater returns than are lawfully required. The expert witness testimony presented in this case makes clear that the Commission can and therefore should authorize a rate of return on equity that is less than what was authorized in the DEP Order. DEC's attempt to cite rising interest rates as a reason to increase its allowed ROE fails to take into account that ratepayers are also facing higher interest rates. Moreover, as the testimony of CUCA witness Lyons highlights, North Carolina's businesses are facing increased pressure from rising electricity rates that may render the state uncompetitive.[26] The Commission has a duty to protect North Carolina's ratepayers. Because the evidence supports the authorization of an ROE below 9.8%, the law and policy of our state requires the Commission to do so.

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[24] N.C.G.S. § 62-133.16(c)(1)(a).
[25] *E.g.*, Tr. vol. 15, 638-39.
[26] Tr. vol. 5, 415-17.

C. The Commission should reject DEC's request for an unnecessarily high equity ratio.

DEC proposes that its rates be based on a capital structure comprised of 53% equity and 47% debt.[27] However, the record shows that DEC's capital structure should be set at a lower level of equity.

First, it should be recognized, consistent with the testimony of DEC's own expert witnesses, that the imputed capital structure authorized by the Commission for calculating the rate of return is not used by DEC as a fixed limit on its actual capital structure and that, in practice, its actual capital to debt structure is driven by business exigencies and not strict adherence to the rate formula.[28] Although it presumably could do so, the Commission does not generally require utilities to maintain the "approved" capital structure, either on a continuous basis or on average. For instance, in DEC's previous rate case, DEC's testimony indicated the Company would likely maintain a capital structure ranging from 52% to 53% capital and 48% to 47% debt through 2023. Nevertheless, the Commission authorized the 52%/48% capital structure stipulated by DEC, despite clear testimony that the actual capital structure would vary from the approved ratio; there was no expectation or requirement that DEC would actually maintain a 52/48 split. In fact, the record in this case reflects that DEC's capital structure has not even stayed within the *range* DEC

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[27] E.g., Tr. vol. 9, 62.

[28] Tr. vol. 14, 49-50 (discussing the Commission's use of an imputed capital structure); Tr. vol. 16, 25-27 (DEC witness Newlin recognizing that DEC requests the Commission use an imputed capital structure, rather than DEC's actual capital structure, to calculate rates).

anticipated in the previous rate case.[29] DEC's most recently reported capital structure is 51.14% equity and 48.86% debt for the period ending June 30, 2023.[30]

Here, DEC witness Newlin testified that DEC expects its equity ratio to fluctuate over time and plans to "manage its capital structure within a reasonable range" of 53% equity.[31] On cross-examination, witness Newlin conceded that DEC is not actually able to maintain a constant equity ratio, that DEC's rates are based on the approved capital structure, and that the revenues collected by the Company may not reflect the Company's actual capital structure at any given time.[32] More concretely, witness Newlin conceded that its revenues are, in effect, overcollecting whenever the actual capital structure of the Company varies downward from the approved equity ratio.[33] Conversely, the Company effectively lowers its achieved ROE if the equity ratio is allowed to exceed the level approved by the Commission. In other words, the Company has a direct financial incentive to seek establishment of rates based on an aggressive allocation of equity while maintaining its actual equity ratio as low as possible without affecting its ability to obtain credit. On cross-examination, witness Newlin conceded that DEC has such an incentive, but noted that "gamesmanship" relating to excessive debt would be harmful to the Company in the

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[29] Tr. vol. 9, 69 (reporting 53.1% equity at the end of 2021); Tr. vol. 14, 52 (reporting DEC's capital structure as of March 31, 2023, as 50.95% equity and 49.05% debt).

[30] Duke Energy Carolinas, LLC's Quarterly Surveillance Report E.S.-1 Docket No. M-1, Sub 12DEC (Aug. 31, 2023).

[31] Tr. vol. 9, 69.

[32] Tr. vol. 9, 82-84.

[33] Tr. vol. 9, 83-84.

long-term. However, witness Newlin also conceded that he would not consider 52% equity to be "gamesmanship" if the Commission authorizes a 53/47 split.[34]

Moreover, DEC expects to take on additional debt and to be cashflow-negative in the coming years to enable the Company to pursue its various capital spending programs.[35] DEC's planned capital investments will tend to drive DEC's actual equity ratio downward, even if DEC attempts to maintain 53% equity.

While DEC initially sought approval for a 53% equity ratio in its previous rate case, DEC has been able to maintain a stable credit rating[36] despite the 52% equity ratio authorized and significant investments (particularly in GIP programs) since that rate case.

Finally, witness Newlin's rebuttal testimony concedes that the average equity ratio approved in electric utility rate cases in 2023 has been 50.71%.[37]

The testimony of other witnesses supports a lower level of equity. Public Staff witness Walters recommends a 52/48 split, noting that the proposed 53/47 structure exceeds the equity ratio of his proxy group, DEC's actual capital structure as recently reported by the Company, and the equity ratios approved by the Commission in DEC's last two rate cases.[38] CUCA witness LaConte proposed a 51.55% equity ratio based on the average ratio of utilities in her proxy group.[39]

In sum, DEC will not maintain the 53/47 capital structure it requests in this case even if that structure is approved by the Commission; DEC's actual equity ratio can be

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[34] Tr. vol. 9, 84.
[35] Tr. vol. 9, 80-82.
[36] Tr. vol. 9, 80.
[37] Tr. vol. 16, 30.
[38] Tr. vol. 14, 49, 51-53.
[39] Tr. vol. 15, 658-59.

expected to face significant downward pressure because of the investments the Company plans to make; DEC will effectively overcollect revenues if its actual equity ratio is lower than the ratio approved; DEC has been able to maintain its credit rating despite significant investments since the last rate case, where a 52/48 capital structure was authorized; and similar utilities' authorized equity ratios average less than 51% in 2023.

The record evidence does not support DEC's requested capital structure. The Commission should authorize an equity ratio of no more than 52.0%.

II. DEC HAS NOT ESTABLISHED THAT THE CATEGORIES OF SPENDING IDENTIFIED AS MYRP "PROJECTS" ARE IN FACT "DISCRETE AND IDENTIFIABLE CAPITAL SPENDING PROJECTS TO BE PLACED IN SERVICE."

This is only the second proceeding in which the Commission has been called upon to apply the MYRP provisions of HB 951, and it is natural that there may be a certain "learning curve" in applying a new statutory scheme which authorized a limited departure from the Commission's historical rate setting methodology for specified expenditures. A careful examination of the language of the legislation shows that the General Assembly did not intend, in enacting HB 951, to authorize forward-looking rates based upon any and all money DEC might propose to spend during the MYRP. Rather, the legislature specified that:

> The base rates for the first rate year of a MYRP shall be fixed in the manner prescribed under G.S. 62-133, including actual changes in costs, revenues, or the cost of the electric public utility's property used and useful, or to be used and useful within a reasonable time after the test period, plus costs associated with a ***known and measurable set of capital investments***, net of operating benefits, associated with ***a set of discrete and identifiable capital spending projects to be placed in service during the first rate year***. Subsequent changes in base rates in the second and third rate years of the MYRP shall be based on projected incremental Commission-authorized ***capital investments that will be used and useful during the rate year*** and associated expenses, net of operating benefits, including operation and

> maintenance savings, and depreciation of rate base associated with the capital investments, that are incurred or realized during each rate year of the MYRP period[.][40]

That is, changes to rate base in the first year of an MYRP must reflect "capital investments" that (1) are "known and measurable," (2) are associated with "discrete and identifiable capital spending projects" and (3) will be "placed in service" during the rate year. Changes to rate base in the second and third years of an MYRP must be based on "Commission-authorized capital investments that will be used and useful during the rate year" and "associated expenses." Reading these provisions in *pari materia*, and considering the fact that the Commission cannot "authorize" a project that is not "discrete and identifiable," the "capital improvements" that can be included in rate base in MYRP Years 1, 2, and 3 are all subject to the same requirements: that they be (1) "known and measurable," (2) associated with "discrete and identifiable capital spending projects" and (3) "placed in service" during the relevant rate year.

An "investment" is an "expenditure to acquire property or assets to produce revenue."[41] An investment is "known and measurable" if DEC has documented what the

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[40] N.C.G.S. § 62-133.16(c)(1)(a) (emphases added).
[41] Investment, *Black's Law Dictionary* (11th ed. 2019).

investment is and the amount of the investment.[42] A project is "discrete" if it is "individual; separate; [or] distinct,"[43] and is "identifiable" if it can be identified.

The faithful application of this narrow authorization is critical to ensuring that ratepayers are protected and that the deviation from traditional ratemaking is limited to the specific circumstances authorized by the statute. As clear as the language in section 62-133.16(c)(1)(a) seems to be, it is worth examining the kinds of costs the statute *does not* authorize to be included in an MYRP.

The requirement that the capital spending projects be "discrete and identifiable" excludes from MYRP eligibility any "program" of spending that does not identify particular new assets that will be placed in service. Put differently, the mere identification of an amount of money and the general purpose for which it will be spent does not satisfy section 62-133.16(c). For example, it clearly would be inappropriate for an MYRP to propose $5 billion in spending for "new generation assets" without specifying what those assets would be and where they would be built.

MYRP rates cannot be increased to reflect mere expenses, such as operation and maintenance, unless those increased expenses are associated with a specific capital investment that went into service that year. That is, MYRP rates cannot include increased

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[42] *See* In re DEC, Docket No. E-7, Sub 1146, at 258 (June 22, 2018). Whether a project is "known and measurable" should be contrasted with the more flexible rule in N.C.G.S. § 62-133.1B, which allows the Commission to authorize water utility rates "based on ***reasonably*** known and measurable capital investments and anticipated reasonable and prudent expenses." (emphasis added). Unlike the statute applicable to water utilities, section 62-133.16 allows MYRP investments that are *actually* known and measurable. *See, e.g.*, Brown v. Brown, 112 N.C. App. 15, 20, 434 S.E.2d 873, 878 (1993) ("It is a tenet of statutory construction that 'a change in phraseology when dealing with a subject raises a presumption of a change in meaning.'" (quoting Latham v. Latham, 178 N.C. 12, 100 S.E. 131 (1919)).

[43] Discrete, *Black's Law Dictionary* (11th ed. 2019).

O&M expenses resulting from existing facilities that are not associated with some new capital project that is placed in service. For example, an MYRP cannot include increased employee salary expenses unless such increases reflect salaries for new personnel employed at a new facility. In short, increases in "traditional" O&M expenses on DEC's existing system may not be authorized through an MYRP.

Furthermore, section 62-133.16(c)(1) does not permit the inclusion in MYRP rates of capital spending *programs* that do not result in new capital *projects* being placed in service, regardless of how instances of such spending may be grouped. Thus, for example, Duke's conventional spending on vegetation management, which has historically been treated as an O&M expense,[44] would not be considered an authorized "capital spending project" because it is ongoing maintenance work that does not result in any project being placed in service.

The fact that DEC has not provided the Commission with a set of discrete and identifiable projects is shown clearly by the fact that DEC's witnesses had difficulty identifying how many projects are included in the proposed MYRP.[45] Rather, DEC provided the Public Staff with a number of projects that overwhelmed Staff's ability to apply the level of scrutiny it normally applies to utility projects, while at the same time providing superficial descriptions of the proposed projects in its testimony to the

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[44] *See, e.g.*, Testimony of Robert Simpson, Docket No. E-7, Sub 1146, Tr. Vol. 16, pp. 102-03 (requesting increase in annual vegetation management expenses including to pay for "distribution line 'hazard tree' cutting"); Order Accepting Stipulation, Deciding Contested Issues, and Requiring Revenue Reduction, Docket No. E-7, Sub 1146, pp. 102-04 (June 22, 2018) (approving increase in vegetation management expense in part to enable hazard tree cutting); Testimony of D. Williamson & T. Williamson, Docket No. E-7, Sub 1214, Tr. Vol. 17, p. 298 (discussing DEC's proposal to increase vegetation management costs based in part on hazard tree cutting expenses);

[45] *E.g.*, Tr. vol. 16, 319-20.

Commission. The Commission cannot rely on stipulations, the *ipse dixit* of witnesses, or the existence of a list of projects to support the conclusion that the proposed projects are in fact discrete and identifiable. Rather, the Commission should look at the testimony and exhibits actually submitted in evidence during the hearing. As explained below, a review of this evidence makes clear that DEC's proposed MYRP projects include a number of "projects" that are not permitted by section 62-133.16(c)(1)(a) because they are not "discrete and identifiable," and in some cases they are not even "capital" spending projects.

First, DEC's Distribution Hazard Tree Removal program is simply a continuation of DEC's historic removal of hazard trees outside of the DEC right-of-way.[46] There are no trees presently marked for removal as part of the program and there is no specific location at which tree removal is expected to be needed.[47] Instead, DEC expects and "intend[s] to find" trees to cut down.[48] The proposed Hazard Tree Removal program is a "spending program" involving "routine identification of trees" that "sets aside an allocation to remove . . . hazard trees."[49]

Vegetation management—including hazard tree removal—is an ongoing process that has historically been treated as an O&M expense.[50] In fact, in its submissions in this

[46] Tr. vol. 8, 116. DEC witness Speros suggested at one point that the costs indicated in the MYRP program are for the acquisition of rights-of-way, Tr. vol. 13, 266-67, but witness Speros also conceded that he would defer to witness Guyton's description of the program, which does not include acquisition of rights of way but rather the cutting of trees outside of DEC's rights of way. Tr. vol. 13, 277-78; *see* Guyton Direct Ex. 6 at 25-27; Tr. vol. 14, 251 ("They're simply removing that hazard tree . . . .").

[47] Tr. vol. 8, 413-15; Tr. vol. 13, 261-62.

[48] Tr. vol. 8, 415.

[49] Tr. vol. 14, 261-62.

[50] *See, e.g.*, *supra* n.44.

case, DEC indicates that some of its MYRP projects will result in O&M savings from decreased vegetation management expenses.[51]

DEC witness Speros contended that DEC's capitalization policy provides for capitalization of some vegetation management expenses,[52] and Public Staff witness Thomas suggested that he believed (subject to check) that capitalization of hazard tree removal expenses is a longstanding policy of DEC.[53] Notably, DEC's capitalization policy is not in evidence; there is no evidence whatsoever regarding what vegetation management expenses qualify for capitalization under the policy; and there is no evidence that the activities within the Hazard Tree Removal program are capitalized under DEC's capitalization policy. Furthermore, the capitalization policy has never been approved by this Commission and DEC's internal capitalization policies are irrelevant to whether this program falls within the scope of "known and measurable" and "discrete and identifiable" *capital* projects authorized as part of an MYRP. Finally, witness Speros contends that "the Company's capitalization policy (which has been developed based on FERC and GAAP guidance), is consistently applied to all vegetation management work."[54] However, witness Speros conceded on cross-examination that vegetation management, including distribution hazard tree removal, has historically been treated as an O&M expense, and that such treatment "sounds appropriate . . . from an accounting perspective."[55]

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[51] Guyton Direct Ex. 8, 21-29. Notably, however, DEC did not calculate the decreased vegetation management expenses, but simply duplicated the savings from avoided outages.
[52] Tr. vol. 12, 567-68.
[53] Tr. vol. 14, 252.
[54] Tr. vol. 12, 567.
[55] Tr. vol. 13, 279.

Notably, witness Speros does not claim that the Company's capitalization policy is *consistent with* FERC and GAAP guidance. In fact, DEC's capitalization policy, to the extent it allows capitalization of tree removal costs other than initial clearing of rights of way, is *contrary to* explicit FERC guidance. FERC has indicated that vegetation management should not be capitalized unless it is the cost of initially clearing a right-of-way during construction; subsequent vegetation management for maintenance and reliability purposes is a maintenance cost that is expensed, not capitalized.[56] As FERC's Division of Audits, Office of Enforcement, has explained in response to a claim that expenses associated with "the removal of danger trees located off existing transmission corridors" should be capitalized:

> Audit staff disagrees with ATSI's interpretation that the expansion of the corridors resulted in a substantial addition to the related transmission lines or system. The purpose of a substantial addition is to make the asset more useful, more efficient, of a greater durability, or of a greater capacity.
>
> Audit staff finds that while the expansion of corridors may improve reliability by decreasing vegetation-caused outages, it does not directly make the transmission assets or system more useful, more efficient, of a greater durability, or of a greater capacity. The Commission's regulations provide for the capitalization of vegetation management costs incurred for the initial clearing of land during construction. Also, the Commission's regulations require vegetation management costs incurred subsequent to the construction phase of a project to be expensed. Vegetation management for plant in service are costs to trim trees, remove trees, prune, and clear brush specifically to ensure the reliability of the transmission system by

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[56] *Compare* 18 C.F.R. Part 101, Account 365, Overhead conductors and devices, Item No. 9 (allowing capitalization for "Tree trimming, initial cost") *with* Account 571, Maintenance of overhead lines (Major only), Item No. 2(k) (identifying "Tree trimming" as a maintenance expense for transmission lines) *and* Account 593, Maintenance of overhead lines (Major only), Item No. 2(k) (identifying "Tree trimming" as a maintenance expense for distribution lines). *See* Exhibit 1, Excerpts from 18 C.F.R. Part 101, attached hereto.

> preventing vegetation-caused failures. Under the Commission's accounting regulations, costs of this nature are recorded as maintenance expense.
>
> * * *
>
> ATSI can recover prudently incurred vegetation management costs properly recorded in Account 571 through its formula rate tariff. However, ATSI's policy of capitalizing vegetation management costs for expanding its existing corridors, removing danger trees in existing corridors, and removing tree limbs around existing poles and lines is not supported by the Commission's accounting regulations. [57]

DEC witness Guyton conceded on cross-examination that the amounts proposed for Hazard Tree Removal are based on an expectation that DEC's historical experience in incurring such expenses will continue. DEC's Hazard Tree Program has been part of its distribution vegetation management work since 2014.[58] The removal of hazard trees from outside of DEC's right of way is a maintenance cost, and does not increase the amount of DEC property that is used and useful in providing service to DEC's customers. In fact, DEC does not claim that anything will be "placed in service" other than "vegetation capital blankets"—i.e., lump sums of money without reference to any specific project. Section 62-133.16(c) refers to *projects* being placed in service, not funds. Upon completion of tree removal work, *nothing* will be placed in service. Like ASTI's rejected capitalization policy, DEC's capitalization policy inappropriately capitalizes maintenance expenses. DEC's attempt to earn a return on its routine O&M expenditures by grouping these expenses together and calling them a "program" should be rejected.

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[57] FERC, Audit of Formula Rates of American Transmission Systems, Inc., Docket No. FA11-8-00, at 16-17 (2013), *available at* https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20130424-3026, attached as Exhibit 2 hereto.

[58] Tr. vol. 8, 19.

Second, DEC's proposed "Hardening & Resilience: Public Interference" program proposes to "target[] . . . outage prone . . . power line sections" and "determin[e] the proper hardening & resiliency solution to reduce the number of outages experienced by customers."[59] As specified in witness Guyton's testimony, the "solution" that will be applied to each power line is unknown; DEC's "design teams will identify the appropriate hardening and resiliency solution"[60] at some later, unspecified time. In other words, DEC has explicitly not identified what it is going to do. DEC is simply requesting the Commission approve a vague, general concept that some lines may be improved, reliability-wise, by applying some unknown method(s). While this could certainly be the case, that does not make the program a "discrete and identifiable" capital spending project. The only evidence in the record is the general idea of what DEC would like to do and the amount of money it would like to spend and earn a return on. Furthermore, as Public Staff witness Thomas pointed out, DEC's submissions indicate that this program will result in O&M savings but DEC does not actually credit any savings to customers, as it must under section 62-133.16(c)(1)(a). This shortcoming is understandable, as it appears quite difficult to quantify the savings expected to result from unknown actions.

Third, DEC's proposed "Infrastructure Integrity" program involves "identification and mitigation of risk factors such as end-of-service equipment, technology obsolescence, and removal of damaged in-service distribution equipment such as capacitors, regulators, reclosers, and other line equipment,"[61] which DEC proposes to perform in conjunction with

[59] Tr. vol. 8, 134.
[60] Guyton Direct Ex. 6 at 15.
[61] Guyton Direct Ex. 6 at 28.

every single other MYRP distribution project it proposes to undertake other than IVVC.[62] In other words, DEC anticipates the need to perform currently unspecified work, as diverse as "[a]sset replacement," "[o]il mitigation," "[g]reenhouse gas mitigation," "[t]echnological obsolescence," "[s]ystem operability to serve dynamic power flows," and "[m]ajor outage root cause studies," but does not currently know what work will need to be done or where.[63] This is not a "discrete and identifiable" investment. DEC requests a staggering $447.4 million for this unspecified purpose, making it one of the largest "programs" proposed for inclusion in the MYRP.

DEC's proposed Cathodic Protection, Targeted Wood Pole Upgrade, and Transmission Hazard Tree Removal[64] programs suffer from similar infirmities. DEC's submissions and testimony do not identify where the work—or even *what* work—involved in any of these projects will take place. For instance, the cathodic protection program will "extend[] the life of the existing transmission towers that deliver electricity from power plants to substations for delivery across the grid" as follows:

> Cathodic Protection improvements install passive protective systems onto structures using highly polarized magnesium anodes that mitigate further corrosion to the structure. Towers that are identified as corroded to the point of impacting structural integrity are addressed through installation of structural braces, or through complete tower replacement when warranted.[65]

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[62] Guyton Direct Ex. 5A at 1-6.

[63] Guyton Direct Ex. 6 at 28.

[64] Of course, the Transmission Hazard Tree Removal program suffers from the same infirmity as its distribution counterpart: It is an improper attempt to capitalize maintenance costs that are required to be expensed, not capitalized, under FERC accounting guidance. *See supra* notes 56-57 and accompanying text.

[65] Maley Direct Ex. 4 at 9.

That is, once DEC (in the future) identifies where and when cathodic protection is needed—and what kind—it proposes to undertake whatever that work may be. This concept appears to be prudent in general, but it is not "discrete and identifiable"; it is purposefully continuous and unidentified. Similarly, the Transmission Hazard Tree Removal Program reflects ongoing work that DEC plans to undertake once it has "optimized" the work that needs to be done based on "intelligence obtained through remote sensing, inspections, and field assessments."[66] Likewise, the Targeted Wood Pole Upgrades proposed by DEC do not specify where DEC plans to replace wood poles, and from the provision of the exact same amount of money for each month of the MYRP, it is clear that DEC merely anticipates that some wood pole replacement work will be done and has not identified where or when such work will be completed.[67]

Together, the six programs above include proposed spending more than $700 million over the course of the MYRP, with DEC's exhibits and testimony providing no information regarding what, precisely, a single dollar of that money will be spent on. More concretely, these programs involve work that DEC admits it has not, will not and—critically—*cannot* identify until some later date. These spending programs do not represent "discrete and identifiable" projects. On the contrary, they appear to be nothing more than buckets of money that DEC intends to employ if and when DEC identifies that the relevant kinds of work need to be done.

These kinds of spending programs are not what the General Assembly intended when it permitted the inclusion of "known and measurable" and "discrete and identifiable"

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[66] Maley Direct Ex. 4 at 19.
[67] Maley Direct Ex. 2 at 6-7.

projects in the MYRP. The purpose of the MYRP is not to increase rates to cover ongoing O&M expenses (such as vegetation management) that should already be included in test-year expenses in the base rate case. The purpose of submitting information regarding proposed MYRP projects to the Commission is to allow the Commission to determine, before money is spent and DEC begins collecting a return through rates, whether such spending will be reasonable and prudent. By definition, the Commission cannot make such a determination if DEC has not determined what the work will be.

Accordingly, if the Commission approves an MYRP, the costs associated with the programs identified above be must be excluded from the determination of rates under the MYRP as exceeding the authority granted by statute.

III. DEC'S MYRP SUBMISSION DOES NOT COMPLY WITH RULE R1-17B(D)(2)(K) AND ANY PROJECT WITH EXPECTED O&M SAVINGS UNACCOMPANIED BY EVIDENCE OF THE AMOUNT OF SUCH SAVINGS MUST BE DISALLOWED.

Section 62-133.16(c)(1)(a) specifies that the rates applicable under any approved MYRP must be "net of operating benefits." Reflecting this requirement, Rule R1-17B(d)(2)(k) requires proposed MYRP submitted to include "[p]rojected operating benefits" associated with each proposed MYRP project. DEC's submissions and testimony indicate an expectation that many of the proposed MYRP projects will result in operating benefits, including reductions in operating expenses, which Rule R1-17B(d)(2)(k) required DEC to identify and section 62-133.16(c)(1)(a) requires be netted out of DEC's MYRP revenues to the benefit of ratepayers. However, despite acknowledging that many projects would result in decreased operating expenses, DEC failed to estimate the expected O&M savings for many of the proposed MYRP programs.

These programs should be excluded from any approved MYRP for failing to comply with Rule R1-17B(d)(2)(k).

DEC predicts it will decrease or avoid O&M costs through the following proposed MYRP programs:

- Distribution Hardening & Resiliency: Laterals[68];
- Distribution Hardening & Resiliency: Public Interference[69];
- Distribution Hardening & Resiliency: Storm[70];
- Long Duration Interruption[71];
- Targeted Undergrounding[72];
- Towers, Shelters & Power Supplies[73];
- Transmission Line H&R[74];
- Transmission Substation H&R[75];
- Transmission Vegetation Management[76];
- Transmission – Breaker Upgrades[77];
- Transformer Upgrades[78];

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[68] Guyton Direct Ex. 6 at 14.
[69] Guyton Direct Ex. 6 at 17.
[70] Guyton Direct Ex. 6 at 20, Tr. vol. 8, 123, 134.
[71] Guyton Direct Ex. 6 at 35, 37; Tr. vol. 8, 134-35.
[72] Guyton Direct Ex. 6 at 45; Tr. vol. 8, 135.
[73] Guyton Direct Ex. 7 at 10.
[74] Maley Direct Ex. 4 at 12.
[75] Maley Direct Ex. 4 at 17.
[76] Maley Direct Ex. 4 at 21; Tr. vol. 8, 289.
[77] Maley Direct Ex. 4 at 23-25.
[78] Maley Direct Ex. 4 at 27-29; Tr. vol. 8, 287.

- Transmission – H&R: Transformers[79]; and
- Transmission Capacity & Customer Planning.[80]

The primary operational benefit of each of these programs is the reduction in costs associated with outages.[81] In addition to these programs for which DEC specifically acknowledges savings from avoided outages, DEC identifies a number of programs that are intended, in whole or in part, to prevent or reduce the number or severity of outages:

- Distribution Hazard Tree Removal[82];
- Distribution Infrastructure Integrity[83];
- Capacity[84];
- Distribution Automation[85];
- Energy Storage[86];
- Self-Optimizing Grid[87];
- ADMS[88]; and
- Transmission: System Intelligence.[89]

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[79] Maley Direct Ex. 4 at 30.
[80] Maley Direct 40; Maley Direct Ex. 4 at 32.
[81] *See* Guyton Direct Ex. 6 at 14, 17, 20, 37, 45; Guyton Direct Ex. 7 at 10; Maley Direct Ex. 4 at 12, 17, 21, 25, 27, 30; Tr. vol. 8, 138.
[82] Guyton Direct Ex. 6 at 25, 27; Tr. vol. 8, 135.
[83] Guyton Direct Ex. 6 at 28, 30; Tr. vol. 8, 135-36.
[84] Guyton Direct Ex. 6 at 6.
[85] Guyton Direct Ex. 6 at 7; Tr. vol. 8, 116.
[86] Guyton Direct Ex. 6 at 22.
[87] Guyton Direct Ex. 6 at 38; Tr. vol. 8, 135.
[88] Guyton Direct Ex. 7 at 6; Tr. vol. 8, 147.
[89] Maley Direct Ex. 4 at 5-7.

Despite DEC's repeated acknowledgments that avoiding or reducing the severity of outages results in O&M savings, DEC's submissions do not identify any credit for O&M savings for Distribution Automation, ADMS, Capacity Upgrade projects, Distribution Hazard Tree Removal, Breaker Upgrades, Capacity & Customer Planning, Transmission Substation H&R, Transmission System Intelligence, Transmission Line H&R, Transmission Transformers, or Transmission Vegetation Management.[90] Importantly, DEC's submissions do not show that there would be no net operating benefits from these programs. Rather, they show that DEC *did not calculate the O&M savings* and *did not identify the net operating benefits*.

Furthermore, Public Staff witness Thomas points out that DEC failed to calculate the O&M savings from certain generation projects.[91]

Because DEC acknowledges there will be O&M savings but has not identified the expected O&M savings from these projects, there is no evidentiary basis to establish the rates authorized by section 62-133.16 for an MYRP including these projects. Accounting for such savings is, on its face, a critical and necessary component of the MYRP authorization.

Accordingly, these projects cannot be included in any MYRP approved by the Commission, and CUCA requests that the costs associated with the programs identified above be excluded from the determination of rates under any approved MYRP.

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[90] Guyton Direct Ex. 8, at 1-4, 11-15; Taylor Direct Ex. 1, at 1-5, 14-15.
[91] Tr. vol. 14, 191-92.

IV. DEC'S PROPOSED MYRP DOES NOT MINIMIZE INTERCLASS SUBSIDIES TO THE MAXIMUM EXTENT PRACTICABLE.

Under section 62-133.16(b),

> the Commission is authorized to approve performance-based regulation . . . so long as . . . interclass subsidization of ratepayers is minimized to the greatest extent practicable by the conclusion of the MYRP period.[92]

Thus, subsection (b) places a substantive limit on the authority of the Commission to approve a request for performance-based regulation: In order to approve any PBR application, the Commission must first conclude that interclass subsidization is minimized "to the greatest extent practicably by the conclusion of the MYRP period."[93]

In the DEP Order, the Commission concluded that that DEP's proposed PBR should be authorized because

> DEP's approach of gradually reducing the subsidies between classes by utilizing a variance reduction of 10% is reasonable and that the 10% variance reduction approach moves towards eventual rate parity/minimization of interclass subsidization while, at the same time, balancing the other requirements of the PBR Statute including that no class of customer is unreasonably harmed or faces a sudden and substantial increase in rates resulting in rate shock. . . . Thus, balancing its obligations under the PBR Statute to ensure allocation of revenue requirement based on cost causation, minimization of interclass subsidization, equitable treatment of customer classes, and avoidance of unreasonable prejudice and rate shock, the Commission concludes that DEP's PBR Application as amended by the stipulations and the various provisions of this Order, is in alignment with cost causation or reasonably headed that way, avoids unreasonable harm to any class of customers, and does not unreasonably prejudice an class of customers or otherwise result in rate shock.[94]

In essence, the Commission determined that the mandatory requirement of subsection 62-133.16(b) could be satisfied by balancing that requirement with the

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[92] N.C.G.S. § 62-133.16(b).
[93] *Id.*
[94] DEP Order, at 236.

considerations listed in subsection 62-133.16(d). Notably, however, the items listed in subsection (d) are not criteria that the Commission is required to find before it can approve a PBR application. Instead, they are merely factors that the Commission must *consider*.

The term "practicable" means that something is "capable of being accomplished" or "feasible in a particular situation."[95] By requiring a proposed PBR application to minimize interclass subsidies to the "greatest extent practicable by the conclusion of the MYRP period," the General Assembly did not intend for the Commission to simply check a box that the proposed PBR "moves toward" rate parity. Rather, the section requires that the rates approved actually will achieve the greatest reduction in interclass subsidies that can be achieved in light of other limitations.

Here, DEC has proposed a 10% reduction in subsidies because, when it examined the effect of a 25% reduction in subsides, it determined there would be an inappropriately large rate increase for the lighting class.[96] However, as CUCA witness Pollock points out, DEC's proposed treatment of interclass subsidies does not appear to be consistent with the requirement in N.C.G.S. 62-133.16(b) to allocate costs among customer classes according to cost-causation.[97]

There is nothing in Chapter 62 of the North Carolina General Statutes or in the decisions of this Commission that required DEC to reduce interclass subsidies by some uniform percentage for each class. For instance, DEC has provided no evidence what effect on each class it would have to reduce the subsidy to the Lighting Class by only 10%, while reducing by a greater amount (or eliminating entirely) the subsidies among other classes.

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[95] Practicable, *Black's Law Dictionary* (11th ed. 2019).
[96] Tr. vol. 10, 5.
[97] Tr. vol. 15, 445-47.

The conclusion that a 10% reduction is all that is practicable because a single customer class would perceive a rate increase to be shocking is nonsensical. Interclass subsidies should be reduced to the greatest extent practicable on a class-by-class basis, eliminating them where possible and reducing them by some smaller amount where elimination is not possible. DEC's proposal does not even consider this option.

As a result, the evidence before the Commission does not show that greater reductions in interclass subsidies are impracticable. At best, DEC makes the case that one class could be negatively impacted by further decreasing its subsidies. That is not sufficient evidence to conclude that the proposed PBR reduces interclass subsidies "to the greatest extent practicable," as required by subsection 62-133.16(c). Accordingly, the Commission lacks a sufficient basis for approving DEC's PBR. The Commission should either require DEC to submit a proposal to further reduce interclass subsidies or the PBR application should be rejected.

V. DEC HAS NOT SHOWN THAT ITS GIP SPENDING ON SOG WAS REASONABLE AND PRUDENT.

In its previous rate case, where DEC sought approval for various Grid Improvement Plan ("GIP") projects, this Commission allowed DEC to defer certain GIP costs but noted that its decision

> allows DEC to treat costs incurred in pursuing the settled GIP programs as regulatory assets pending a prudence and reasonableness determination in a later rate case. DEC remains fully at risk for the reasonableness and prudence determination of its GIP costs and for its ultimate recovery from customers, as would be the case if DEC simply undertook these programs without a deferral and then sought recovery of the costs in a rate case.[98]

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[98] Order Accepting Stipulations, Granting Partial Rate Increase, and Requiring Customer Notice, Docket No. E-7, Sub 1214, at 141 (Mar. 31, 2021) (hereinafter, "DEC GIP Order").

DEC's witness Oliver presented Self-Optimizing Grid ("SOG") as a "'no regrets' investment that provides significant value for customers in multiple ways" and indicated that deferral accounting would enable DEC "to bring the benefits to customers sooner."[99] The Commission's decision in that case noted the concern of CUCA witness O'Donnell that DEC's recovery for GIP projects should be made contingent on DEC's achievement of the reliability improvements expected by DEC, but ultimately gave

> weight to the fact that . . . Duke and the Public Staff will jointly develop metrics to monitor the implementation and measure the effectiveness of the programs. Further, DEC agreed to report such metrics, including cost-effectiveness, for each of the agreed programs on a regular basis beginning with expenditures made during the last six months of 2020. . . . The Company has committed to report to the Commission on the effectiveness and cost-effectiveness of the programs. The Commission will hold the Company to this commitment, and the Commission anticipates that these data will be taken into consideration by the Commission in the cost recovery proceedings.[100]

It must be noted that the Commission's decision to allow deferral accounting for GIP projects was controversial, including because it was issued over the dissent of two Commissioners who questioned how a future Commission—this Commission—would address DEC's achievement, or failure to achieve, expected reliability benefits.[101] The results presented by DEC bear out the concerns raised by CUCA witness O'Donnell and the dissenting Commissioners.

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[99] DEC GIP Order at 126, 132.

[100] *Id.* at 140.

[101] DEC GIP Order, Comm'r Brown-Bland, dissenting, at 1-4; *id.*, Comm'r Clodfelter, dissenting in part, at 8-9 ("The better course would be to evaluate actual GIP expenditures made by the Company and actual results achieved for customers in the context of all other issues and decisions that culminate in the setting of just and reasonable rates in a future general rate case.").

DEC spent approximately $376 million on SOG from 2020 through the end of 2022.[102] In its biannual report, DEC claims that without SOG, DEC's SAIDI metric would have been 189 in 2022.[103] However, DEC's actual reported SAIDI for 2022 was only slightly lower at 185.[104] In other words, the $376 million investment by DEC resulted in a SAIDI decrease of 4 minutes of outage time per customer, or 2.1%, as customers actually experienced worsening outage time. While it is certainly the case that reliability improvements were not the only benefit of SOG espoused by DEC in the last rate case, reliability benefits were the overwhelming majority of the benefits expected from the program.[105]

Self-Optimizing Grid appears to be delivering some benefit, but it is not delivering the benefit DEC claimed when it sought deferral accounting. Since approximately 44% of DEC's outages are caused by vegetation,[106] the evidence does not support a conclusion that DEC has prudently allocated its resources to provide, in a cost-effective manner, the customer reliability benefits that were asserted as a basis for the Commission's prior order. Furthermore, since DEC's actual reported SAIDI performance has continued to worsen since 2022,[107] the purported reliability benefits of pursuing SOG at the cost of $376 million

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[102] Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's December 2022 NC GIP Biannual Report Executive Summary Docket Nos. E-7, Sub 1214B and E-2, Sub 1219B, at 11 (Mar. 1, 2023) (hereinafter, "GIP Biannual Report 2022").

[103] GIP Biannual Report 2022 at 10. Notably, the with-SOG SAIDI reported in the Biannual Report is 181.7, but that does not match what DEC reports was actually achieved in 2022. *See infra* n.104. That is, the Biannual Report appears to take credit for savings that did not occur.

[104] Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's Quarterly Service Reliability Report (Fourth Quarter 2022), Docket No. E-100, Sub 138A (Jan. 31, 2023).

[105] Oliver Ex. 7 at 185, Docket No. E-7, Sub 1214.

[106] Tr. vol. 15, 123.

[107] Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's Quarterly Service Reliability Report (Second Quarter 2023) Docket No. E-100, Sub 138A; *see* Tr. vol. 8, 103.

appear to be academic rather than actual. While DEC suggests that things would have been *even worse* without SOG, there is no evidence of that, since DEC could have (prudently) spent the money on something else, as shown by the fact that SAIDI has worsened despite the implementation of SOG.

DEC has failed to carry its burden of demonstrating promised improvements in reliability, and the marginal reliability benefit it has achieved by spending nearly $400 million over the course of two years does not support a finding of prudence. For instance, DEC's proposed Reliability PIM values a 20-point increase in SAIDI at $1.5 million,[108] suggesting—based on DEC's own proposed metrics—that DEC spent some $400 million for a 4-point SAIDI improvement with a monetary equivalence of $300,000. From any angle, spending hundreds of times as much on SOG to improve SAIDI by 4 points—while SAIDI actually got *worse* in real terms—cannot be considered prudent given that purported reliability improvements were the basis for the Commission's approval of the expenditure.

Accordingly, CUCA respectfully requests the Commission disallow the recovery of DEC's SOG spending because DEC has failed to satisfy its burden to show that such spending was prudent and reasonable.

VI. ASPECTS OF DUKE'S PROPOSED INDUSTRIAL RATE DESIGN CHANGES SHOULD BE REVISED.

CUCA witness Pollock identified several issues with DEC's proposed rates that are especially impactful for DEC's industrial customers.

[108] Agreement and Stipulation of Settlement on Performance Incentive Mechanisms, Tracking Metrics and Decoupling Mechanism, Docket No. E-7, Sub 1276 (Aug. 22, 2023).

A. DEC's proposed time-of-use periods should be longer.

DEC proposes new time-of-use ("TOU") periods based as applied in its previously approved Critical Peak Pricing rates, establishing summer (May to September) peak hours from 6 p.m. to 9 p.m. and summer discount hours from 1 a.m. to 6 a.m.; and non-summer peak hours from 6 a.m. to 9 p.m., with winter discount hours from 1 a.m. to 3 a.m. and 11 a.m. to 4 p.m.[109]

However, as CUCA witness Pollock notes, the proposed TOU schedule—which was developed for a narrow class of rates, but which DEC now seeks to extend more generally—provides for exceedingly short discount windows that fail to give manufacturers the incentive shift use from high-demand to low-demand time periods.[110] In addition, the periods proposed by DEC do not seem to align well with the peak cost hours identified by DEC's cost-duration model.[111] To correct this issue, witness Pollock suggests increasing the duration of the discount and peak periods to eight hours in length so that they can be matched to manufacturing work shifts.[112]

CUCA supports the suggested modifications to the TOU schedule to better align TOU rates with the needs, usage patterns, and incentives of manufacturers.

B. DEC's HP tariff should not include a 20% incentive margin increase.

Witness Pollock criticizes DEC's proposal to increase the Incentive Margin for the HP tariff from $5 to $6 per MWh.[113] As witness Pollock notes, while the Incentive Margin

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[109] Tr. vol. 10, 90; Byrd Direct. Ex. 1.
[110] Tr. vol. 15, 454.
[111] Tr. vol. 15, 452.
[112] Tr. vol. 15, 454-55.
[113] Tr. vol. 15, 455.

appears to have been designed to compensate DEC for the risk that hourly prices (set a day ahead) will differ from DEC's marginal costs, there is no evidence that DEC's risk in this regard has changed in any meaningful way to support the proposed 20% increase.[114]

On rebuttal, DEC witnesses Beveridge and Byrd contend that the Incentive Margin is also intended to recoup fixed transmission and distribution costs, and suggest that the 20% increase in the Incentive Margin is justified by DEC's attempt to align the charge with DEP's analogous Variable Adder charge.[115] However, witness Beveridge confirmed on cross-examination that DEC's Incentive Margin charge has no supporting cost analysis, and that there is no basis for increasing charges based merely on the passage of time.[116]

As witness Pollock points out and the DEC witnesses do not dispute, DEC has provided no evidence of any cost-based reason for the proposed increase in the Incentive Margin. The passage of time and the desire to make a DEC charge more like an analogous DEP charge are not relevant concerns for setting a DEC rate. Accordingly, CUCA respectfully requests the Commission deny DEC's request to increase the HP tariff Incentive Margin.

C. There should not be a mandatory CBL reset for customers on the HP tariff.

DEC proposes to recalculate the customer base load ("CBL")—which defines a level above which customers are charged hourly marginal energy prices—for customers on the HP tariff every four years.[117] However, as CUCA witness Pollock points out,

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[114] Tr. vol. 15, 455.
[115] Tr. vol. 10, 207-08, 282-83.
[116] Tr. vol. 10, 280, 283-84.
[117] Tr. vol. 10, 104.

requiring a mandatory reset of the CBL every four years as proposed by DEC will remove the incentive provided by hourly marginal pricing during grid constrained periods from customers that could be responsive to price signals.[118] On rebuttal, DEC witnesses Beveridge and Byrd contend that DEC's proposed Load Response Adjustment provision addresses this concern, in part.[119]

CUCA supports witness Pollock's position and respectfully requests the Commission deny DEC's proposal to require a mandatory reset of HP tariff customers' CBL every four years.

D. The CAP program should be paid for by residential customers only.

Witness Pollock correctly notes that the Customer Assistance Program ("CAP"), if paid for by ratepayers outside of the Residential Class, will inappropriately increase interclass subsidies.[120] Notably, there appears to be no statutory authority in Chapter 62 of the North Carolina General Statutes that would authorize the Commission to approve such a scheme. Witness Pollock points out that the proposal would require classes of ratepayers that are ineligible for CAP assistance to provide approximately 50% of the program's funding.[121] In order to achieve consistency with the requirement to minimize interclass subsidies to the "greatest extent practicable," the Commission should revise the program so that all of its funding is derived from the Residential class.

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[118] Tr. vol. 15, 456-57.
[119] Tr. vol. 10, 209-210.
[120] Tr. vol. 15, 458.
[121] Tr. vol. 15, 457.

VII. THE PROPOSED RELIABILITY PIM DOES NOT PROVIDE ADEQUATE INCENTIVE FOR DEC TO IMPROVE ITS SERVICE RELIABILITY.

The proposed Reliability PIM set forth in the PIMs Settlement[122] among DEC, the Public Staff, and CIGFUR III, would penalize DEC if it fails to meet certain reliability thresholds during the MYRP period.[123] The stipulating parties agreed on the following table of thresholds and applicable penalties:

	RY1 (2024 data)	RY2 (2025 data)	RY3 (2026 data)
SAIDI 5-year historic average (2018-2022) adjusted for expected SOG improvements *No penalty for SAIDI below Tier 1 threshold*	**177**	**174**	**172**
SAIDI threshold for Tier 1 penalty *Financial penalty if SAIDI above threshold value*	**197** *$1.5 million*	**194** *$4 million*	**192** *$6 million*
SAIDI threshold for Tier 2 penalty *Financial penalty if SAIDI above threshold value*	**217** *$3 million*	**214** *$7 million*	**212** *$9 million*
SAIDI threshold for Tier 3 penalty *Financial penalty if SAIDI above threshold value*	**237** *$9 million*	**234** *$13 million*	**232** *$15 million*

The proposed PIM is flawed both in substance and structure, and fails to truly incent DEC to achieve the reliability improvements it purports the MYRP projects should enable.

Substantively, the SAIDI thresholds before penalties are imposed are far too high. In its previous rate case, DEC promised that its GIP investments would improve grid reliability and DEC claims in this case that the further investments it plans to make under

[122] Agreement and Stipulation of Settlement on Performance Incentive Mechanisms, Tracking Metrics and Decoupling Mechanism, Docket No. E-7, Sub 1276 (Aug. 22, 2023).
[123] *See id.* 4.

the MYRP will also improve reliability. However, in its most recent quarterly reliability compliance filing, DEC reported that its SAIDI metric for the 12-month period ending June 30, 2023, was 199.[124] DEC will be able to avoid a penalty entirely by achieving a marginal improvement in SAIDI.

The penalty thresholds should be more stringent than proposed in the PIMs Settlement. In its last rate case, DEC forecast that it could reduce SAIDI to between 157 and 193 by 2019 from the 214 achieved in 2018.[125] In other words, DEC had high confidence that it could reduce SAIDI by 21 to 57 points in a single year. DEC actually achieved a SAIDI of: 175 for 2019,[126] at the midpoint of the projected range; 175 in 2020[127]; 154 in 2021[128]; 185 in 2022[129]; and 199 for the most recently reported 12-month period.[130] In this proceeding, DEC witness Guyton indicated that its GIP investments have "contributed to the improving trends" in SAIDI and SAIFI.[131] However, witness Guyton's testimony, filed January 19, 2023, relied on a trendline omitting DEC's worsening reliability performance in 2022, which DEC filed docket E-100, Sub 138A only 12 days later.

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[124] Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's Quarterly Service Reliability Report (Second Quarter 2023) Docket No. E-100, Sub 138A; *see* Tr. vol. 8, 103.

[125] Tr. vol. 11, 604-05, Docket No. E-7, Sub 1214 (Oct. 23, 2019) (testimony of Jay W. Oliver).

[126] Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's Quarterly Service Reliability Report (Fourth Quarter 2019), Docket No. E-100, Sub 138A (Jan. 29, 2020).

[127] Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's Quarterly Service Reliability Report (Fourth Quarter 2020), Docket No. E-100, Sub 138A (Jan. 29, 2021).

[128] Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's Quarterly Service Reliability Report (Fourth Quarter 2021), Docket No. E-100, Sub 138A (Jan. 28, 2022).

[129] Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's Quarterly Service Reliability Report (Fourth Quarter 2022), Docket No. E-100, Sub 138A (Jan. 31, 2023).

[130] *See supra* n.124.

[131] Tr. vol. 8, 114-16.

DEC has proposed MYRP projects on the basis that ratepayers will see reliability improvements, highlighting reliability as the first and primary benefit of many of the MYRP projects.[132] If these purported benefits do not materialize as actual and substantial reliability improvements, DEC should be penalized. Accepting the proposed threshold of 197 will allow DEC to avoid a penalty by simply maintaining reliability near its current levels, which is not commensurate with DEC has told the Commission its MYRP projects are supposed to achieve. Accordingly, the penalty threshold should be set significantly lower than 197. For all of the money DEC proposes to spend with the goal of improving reliability, it would not be unreasonable for the Commission to expect DEC to lower SAIDI to at least the 175 achieved in 2019 and 2020, and to penalize DEC if it fails to do so.

Second, the penalty structure does not provide the right incentives for DEC to focus on reliability. The proposed penalties are tiered, meaning that there is no incentive for DEC to improve reliability once SAIDI has reached a particular range. For instance, if DEC fails to achieve the 197 threshold, it has no incentive not to allow SAIDI to further slip to, say, 215, even though that would mean significantly worse performance.

To fix this issue, the penalty imposed on DEC should be a continuous or "sliding" penalty, so that each single digit increase in SAIDI will result in a higher penalty, and each improvement in SAIDI will result in a lower penalty. For instance, the Commission could impose a penalty of $200,000 for each point increase in SAIDI above 175 in Rate Year 1; $300,000 for each point above 173 in Rate Year 2; and $400,000 for each point above 170 in Rate Year 3, capped only by the maximum 1% of DEC's revenue requirement for

[132] Tr. vol. 8, 106, 132-39.

penalties under section 62-133.16(c)(4). The following table illustrates what these penalties would be for certain achieved levels of SAIDI:

	Penalty		
SAIDI	**Rate Year 1**	**Rate Year 2**	**Rate Year 3**
175	0	$600,000	$2 million
185	$2 million	$3.6 million	$6 million
195	$4 million	$6.6 million	$10 million
205	$6 million	$9.6 million	$14 million
215	$8 million	$12.6 million	$18 million
225	$10 million	$15.6 million	$22 million
235	$12 million	$18.6 million	$26 million
Above 235	$200,000 per point	$300,000 per point	$400,000 per point

This structure would appropriately incent DEC to achieve and maintain SAIDI at or below 175, to show at least some marginal improvement over the course of the MYRP, and to increase penalties year-over-year for failure to achieve such improvement.[133]

CUCA respectfully requests that, if PBR is approved, the Reliability PIM be established as proposed herein.

CONCLUSION

In sum, CUCA respectfully requests that the Commission:

(1) Authorize a return on equity of less than 9.8%;

(2) Reject DEC's proposed MYRP, including because it fails to satisfy the requirement that interclass subsidies be minimized to the greatest extent practicable; or, in the alternative,

[133] For comparison, DEP's worst reported SAIDI since 2019 was 149, achieved in 2019. *See supra* n.126.

(3) Exclude from the MYRP any and all projects that DEC has failed to show are "discrete and identifiable" capital spending projects, including "Distribution Hazard Tree Removal," "Hardening & Resilience: Public Interference," "Infrastructure Integrity," "Cathodic Protection," "Targeted Wood Pole Upgrade," and "Transmission Hazard Tree Removal";

(4) Exclude from the MYRP any and all projects for which DEC has not provided a calculation of net operations benefits, including but not limited to Distribution Automation, ADMS, Capacity Upgrade projects, Distribution Hazard Tree Removal, Breaker Upgrades, Capacity & Customer Planning, Transmission Substation H&R, Transmission System Intelligence, Transmission Line H&R, Transmission Transformers, or Transmission Vegetation Management;

(5) Require DEC to submit alternative rates further minimizing interclass subsidies by allowing the amount of subsidy reduction to vary by class;

(6) Exclude the costs of DEC's Self-Optimizing Grid deferred spending from authorized rates;

(7) Refine the rates proposed by DEC as set forth herein, including by:

(a) Extending time-of-use peak periods to eight hours;

(b) Rejecting DEC's unfounded proposal to increase its Incentive Margin under Schedule HP by 20%;

(c) Eliminating DEC's proposed mandatory CBL reset; and

(d) Confining contribution to the Customer Assistance Program to the Residential Customer class; and

(8) Granting such other relief as necessary to ensure just and reasonable rates.

Respectfully submitted, this 11th day of October, 2023.

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Counsel for CUCA

Certificate of Service

I hereby certify that a copy of the foregoing CUCA'S POST-HEARING BRIEF has been served this day upon all parties of record in this proceeding, or their legal counsel, by electronic mail.

This the 11th day of October, 2023.

BROOKS, PIERCE, MCLENDON,
HUMPHREY & LEONARD, LLP

Matthew B. Tynan

EXHIBIT 1

CROSS REFERENCES: For application of uniform system of accounts to Class C and D public utilities and licensees, see part 104 of this chapter. For statements and reports, see part 141 of this chapter.

Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provisions of the Federal Power Act

Definitions

When used in this system of accounts:

1. *Accounts* means the accounts prescribed in this system of accounts.

2. *Actually issued*, as applied to securities issued or assumed by the utility, means those which have been sold to bona fide purchasers for a valuable consideration, those issued as dividends on stock, and those which have been issued in accordance with contractual requirements direct to trustees of sinking funds.

3. *Actually outstanding*, as applied to securities issued or assumed by the utility, means those which have been actually issued and are neither retired nor held by or for the utility; provided, however, that securities held by trustees shall be considered as actually outstanding.

4. *Amortization* means the gradual extinguishment of an amount in an account by distributing such amount over a fixed period, over the life of the asset or liability to which it applies, or over the period during which it is anticipated the benefit will be realized.

5. A. *Associated (affiliated) companies* means companies or persons that directly, or indirectly through one or more intermediaries, control, or are controlled by, or are under common control with, the accounting company.

B. *Control* (including the terms *controlling*, *controlled by*, and *under common control with*) means the possession, directly or indirectly, of the power to direct or cause the direction of the management and policies of a company, whether such power is exercised through one or more intermediary companies, or alone, or in conjunction with, or pursuant to an agreement, and whether such power is established through a majority or minority ownership or voting of securities, common directors, officers, or stockholders, voting trusts, holding trusts, associated companies, contract or any other direct or indirect means.

6. *Book cost* means the amount at which property is recorded in these accounts without deduction of related provisions for accrued depreciation, amortization, or for other purposes.

7. *Commission*, means the Federal Energy Regulatory Commission.

8. *Continuing Plant Inventory Record* means company plant records for retirement units and mass property that provide, as either a single record, or in separate records readily obtainable by references made in a single record, the following information:

A. For each retirement unit:

(1) The name or description of the unit, or both;

(2) The location of the unit;

(3) The date the unit was placed in service;

(4) The cost of the unit as set forth in Plant Instructions 2 and 3 of this part; and

(5) The plant control account to which the cost of the unit is charged; and

B. For each category of mass property:

(1) A general description of the property and quantity;

(2) The quantity placed in service by vintage year;

(3) The average cost as set forth in Plant Instructions 2 and 3 of this part; and

(4) The plant control account to which the costs are charged.

9. *Cost* means the amount of money actually paid for property or services. When the consideration given is other than cash in a purchase and sale transaction, as distinguished from a transaction involving the issuance of common stock in a merger or a pooling of interest, the value of such consideration shall be determined on a cash basis.

10. *Cost of removal* means the cost of demolishing, dismantling, tearing down or otherwise removing electric plant, including the cost of transportation and handling incidental thereto. It does not include the cost of removal

that the related balance would be necessary to be retained to offset future group item tax deficiencies.

283 Accumulated deferred income taxes—Other.

A. This account shall include all credit tax deferrals resulting from the adoption of the principles of comprehensive interperiod income tax allocation described in General Instruction 18 of this system of accounts other than those deferrals which are includible in Accounts 281, Accumulated Deferred Income Taxes—Accelerated Amortization Property and 282, Accumulated Deferred Income Taxes—Other Property.

B. This account shall be credited and accounts 410.1 Provision for Deferred Income Taxes, Utility Operating Income, or 410.2, Provision for Deferred Income Taxes, Other Income and Deductions, as appropriate, shall be debited with tax effects related to items described in paragraph A above where taxable income is lower than pretax accounting income due to differences between the periods in which revenue and expense transactions affect taxable income and the periods in which they enter into the determination of pretax accounting income.

C. This account shall be debited and accounts 411.1, Provision for Deferred Income Taxes—Credit, Utility Operating Income or 411.2, Provision for Deferred Income Taxes—Credit, Other Income and Deductions, as appropriate, shall be credited with tax effects related to items described in paragraph A above where taxable income is higher than pretax accounting income due to differences between the periods in which revenue and expense transactions affect taxable income and the periods in which they enter into the determination of pretax accounting income.

D. Records with respect to entries to this account, as described above, and the account balance, shall be so maintained as to show the factors of calculation with respect to each annual amount of the item or class of items.

E. The utility is restricted in its use of this account to the purposes set forth above. It shall not transfer the balance in the account or any portion thereof to retained earnings or to any other account or make any use thereof except as provided in the text of this account, without prior approval of the Commission. Upon the disposition by sale, exchange, transfer, abandonment or premature retirement of items on which there is a related balance herein, this account shall be charged with an amount equal to the related income tax effect, if any, arising from such disposition and account 411.1, Provision For Deferred Income Taxes—Credit, Utility Operating Income, or 411.2, Provision For Deferred Income Taxes—Credit, Other Income and Deductions, as appropriate, shall be credited. When the remaining balance, after consideration of any related tax expenses, is less than $25,000, this account shall be charged and account 411.1 or 411.2, as appropriate, credited with such balance. If after consideration of any related income tax expense, there is a remaining amount of $25,000 or more, the Commission shall authorize or direct how such amount shall be accounted for at the time approval for the disposition of accounting is granted.

When plant is disposed of by transfer to a wholly owned subsidiary, the related balance in this account shall also be transferred. When the disposition relates to retirement of an item or items under a group method of depreciation where there is no tax effect in the year of retirement, no entries are required in this account if it can be determined that the related balance would be necessary to be retained to offset future group item tax deficiencies.

Electric Plant Chart of Accounts

1. INTANGIBLE PLANT

301 Organization.
302 Franchises and consents.
303 Miscellaneous intangible plant.

2. PRODUCTION PLANT

A. STEAM PRODUCTION

310 Land and land rights.
311 Structures and improvements.
312 Boiler plant equipment.
313 Engines and engine-driven generators.
314 Turbogenerator units.
315 Accessory electric equipment.
316 Miscellaneous power plant equipment
317 Asset retirement costs for steam production plant.

B. NUCLEAR PRODUCTION

320 Land and land rights (Major only).
321 Structures and improvements (Major only).
322 Reactor plant equipment (Major only).
323 Turbogenerator units (Major only).
324 Accessory electric equipment (Major only).
325 Miscellaneous power plant equipment (Major only).
326 Asset retirement costs for nuclear production plant (Major only).

C. HYDRAULIC PRODUCTION

330 Land and land rights.
331 Structures and improvements.
332 Reservoirs, dams, and waterways.
333 Water wheels, turbines and generators.
334 Accessory electric equipment.
335 Miscellaneous power plant equipment.
336 Roads, railroads and bridges.
337 Asset retirement costs for hydraulic production plant.

D. OTHER PRODUCTION

340 Land and land rights.
341 Structures and improvements.
342 Fuel holders, producers, and accessories.
343 Prime movers.
344 Generators.
345 Accessory electric equipment.
346 Miscellaneous power plant equipment.
347 Asset retirement costs for other production plant.
348 Energy Storage Equipment—Production

3. TRANSMISSION PLANT

350 Land and land rights.
351 [Reserved]
352 Structures and improvements.
353 Station equipment.
354 Towers and fixtures.
355 Poles and fixtures.
356 Overhead conductors and devices.
357 Underground conduit.
358 Underground conductors and devices.
359 Roads and trails.
359.1 Asset retirement costs for transmission plant.

4. DISTRIBUTION PLANT

360 Land and land rights.
361 Structures and improvements.
362 Station equipment.
363 Storage battery equipment.
364 Poles, towers and fixtures.
365 Overhead conductors and devices
366 Underground conduit.
367 Underground conductors and devices
368 Line transformers.
369 Services.
370 Meters.
371 Installations on customers' premises
372 Leased property on customers' premises.
373 Street lighting and signal systems.
374 Asset retirement costs for distribution plant.

5. REGIONAL TRANSMISSION AND MARKET OPERATION PLANT

380 Land and land rights.
381 Structures and improvements.
382 Computer hardware.
383 Computer software.
384 Communication Equipment.
385 Miscellaneous Regional Transmission and Market Operation Plant.
386 Asset Retirement Costs for Regional Transmission and Market Operation Plant.
387 [Reserved]

6. GENERAL PLANT

389 Land and land rights.
390 Structures and improvements.
391 Office furniture and equipment.
392 Transportation equipment.
393 Stores equipment.
394 Tools, shop and garage equipment.
395 Laboratory equipment.
396 Power operated equipment.
397 Communication equipment.
398 Miscellaneous equipment.
399 Other tangible property.
399.1 Asset retirement costs for general plant.

Electric Plant Accounts

301 Organization.

This account shall include all fees paid to federal or state governments for the privilege of incorporation and expenditures incident to organizing the corporation, partnership, or other enterprise and putting it into readiness to do business.

ITEMS

1. Cost of obtaining certificates authorizing an enterprise to engage in the public-utility business.
2. Fees and expenses for incorporation
3. Fees and expenses for mergers or consolidations.
4. Office expenses incident to organizing the utility.
5. Stock and minute books and corporate seal.

NOTE A: This account shall not include any discounts upon securities issued or assumed; nor shall it include any costs incident to negotiating loans, selling bonds or other evidences of debt or expenses in connection with the authorization, issuance or sale of capital stock.

NOTE B: Exclude from this account and include in the appropriate expense account the

ITEMS

1. Batteries/Chemical
2. Compressed Air
3. Flywheels
4. Superconducting Magnetic Storage
5. Thermal

364 Poles, towers and fixtures.

This account shall include the cost installed of poles, towers, and appurtenant fixtures used for supporting overhead distribution conductors and service wires.

ITEMS

1. Anchors, head arm, and other guys, including guy guards, guy clamps, strain insulators, pole plates, etc.
2. Brackets.
3. Crossarms and braces.
4. Excavation and backfill, including disposal of excess excavated material.
5. Extension arms.
6. Foundations.
7. Guards.
8. Insulator pins and suspension bolts.
9. Paving.
10. Permits for construction.
11. Pole steps and ladders.
12. Poles, wood, steel, concrete, or other material.
13. Racks complete with insulators.
14. Railings.
15. Reinforcing and stubbing.
16. Settings.
17. Shaving, painting, gaining, roofing, stenciling, and tagging.
18. Towers.
19. Transformer racks and platforms.

365 Overhead conductors and devices.

This account shall include the cost installed of overhead conductors and devices used for distribution purposes.

ITEMS

1. Circuit breakers.
2. Conductors, including insulated and bare wires and cables.
3. Ground wires, clamps, etc.
4. Insulators, including pin, suspension, and other types, and tie wire or clamps.
5. Lightning arresters.
6. Railroad and highway crossing guards.
7. Splices.
8. Switches.
9. Tree trimming, initial cost including the cost of permits therefor.
10. Other line devices.

NOTE: The cost of conductors used solely for street lighting or signal systems shall not be included in this account but in account 373, Street Lighting and Signal Systems.

366 Underground conduit.

This account shall include the cost installed of underground conduit and tunnels used for housing distribution cables or wires.

ITEMS

1. Conduit, concrete, brick and tile, including iron pipe, fiber pipe, Murray duct, and standpipe on pole or tower.
2. Excavation, including shoring, bracing, bridging, backfill, and disposal of excess excavated material.
3. Foundations and settings specially constructed for and not expected to outlast the apparatus for which constructed.
4. Lighting systems.
5. Manholes, concrete or brick, including iron or steel frames and covers, hatchways, gratings, ladders, cable racks and hangers, etc., permanently attached to manholes.
6. Municipal inspection.
7. Pavement disturbed, including cutting and replacing pavement, pavement base, and sidewalks.
8. Permits.
9. Protection of street openings.
10. Removal and relocation of subsurface obstructions.
11. Sewer connections, including drains, traps, tide valves, check valves, etc.
12. Sumps, including pumps.
13. Ventilating equipment.

NOTE: The cost of underground conduit used solely for street lighting or signal systems shall be included in account 373, Street Lighting and Signal Systems.

367 Underground conductors and devices.

This account shall include the cost installed of underground conductors and devices used for distribution purposes.

ITEMS

1. Armored conductors, buried, including insulators, insulating materials, splices, potheads, trenching, etc.
2. Armored conductors, submarine, including insulators, insulating materials, splices in terminal chamber, potheads, etc.
3. Cables in standpipe, including pothead and connection from terminal chamber or manhole to insulators on pole.
4. Circuit breakers.
5. Fireproofing, in connection with any items listed herein.
6. Hollow-core oil-filled cable, including straight or stop joints, pressure tanks, auxiliary air tanks, feeding tanks, terminals, potheads and connections, etc.

show: (1) The services supplied and revenues received from each customer, and (2) the amounts billed by tariff or specified rates.

Operation and Maintenance Expense Chart of Accounts

1. Power Production Expenses

A. Steam Power Generation

Operation

500 Operation supervision and engineering.
501 Fuel.
502 Steam expenses (Major only).
503 Steam from other sources.
504 Steam transferred—Credit.
505 Electric expenses (Major only).
506 Miscellaneous steam power expenses (Major only).
507 Rents.
508 Operation supplies and expenses (Nonmajor only).
509 Allowances.

Maintenance

510 Maintenance supervision and engineering (Major only).
511 Maintenance of structures (Major only).
512 Maintenance of boiler plant (Major only).
513 Maintenance of electric plant (Major only).
514 Maintenance of miscellaneous steam plant (Major only).
515 Maintenance of steam production plant (Nonmajor only).

B. Nuclear Power Generation

Operation

517 Operation supervision and engineering (Major only).
518 Nuclear fuel expense (Major only).
519 Coolants and water (Major only).
520 Steam expenses (Major only).
521 Steam from other sources (Major only).
522 Steam transferred—Credit. (Major only).
523 Electric expenses (Major only).
524 Miscellaneous nuclear power expenses (Major only).
525 Rents (Major only).

Maintenance

528 Maintenance supervision and engineering (Major only).
529 Maintenance of structures (Major only).
530 Maintenance of reactor plant equipment (Major only).
531 Maintenance of electric plant (Major only).
532 Maintenance of miscellaneous nuclear plant (Major only).

C. Hydraulic Power Generation

Operation

535 Operation supervision and engineering.
536 Water for power.
537 Hydraulic expenses (Major only).
538 Electric expenses (Major only).
539 Miscellaneous hydraulic power generation expenses (Major only).
540 Rents.
540.1 Operation supplies and expenses (Nonmajor only).

Maintenance

541 Maintenance supervision and engineering (Major only).
542 Maintenance of structures (Major only).
543 Maintenance of reservoirs, dams and waterways (Major only).
544 Maintenance of electric plant (Major only).
545 Maintenance of miscellaneous hydraulic plant (Major only).
545.1 Maintenance of hydraulic production plant (Nonmajor only).

D. Other Power Generation

Operation

546 Operation supervision and engineering.
547 Fuel.
548 Generation expenses (Major only).
548.1 Operation of Energy Storage Equipment
549 Miscellaneous other power generation expenses (Major only).
550 Rents.
550.1 Operation supplies and expenses (Nonmajor only).

Maintenance

551 Maintenance supervision and engineering (Major only).
552 Maintenance of structures (Major only).
553 Maintenance of generating and electric plant (Major only).
553.1 Maintenance of Energy Storage Equipment
554 Maintenance of miscellaneous other power generation plant (Major only).
554.1 Maintenance of other power production plant (Nonmajor only).

E. Other Power Supply Expenses

555 Purchased power.
555.1 Power Purchased for Storage Operations
556 System control and load dispatching (Major only).
557 Other expenses.

2. Transmission Expenses

Operation

560 Operation supervision and engineering.
561.1 Load dispatch—Reliability.

561.2 Load dispatch—Monitor and operate transmission system.
561.3 Load dispatch—Transmission service and scheduling.
561.4 Scheduling, system control and dispatch services.
561.5 Reliability planning and standards development.
561.6 Transmission service studies.
561.7 Generation interconnection studies.
561.8 Reliability planning and standards development services.
562 Station expenses (Major only).
562.1 Operation of Energy Storage Equipment
563 Overhead line expense (Major only).
564 Underground line expenses (Major only).
565 Transmission of electricity by others (Major only).
566 Miscellaneous transmission expenses (Major only).
567 Rents.
567.1 Operation supplies and expenses (Nonmajor only).

Maintenance

568 Maintenance supervision and engineering (Major only).
569 Maintenance of structures (Major only).
569.1 Maintenance of computer hardware.
569.2 Maintenance of computer software.
569.3 Maintenance of communication equipment.
569.4 Maintenance of miscellaneous regional transmission plant.
570 Maintenance of station equipment (Major only).
570.1 Maintenance of Energy Storage Equipment
571 Maintenance of overhead lines (Major only).
572 Maintenance of underground lines (Major only).
573 Maintenance of miscellaneous transmission plant (Major only).
574 Maintenance of transmission plant (Nonmajor only).

3. REGIONAL MARKET EXPENSES

Operation

575.1 Operation Supervision.
575.2 Day-ahead and real-time market administration.
575.3 Transmission rights market administration.
575.4 Capacity market administration.
575.5 Ancillary services market administration.
575.6 Market monitoring and compliance.
575.7 Market facilitation, monitoring and compliance services.
575.8 Rents.

Maintenance

576.1 Maintenance of structures and improvements.
576.2 Maintenance of computer hardware.
576.3 Maintenance of computer software.
576.4 Maintenance of communication equipment.
576.5 Maintenance of miscellaneous market operation plant.

4. DISTRIBUTION EXPENSES

Operation

580 Operation supervision and engineering.
581 Load dispatching (Major only).
581.1 Line and station expenses (Nonmajor only).
582 Station expenses (Major only).
583 Overhead line expenses (Major only).
584 Underground line expenses (Major only).
584.1 Operation of Energy Storage Equipment
585 Street lighting and signal system expenses.
586 Meter expenses.
587 Customer installations expenses.
588 Miscellaneous distribution expenses.
589 Rents.

Maintenance

590 Maintenance supervision and engineering (Major only).
591 Maintenance of structures (Major only).
592 Maintenance of station equipment (Major only).
592.1 Maintenance of structures and equipment (Nonmajor only).
592.2 Maintenance of Energy Storage Equipment
593 Maintenance of overhead lines (Major only).
594 Maintenance of underground lines (Major only).
594.1 Maintenance of lines (Nonmajor only).
595 Maintenance of line transformers.
596 Maintenance of street lighting and signal systems.
597 Maintenance of meters.
598 Maintenance of miscellaneous distribution plant.

5. CUSTOMER ACCOUNTS EXPENSES

Operation

901 Supervision (Major only).
902 Meter reading expenses.
903 Customer records and collection expenses.
904 Uncollectible accounts.
905 Miscellaneous customer accounts expenses (Major only).

6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES

Operation

906 Customer service and informational expenses (Nonmajor only).
907 Supervision (Major only).

2. Operating supplies, such as lubricants, commutator brushes, water, and rubber goods.
3. Station meter and instrument supplies, such as ink and charts.
4. Station record and report forms.
5. Communication service.
6. First-aid supplies.
7. Tool expense.
8. Transportation expenses.
9. Meals, traveling, and incidental expenses.

568 Maintenance supervision and engineering (Major only).

This account shall include the cost of labor and expenses incurred in the general supervision and direction of maintenance of the transmission system. Direct field supervision of specific jobs shall be charged to the appropriate maintenance account. (See operating expense instruction 1.)

569 Maintenance of structures (Major only).

This account shall include the cost of labor, materials used and expenses incurred in the maintenance of structures, the book cost of which is includible in account 352, Structures and Improvements. (See operating expense instruction 2.)

569.1 Maintenance of Computer Hardware.

This account shall include the cost of labor, materials used and expenses incurred in the maintenance of computer hardware serving the transmission function.

569.2 Maintenance of Computer Software.

This account shall include the cost of labor, materials used and expenses incurred for annual computer software license renewals, annual software update services and the cost of ongoing support for software products serving the transmission function.

ITEMS

1. Telephone support
2. Onsite support
3. Software updates and minor revisions

569.3 Maintenance of Communication Equipment.

This account shall include the cost of labor, materials used and expenses incurred in the maintenance of communication equipment serving the transmission function.

569.4 Maintenance of Miscellaneous Regional Transmission Plant.

This account shall include the cost of labor, materials used and expenses incurred in the maintenance of miscellaneous regional transmission plant serving the transmission function.

570 Maintenance of station equipment (Major only).

This account shall include the cost of labor, materials used and expenses incurred in maintenance of station equipment the book cost of which is includible in account 353, Station Equipment. (See operating expense instruction 2.)

570.1 Maintenance of Energy Storage Equipment

This account shall include the cost of labor, materials used and expenses incurred in the maintenance of energy storage equipment includible in Account 351, Energy Storage Equipment—Transmission, which are not specifically provided for or are readily assignable to other transmission maintenance expense accounts.

571 Maintenance of overhead lines (Major only).

This account shall include the cost of labor, materials used and expenses incurred in maintenance of transmission plant, the book cost of which is includible in accounts 354, Towers and Fixtures, 355, Poles and Fixtures, 356, Overhead Conductors and Devices, 359, Roads and Trails. (See operating expense instruction 2.)

ITEMS

1. Work of the following character on poles, towers and fixtures:
a. Installing or removing additional clamps or strain insulators on guys in place.
b. Moving line or guy pole in relocation of the same pole or section of line.
c. Painting poles, towers, crossarms or pole extensions.
d. Readjusting and changing position of guys or braces.

e. Realigning and straightening poles, cross arms braces, and other pole fixtures.

f. Reconditioning reclaimed pole fixtures.

g. Relocating crossarms, racks, brackets, and other fixtures on poles.

h. Repairing or realigning pins, racks, or brackets.

i. Repairing pole supported platform.

j. Repairs by others to jointly owned poles.

k. Shaving, cutting rot, or treating poles or crossarms in use or salvaged for reuse.

l. Stubbing poles already in service.

m. Supporting fixtures and conductors and transferring them to new pole during poles replacements.

n. Maintenance of pole signs, stencils, tags, etc.

2. Work of the following character on overhead conductors and devices:

a. Overhauling and repairing line cutouts, line switches, line breakers, etc.

b. Cleaning insulators and bushings.

c. Refusing cutouts.

d. Repairing line oil circuit breakers and associated relays and control wiring.

e. Repairing grounds.

f. Resagging, retying, or rearranging position or spacing of conductors.

g. Standing by phones, going to calls, cutting faulty lines clear, or similar activities at times of emergencies.

h. Sampling, testing, changing, purifying, and replenishing insulating oil.

i. Repairing line testing equipment.

j. Transferring loads, switching and reconnecting circuits and equipment for maintenance purposes.

k. Trimming trees and clearing brush.

l. Chemical treatment of right of way areas when occurring subsequent to construction of line.

3. Work of the following character on roads and trails:

a. Repairing roadway, bridges, etc.

b. Trimming trees and brush to maintain previous roadway clearance.

c. Snow removal from roads and trails.

d. Maintenance work on publicly owned roads and trails when done by utility at its expense.

572 Maintenance of underground lines (Major only).

This account shall include the cost of labor, materials used and expenses incurred in maintenance of transmission plant, the book cost of which is includible in accounts 357, Underground Conduit, and 358, Underground Conductors and Devices. (See operating expense instruction 2.)

ITEMS

1. Work of the following character on underground conduit:

a. Cleaning ducts, manholes, and sewer connections.

b. Minor alterations of handholes, manholes, or vaults.

c. Refastening, repairing, or moving racks, ladders, or hangers in manholes, or vaults.

d. Plugging and shelving or replugging ducts.

e. Repairs to sewers and drains, walls and floors, rings and covers.

2. Work of the following character on underground conductors and devices:

a. Repairing oil circuit breakers, switches, cutouts, and control wiring.

b. Repairing grounds.

c. Retraining and reconnecting cables in manhole, including transfer of cables from one duct to another.

d. Repairing conductors and splices.

e. Repairing or moving junction boxes and potheads.

f. Refireproofing of cables and repairing supports.

g. Repairing electrolysis preventive devices for cables.

h. Repairing cable bonding systems.

i. Sampling, testing, changing, purifying and replenishing insulating oil.

j. Transferring loads, switching and reconnecting circuits and equipment for maintenance purposes.

k. Repairing line testing equipment.

l. Repairs to oil or gas equipment in highvoltage cable system and replacement of oil or gas.

573 Maintenance of miscellaneous transmission plant (Major only).

This account shall include the cost of labor, materials used and expenses incurred in maintenance of owned or leased plant which is assignable to transmission operations and is not provided for elsewhere. (See operating expense instruction 2.)

574 Maintenance of transmission plant (Nonmajor only).

This account shall include the cost of labor, materials used and expenses incurred in the maintenance of transmission plant the book cost of which is includible in plant accounts 351 to 359 inclusive. (See operating expense instruction 2.)

ITEMS

1. Work of the following character on poles, towers and fixtures:

a. Installing or removing additional clamps or strain insulators on guys in place.

b. Moving line or guy pole in relocation of the same pole or section of line.

593 Maintenance of overhead lines (Major only).

This account shall include the cost of labor, materials used and expenses incurred in the maintenance of overhead distribution line facilities, the book cost of which is includible in account 364, Poles, Towers and Fixtures, account 365, Overhead Conductors and Devices, and account 369, Services. (See operating expense instruction 2.)

ITEMS

1. Work of the following character on poles, towers, and fixtures:

a. Installing additional clamps or removing clamps or strain insulators on guys in place.

b. Moving line or guy pole in relocation of pole or section of line.

c. Painting poles, towers, crossarms, or pole extensions.

d. Readjusting and changing position of guys or braces.

e. Realigning and straightening poles, crossarms, braces, pins, racks, brackets, and other pole fixtures.

f. Reconditioning reclaimed pole fixtures.

g. Relocating crossarms, racks, brackets, and other fixtures on poles.

h. Repairing pole supported platform.

i. Repairs by others to jointly owned poles.

j. Shaving, cutting rot, or treating poles or crossarms in use or salvaged for reuse.

k. Stubbing poles already in service.

l. Supporting conductors, transformers, and other fixtures and transferring them to new poles during pole replacements.

m. Maintaining pole signs, stencils, tags, etc.

2. Work of the following character on overhead conductors and devices:

a. Overhauling and repairing line cutouts, line switches, line breakers, and capacitor installations.

b. Cleaning insulators and bushings.

c. Refusing line cutouts.

d. Repairing line oil circuit breakers and associated relays and control wiring.

e. Repairing grounds.

f. Resagging, retying, or rearranging position or spacing of conductors.

g. Standing by phones, going to calls, cutting faulty lines clear, or similar activities at times of emergency.

h. Sampling, testing, changing, purifying, and replenishing insulating oil.

i. Transferring loads, switching, and reconnecting circuits and equipment for maintenance purposes.

j. Repairing line testing equipment.

k. Trimming trees and clearing brush.

l. Chemical treatment of right of way area when occurring subsequent to construction of line.

3. Work of the following character on overhead services:

a. Moving position of service either on pole or on customers' premises.

b. Pulling slack in service wire.

c. Retying service wire.

d. Refastening or tightening service bracket.

594 Maintenance of underground lines (Major only).

This account shall include the cost of labor, materials used and expenses incurred in the maintenance of underground distribution line facilities, the book cost of which is includible in account 366, Underground Conduit, account 367, Underground Conductors and Devices, and account 369, Services. (See operating expense instruction 2.)

ITEMS

1. Work of the following character on underground conduit:

a. Cleaning ducts, manholes, and sewer connections.

b. Moving or changing position of conduit or pipe.

c. Minor alterations of handholes, manholes, or vaults.

d. Refastening, repairing, or moving racks, ladders, or hangers in manholes or vaults.

e. Plugging and shelving ducts.

f. Repairs to sewers, drains, walls, and floors, rings and covers.

2. Work of the following character on underground conductors and devices:

a. Repairing circuit breakers, switches, cutouts, network protectors, and associated relays and control wiring.

b. Repairing grounds.

c. Retraining and reconnecting cables in manholes including transfer of cables from one duct to another.

d. Repairing conductors and splices.

e. Repairing or moving junction boxes and potheads.

f. Refireproofing cables and repairing supports.

g. Repairing electrolysis preventive devices for cables.

h. Repairing cable bonding systems.

i. Sampling, testing, changing, purifying and replenishing insulating oil.

j. Transferring loads, switching and reconnecting circuits and equipment for maintenance purposes.

k. Repairing line testing equipment.

l. Repairing oil or gas equipment in high voltage cable systems and replacement of oil or gas.

3. Work of the following character on underground services:

a. Cleaning ducts.

b. Repairing any underground service plant.

594.1 Maintenance of lines (Nonmajor only).

This account shall include the cost of labor, materials used and expenses incurred in the maintenance of distribution line facilities, the book cost of which is includible in account 364, Poles, Towers and Fixtures, account 365, Overhead Conductors and Devices, account 366, Underground Conduit, account 367, Underground Conductors and Devices, and account 369, Services. (See operating expense instruction 2.)

ITEMS

1. Work of the following character on poles, towers, and fixtures:
a. Installing additional clamps or removing clamps or strain insulators on guys in place.
b. Moving line or guy pole in relocation of pole or section of line.
c. Painting poles, towers, crossarms, or pole extensions.
d. Readjusting and changing position of guys or braces.
e. Realigning and straightening poles, crossarms, braces, pins, racks, brackets, and other pole fixtures.
f. Reconditioning reclaimed pole fixtures.
g. Relocating crossarms, racks, brackets, and other fixtures on pole.
h. Repairing pole supported platform.
i. Repairs by others to jointly owned poles.
j. Shaving, cutting rot, or treating poles or crossarms in use or salvage for reuse.
k. Stubbing poles already in service.
l. Supporting conductors, transformers, and other fixtures and transferring them to new poles during pole replacement.
m. Maintaining pole signs, stencils, tags, etc.
2. Work of the following character on overhead conductors and devices:
a. Overhauling and repairing line cutouts, line switches, line breakers, and capacitor installations.
b. Cleaning insulators and bushings.
c. Refusing line cutouts.
d. Repairing line oil circuit breakers and associated relays and control wiring.
e. Repairing grounds.
f. Resagging, retying, or rearranging position or spacing of conductors.
g. Standing by phones, going to calls, cutting faulting lines clear, or similar activities at times of emergencies.
h. Sampling, testing, changing, purifying, and replenishing insulating oil.
i. Transferring loads, switching, and reconnecting circuits and equipment for maintenance purposes.
j. Repairing line testing equipment.
k. Trimming trees and clearing brush.
l. Chemical treatment of right of way area when occurring subsequent to construction of line.
3. Work of the following character on underground conduit:
a. Cleaning ducts, manholes, and sewer connections.
b. Moving or changing position of conduit or pipe.
c. Minor alterations of handholes, manholes, or vaults.
d. Refastening, repairing or moving racks, ladders, or hangers in manholes or vaults.
e. Plugging and shelving ducts.
f. Repairs to sewers, drains, walls and floors, rings and covers.
4. Work of the following character on underground conductors and devices:
a. Repairing circuit breakers, switches, cutouts, network protectors, and associated relays and control wiring.
b. Repairing grounds.
c. Retraining and reconnecting cables in manhole including transfer of cables from one duct to another.
d. Repairing conductors and splices.
e. Repairing or moving junction boxes and potheads.
f. Refireproofing cables and repairing supports.
g. Repairing electrolysis preventive devices for cables.
h. Repairing cable bonding systems.
i. Sampling, testing, changing, purifying and replenishing insulating oil.
j. Transferring loads, switching and reconnecting circuits and equipment for maintenance purposes.
k. Repairing line testing equipment.
l. Repairing oil or gas equipment in high voltage cable system and replacement of oil or gas.
5. Work of the following character on services:
a. Moving position of service either on pole or on customers' premises.
b. Pulling slack in service wire.
c. Retying service wire.
d. Refastening or tightening service bracket.
e. Cleaning ducts.

595 Maintenance of line transformers.

This account shall include the cost of labor, materials used and expenses incurred in maintenance of distribution line transformers, the book cost of which is includible in account 368, Line Transformers. (See operating expense instruction 2.)

EXHIBIT 2

FEDERAL ENERGY REGULATORY COMMISSION
Washington, D.C. 20426

In Reply Refer To:
Office of Enforcement
Docket No. FA11-8-000
April 24, 2013

Mr. Harvey L. Wagner
Vice President and Controller
American Transmission Systems, Inc.
76 S. Main St.
Akron, OH 44308

Dear Mr. Wagner:

1. The Division of Audits within the Office of Enforcement (OE) has completed an audit of American Transmission Systems, Inc. (ATSI) for January 1, 2009 through December 31, 2012. The enclosed audit report explains our audit findings and recommendations.

2. On April 10, 2013, you notified us that ATSI understands and accepts our findings and recommendations. A copy of your verbatim response is included as an appendix to this report. I hereby approve the audit findings and recommended corrective actions. Within 30 days of this letter order, ATSI should submit a plan to comply with the corrective actions. ATSI should make quarterly submissions describing how and when it plans to comply with the corrective actions, including dates it has completed each one. The submissions should be made no later than 30 days after the end of each calendar quarter, beginning with the first quarter after this audit report is issued, and continuing until all the corrective actions are completed.

3. The Commission delegated the authority to act on this matter to the Director of OE under 18 C.F.R. § 375.311 (2012). This letter order constitutes final agency action. ATSI may file a request for rehearing with the Commission within 30 days of the date of this order under 18 C.F.R. § 385.713 (2012).

4. This letter order is without prejudice to the Commission’s right to require hereafter any adjustments it may consider proper from additional information that may come to its attention. Also, any instance of noncompliance not addressed herein or that may occur in the future may also be subject to investigation and appropriate remedies.

5. I appreciate the courtesies extended to the auditors. If you have any questions, please contact Mr. Bryan K. Craig, Director and Chief Accountant, Division of Audits at (202) 502-8741.

Sincerely,

Norman C. Bay
Director
Office of Enforcement

Enclosure

Federal Energy Regulatory Commission

Audit of Formula Rates of American Transmission Systems, Inc.

Docket No. FA11-8-000
April 24, 2013

Office of Enforcement
Division of Audits

TABLE OF CONTENTS

I. Executive Summary

A. Overview

The Division of Audits (DA) within the Office of Enforcement of the Federal Energy Regulatory Commission (Commission) has completed an audit of American Transmission Systems, Inc. (ATSI or the Company). The audit objective was to determine whether ATSI complied with: (1) Attachment O of the Midwest Independent Transmission System Operator's (MISO) Open Access Transmission Tariff (OATT); (2) various accounts incorporated into MISO's formula rate transmission tariff; (3) accounting regulations in the Uniform System of Accounts (USofA) at 18 C.F.R. pt. 101;[1] and (4) transactions under the tariff. The audit covered the period from January 1, 2009 to December 31, 2012. During the audit period, ATSI's transmission facilities were under the operational control of MISO through June 1, 2011, at which point the operational control was transferred to PJM Interconnection L.L.C. (PJM).

B. Summary of Compliance Findings

Audit staff's compliance findings are summarized below. Details can be found in section III. Audit staff found three areas of noncompliance related to ATSI's implementation of its rates in the following areas:

1. *SFAS 109 Debt Gross-Up on Utility Plant:* ATSI incorrectly included $12,313,754 of SFAS 109 debt gross-up items related to transmission and general utility plant in Account 303, Miscellaneous Intangible Plant. The SFAS 109 debt gross-up should have been included in the appropriate functional plant accounts to which the gross-up amounts related.

2. *Overstatement of Depreciation on Utility Plant:* ATSI incorrectly recorded amounts related to land and land rights in Account 352, Structures and Improvements, that were required to be recorded in Account 350, Land and Land Rights. Consequently, ATSI erroneously recorded $111,945 of depreciation expense on the land and land rights recorded in Account 352. Although ATSI eventually reclassified the land and rights from Account 352 to Account 350, the misclassification had the effect of improperly increasing billings to wholesale transmission customers through formula rate billings by $111,945.

[1] 18 C.F.R. pt. 101 (2012).

3. *Capitalization Policy for Vegetation Management Costs:* ATSI's accounting policy to capitalize certain vegetation management costs is not consistent with the Commission's accounting regulations.

C. Summary of Recommendations

Audit staff's recommendations to remedy the findings in this report are set forth below. Details can be found in section III. Audit staff recommends ATSI:

1. Submit to audit staff for review correcting journal entries to support the reclassification of all FAS 109 debt gross-up amounts included in Account 303, Miscellaneous Intangible Plant, and the associated accumulated depreciation recorded to Account 111, Accumulated Provision for Amortization of Electric Utility Plant (Major only).

2. Submit to audit staff for review the journal entries to support the retirement costs of $217,783 recorded to Account 111 and Account 303.

3. Establish procedures and controls to ensure ATSI is properly classifying assets to their appropriate plant accounts and properly recording depreciation expense and accumulated depreciation on appropriate assets.

4. Submit to audit staff for review journal entries to correct depreciation expense and accumulated depreciation for overstated amounts, and provide documentation showing the adjustments were run through its 2013 formula rate calculation.

5. Revise its policy for clearing transmission corridors to require expensing vegetation management costs related to maintenance activity regardless of height within or outside of its corridor clearing zone and submit it within 30 days to the Division of Audits.

6. Revise its time codes for affected vegetation management activity to properly reflect the expensing of these activities, as appropriate, and submit to the Division of Audits.

7. Provide training to employees on the revised policy on accounting treatment of costs incurred for these specific vegetation management activities.

D. Compliance and Implementation of Recommendations

Audit staff further recommends that ATSI:

- Submit to audit staff for review ATSI's plans for implementing audit staff's recommendations. ATSI should provide these plans to audit staff within 30 days after the final report in this docket is issued.

- Submit quarterly reports to DA describing ATSI's progress in completing each corrective action recommended in the final audit report in this docket. ATSI should deliver the nonpublic quarterly reports to DA no later than 30 days after the end of each calendar quarter, beginning with the first quarter after the final audit report in this docket is issued, and continuing until ATSI completes all recommended corrective actions.

- Submit copies of ATSI's written policies and procedures developed in response to the recommendations of the final audit report for audit staff's approval in the first quarterly report.

E. American Transmission Systems, Incorporated

ATSI is a wholly owned subsidiary of FirstEnergy Corp. ATSI was established from the consolidation of the ATSI Utilities' transmission assets in 2000.[2] On April 2, 2012, the Company reorganized from a wholly owned subsidiary of FirstEnergy Corp. to a wholly owned subsidiary of Allegheny Energy Transmission, LLC, a wholly owned subsidiary of Allegheny Energy, Inc., which is a wholly owned subsidiary of FirstEnergy Corp. ATSI owns major high-voltage transmission facilities. These facilities consist of approximately 5,800 miles of transmission lines with nominal voltages of 345 kilovolts (kV), 138 kV, and 69 kV. In 2003, the Company transferred operational control of its transmission facilities to MISO. Effective June 1, 2011, the Company transferred operational control of its transmission facilities to PJM.[3]

ATSI is located in Akron, OH. ATSI's transmission system offers gateways into the East via high-capacity ties with PJM through Duquesne Light Company and Allegheny Energy, Inc., into the North through multiple 345 kV high-capacity ties with International Transmission Company and through Cleveland Public Power, and into the South through ties with American Electric Power, Inc. and Dayton Power & Light.

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[2] ATSI Utilities included The Cleveland Electric Illuminating Company, Ohio Edison, the Toledo Edison Company, and the Pennsylvania Power Company.

[3] *American Transmission Systems, Inc.*, 129 FERC ¶ 61,249, at P 1 (2009).

F. Formula Rate

ATSI is a transmission owner that provided network and point-to-point transmission service under the MISO OATT until June 1, 2011. ATSI recovered costs associated with providing these services through the application of a transmission revenue requirement formula under Attachment O of the MISO OATT. This formula included components for ATSI's rate base, which included its net utility plant in service, and the costs of providing service, which included the expenses incurred to operate. The formula also included a component for ATSI's return on rate base, which is the product of rate base and the allowable rate of return. ATSI calculated its allowable rate on return based on its weighted cost of debt and equity. Through this formula, a transmission owner inputs the appropriate account balances from its FERC Form No. 1 to calculate the network and point-to-point rate for the upcoming year. The formula rate is calculated on or before May 1 of each year based on data from the previous year.

Effective June 1, 2011, ATSI began recovering its transmission revenue requirement under the PJM OATT, which is generally based on ATSI's prior formula rate template set forth in Attachment O to the MISO OATT.

II. Introduction

A. Objectives

The audit objectives were to determine whether ATSI complied with the: (1) Attachment O of the MISO OATT; (2) various accounts incorporated into the formula rate transmission tariff; (3) accounting regulations contained in the Uniform System of Accounts in 18 C.F.R. pt. 101; and (4) transactions under the tariff.

B. Scope and Methodology

The audit covered the period from January 1, 2009 through December 31, 2012. Audit staff tested the validity of ATSI's formula rates and recovery of transmission charges from transmission customers through the Attachment O formula rate and review of account balances such as revenues, utility plant, taxes, operation and maintenance expenses, and administrative and general expenses by the issuance of formal and informal data requests, review of materials on file with the Commission, and interviews with ATSI employees. Specifically, audit staff:

- Prior to commencement of the audit on November 23, 2010, reviewed publicly available materials, including the FERC Form No. 1, Electric Quarterly Reports (EQRs), and Annual Report to Stockholders. Audit staff also obtained formula rate tariffs; analyzed transmission revenues and plant balances; evaluated fluctuations of account balances; and reviewed other events that would affect formula rate customers.

- Conducted conference calls with Company employees, including its accountants, energy analysts, assistant controller, corporate counsel, and attorneys to better understand how ATSI computed its formula rate.

- Reviewed governing tariffs and rate schedules to ensure ATSI calculated its transmission revenue requirement under the formula in the tariffs and rate schedules.

- Created a year-to-year analysis of ATSI's 2008 and 2009 FERC Form No. 1s documenting any large variances in accounts, specifically focusing on accounts included in ATSI's formula rate calculations.

- Verified that data used in ATSI's formula rate calculation was consistent with the associated FERC Form No. 1 data.

- Evaluated whether ATSI's accounting policies, practices, and procedures were consistent with the USofA.

- Verified all utility plant balances by reviewing construction work orders related to additions and retirements of utility plant, adjustments to utility plant, and general ledger utility plant detail.

- Selected and analyzed work order detail related to additions and retirements of utility plant.

- Analyzed the 2009 general ledger detail of each account included in ATSI's 2010 transmission formula rate calculations to ensure only appropriate costs were included.

- Ensured all general ledger detail for each account tied to the FERC Form No. 1 balances for 2009 and 2010.

- Reviewed and recalculated 2009 depreciation expense and accumulated depreciation on all utility plant assets.

- Verified accuracy of the $59 million in deferred vegetation enhanced management project costs charged to Account 182.3, Other Regulatory Assets.

- Reviewed third-party labor charges and timesheets to ensure labor was properly expensed or capitalized based on project type.

- Tested the accuracy of ATSI's formula rate calculation.

- Documented the Company's culture of compliance including relevant manuals policies, procedures, and functions.

- Interviewed employees, particularly those working in audit focus areas to learn about the processes and procedures.

- Tested aspects of the Company's compliance programs and associated procedures as applicable to determine whether programs were adequate to demonstrate a culture of compliance.

III. Findings and Recommendations

1. SFAS 109 Debt Gross-Up on Utility Plant

ATSI incorrectly included $12,313,754 of SFAS 109 debt gross-up items related to transmission and general utility plant in Account 303, Miscellaneous Intangible Plant. The SFAS 109 debt gross-up should have been included in the appropriate functional plant accounts to which the gross-up amounts related.

Pertinent Guidance

The Chief Accountant's guidance on accounting for income taxes states in part:

> 7. ADJUSTING NET OF TAX COMPONENTS OF UTILITY PLANT
>
> Question: Upon initial application of SFAS 109, an entity must adjust any net of tax components of construction work in progress and plant in service. How should an entity account for these adjustments?
>
> Response: Entities that previously accounted for certain components of plant cost on a net of tax basis, primarily the borrowed funds component of AFUDC, have effectively recorded the deferred income tax effects of those components directly in the plant accounts. The deferred income taxes were computed using the income tax rates in effect when the items were capitalized.
>
> For construction-work-in-progress, an entity shall transfer the deferred income taxes actually included therein to Account 282, Accumulated Deferred Income Taxes - Other Property. . . .
>
> Similar accounting is to be followed for plant-in-service when the required information is available. However, to properly adjust the plant-in-service account an entity will need to determine the specific amounts of borrowed funds and equity AFUDC capitalized in prior periods, the extent to which those amounts and other net-of-tax components have been depreciated, the specific property units to which the amounts have been assigned and the extent to which property retirements affect the accounts in which the income tax effects now reside. In virtually all instances that information will simply not be available or will be too costly to develop. In that situation, an entity shall not adjust the plant-in-service accounts based on estimates or presumed relationships. Instead, an alternate method shall be used to determine the necessary adjustments.

> Under the alternate method, any difference between the reported amount and the tax basis of plant is a temporary difference for which a deferred tax liability shall be recorded in Account 282. If, as a result of action by a regulator, it is probable that amounts required for settlement of that deferred tax liability will be recovered from customers through future rates, a regulatory asset equal to that probable future revenue should be recorded in Account 182.3. That asset is also a temporary difference for which a deferred tax liability shall be recognized in Account 283, Accumulated Deferred Income Taxes – Other.[4]

18 C.F.R. § 125.2(g)(1), governing the schedule of records and periods of retention states:

> Records related to plant in service must be retained until the facilities are permanently removed from utility service, all removal and restoration activities are completed, and all costs are retired from the accounting records unless accounting adjustments resulting from reclassification and original costs studies have been approved by the regulatory commission having jurisdiction. If the plant is sold, the associated records or copies thereof must be transferred to the new owners.

Background

The Financial Accounting Standards Board issued SFAS 109 in 1992, which discontinued accounting for utility plant assets on a net of tax basis, among other matters. This net of tax accounting effectively recorded the deferred income tax effects of utility plant assets directly in the plant accounts. The components of utility plant assets that were accounted for on a net of tax basis primarily related to the debt component of the allowance for funds used during construction (AFUDC). In 1993, the Chief Accountant issued guidance instructing jurisdictional entities how to transfer the deferred income tax effects of those components to Account 282, Accumulated Deferred Income Taxes - Other Property. The removal of the deferred income taxes from utility plant accounts is referred to herein as SFAS 109 debt gross-up.

Audit staff's analysis of ATSI's general ledger for electric plant in service identified $12,313,754 recorded in Account 303 classified as SFAS 109 debt-gross up items. ATSI stated that these amounts were transferred to them on September 1, 2000 as a result of an intra-company transfer of ownership and operational control of jurisdictional transmission facilities from Ohio Edison, The Cleveland Illuminating

[4] *FERC*, Docket No. AI93-5-000, at 6 (April 23, 1993) (delegated letter order).

Company, Pennsylvania Power Company, and Toledo Edison Company to ATSI.[5] Audit staff requested support for SFAS 109 debt gross-up amounts to determine if the amounts were accounted for consistent with the accounting guidance letter issued by the Chief Accountant. Audit staff asked why these SFAS 109 debt gross-up amounts were recorded in Account 303, and how ATSI tied these amounts to an appropriate, specific asset. Finally, audit staff sought to know how ATSI treated these SFAS 109 amounts upon retirement of the appropriate, specific asset to which these amounts were tied.

Initially, ATSI stated that SFAS 109 debt gross-up amounts were not identifiable to specific assets when SFAS 109 was adopted; therefore, they were recorded as intangible assets in Account 303. Audit staff informed ATSI that upon adoption of SFAS 109, the Chief Accountant provided specific guidance on how to account for the SFAS 109 debt gross-up amounts (i.e., the deferred income liability) in utility plant accounts. For utility plant in service, the Chief Accountant stated that to properly adjust the plant in service accounts an entity would need to determine the specific amounts of borrowed funds and equity AFUDC capitalized in prior periods, the extent to which those amounts were depreciated, specific property units affected, and whether retirements have affected the account in which the income tax effects now reside. When the required information is available, an entity should transfer the deferred income liability actually included in the utility plant account to Account 282. Alternatively, when the required information is not available, the deferred tax liability should be recorded in Account 282 and Account 182.3, Other Regulatory Assets, if it is probable that the amounts required for settlement of that deferred tax liability will be recovered from customers through future rates.

ATSI then performed an internal review of its SFAS 109 debt gross-up amounts recorded in Account 303 and acquired the required information necessary to record the SFAS 109 debt gross-up amounts in utility plant accounts. It identified specific tangible property related to SFAS 109 amounts, and determined if any of the specific tangible assets had been retired based on its plant records. Through this review, ATSI identified that $217,783 of the gross SFAS 109 debt gross-up amounts were associated with tangible property that had been retired. The Company retired this amount by debiting Account 111 and crediting Account 303. The Company also reclassified SFAS 109 debt gross-up amounts of $12,313,754 by debiting the appropriate transmission and general plant accounts, and crediting Account 303. Finally, the remaining balance in Account 111 related to the SFAS 109 debt gross-up of $10,396,768 was transferred to Account 108, Accumulated Provision for Depreciation of Electric Utility Plant.

Audit staff is encouraged that ATSI eventually was able to properly classify the SFAS 109 debt gross-up items in accordance with the Chief Accountant guidance letter. However, audit staff is concerned that this internal review was not undertaken until this

[5] *FirstEnergy Operating Cos.*, 89 FERC ¶ 61,090 (1999).

audit had commenced, even though the transmission facilities were transferred to ATSI in 2000.

Recommendations

We recommend that ATSI:

1. Submit to audit staff for review correcting journal entries to support the reclassification of all SFAS 109 debt gross-up amounts included in Account 303, Miscellaneous Intangible Plant, and the associated accumulated depreciation recorded to Account 111, Accumulated Provision for Amortization of Electric Utility Plant (Major only).

2. Submit to audit staff for review the journal entries to support the retirement costs of $217,783 recorded to Account 111 and Account 303.

2. Overstatement of Depreciation on Utility Plant

ATSI incorrectly recorded amounts related to land and land rights in Account 352, Structures and Improvements, that were required to be recorded in Account 350, Land and Land Rights. Consequently, ATSI erroneously recorded $111,945 of depreciation expense on the land and land rights recorded in Account 352. Although ATSI eventually reclassified the land and rights from Account 352 to Account 350, the misclassification had the effect of improperly increasing billings to wholesale transmission customers through formula rate billings by $111,945.

Pertinent Guidance

Under U.S. Generally Accepted Accounting Principles, land is considered an indefinite-lived asset; therefore, it is not depreciable.[6]

18 C.F.R. pt. 101, Account 350, Land and Land Rights, states, "[t]his account shall include cost of land and land rights used in connection with transmission operations."

18 C.F.R. pt. 101, Account 352, Structures and Improvements, states, "[t]his account shall include the cost in place of structures and improvements used in connection with transmission operations."

Background

Based on the Commission's accounting regulations, land and land rights are properly recorded in Account 350. Land is not depreciated because it has an indefinite life whereas other utility plant assets have a certain depreciable life that is exhausted through determining the depreciation amount over the life of the asset. In 2004, ATSI incorrectly recorded land and land rights in Account 352 that are required to be recorded in Account 350. Consequently, the land and land rights were incorrectly depreciated from 2004 through 2008. During that time, ATSI generated depreciation expense on these land and land rights totaling $111,945 and recovered those amounts through its formula rate billings. In September 2008, ATSI sought to correct its accounting and transferred the land and land rights from Account 352 to Account 350. As a result of this transfer, ATSI assigned the associated accumulated depreciation recorded in Account 108, Accumulated Provision for Depreciation of Electric Utility Plant, to Account 350. This resulted in an accumulated reserve balance of $111,945 erroneously assigned to Account 350.

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[6] Financial Accounting Standards Board (FASB), *Accounting Standards Codification* 360, *Property, Plant, and Equipment*.

In December 2009, ATSI recognized that it was not appropriate to have an accumulated depreciation balance associated with its nondepreciable land and land rights in Account 350. Therefore, it re-assigned the accumulated depreciation balance of $111,945 from Account 350 to Account 352. After audit staff's analysis, ATSI realized that the proper correction would have been to reverse the depreciation expense and accumulated depreciation since land and land rights should not have been depreciated. The $111,945 was included as part of the depreciation expense and accumulated depreciation components in ATSI's formula rate calculation. ATSI indicated it would make appropriate reversing entries for depreciation generated in years 2004 through 2008. The adjusting entries will result in a debit to Account 108, and a credit to Account 403, Depreciation Expense, for $111,945 and will be reflected in ATSI's 2013 formula rate informational filing through its depreciation expense and accumulated depreciation components.

Audit staff agrees that ATSI needs to make the appropriate correcting accounting entries to ensure that the $111,945 is reflected in billings to wholesale transmission customers.

Recommendations

We recommend that ATSI:

3. Establish procedures and controls to ensure ATSI is properly classifying assets to their appropriate plant account and properly recording depreciation expense and accumulated depreciation on appropriate assets.

4. Submit to audit staff for review correcting journal entries to correct depreciation expense and accumulated depreciation for overstated amounts, and provide documentation showing the adjustments were run through its 2013 formula rate calculation.

3. Capitalization Policy for Vegetation Management Costs

ATSI's accounting policy to capitalize certain vegetation management costs is not consistent with the Commission's accounting regulations.

Pertinent Guidance

18 C.F.R. pt. 101, Account 571, Maintenance of Overhead Lines, states, in part, that "[t]his account shall include the cost of labor, materials used, expenses incurred in maintenance of transmission plant, the book cost of which is includable in accounts 354, Towers and Fixtures, 355, Poles and Fixtures, 356, Overhead Conductors and Devices, 359, Roads and Trails." Items listed in this account include trimming trees and clearing brush.

18 C.F.R. pt. 101, Operating Expense Instruction No. 2(A), Maintenance, states, in part, that "[t]he cost of maintenance chargeable to the various operating expense and clearing accounts includes labor, materials, overheads and other expenses incurred in maintenance work." Items listed as maintenance in this instruction include work performed specifically for the purpose of preventing failure, restoring serviceability, or maintaining the life of plant.

18 C.F.R. pt. 101, Electric Plant Instruction No. 3(A), Components of Construction Costs, states in part, "[f]or major utilities, the cost of construction properly includible in the electric plant accounts shall include, where applicable, the direct and overhead costs as listed and defined hereunder." Some of the costs listed include contract work, labor, materials and supplies, and transportation.

Background

During the audit, ATSI provided audit staff with its vegetation management policy for accounting for the clearing of transmission and distribution corridors. Its policy defines the guidelines for accounting for the clearing of transmission and distribution corridors and how to delineate those expenditures that are to be capitalized or expensed. In addition, ATSI provided a diagram illustrating its corridor and the application of its policy as it relates to its clearing zones.

ATSI's vegetation management policy stated, "Costs incurred in connection with the initial clearing and grading of land associated with the construction of transmission and distribution facilities, as well as increasing the horizontal and vertical corridors, shall be capitalized and depreciated." It goes on to state, "expenditures associated with the subsequent removal of priority trees or other large tree limbs outside the corridor shall be capitalized." ATSI's policy further states that, "The removal of tree limbs that overhang at the height 15 feet or more above conductors with voltages below 115 kV and which emanate from trees growing within the corridor shall be capitalized. If in the process of directionally pruning the overhang of 15 feet or higher, it becomes necessary to remove the entire tree, the tree removal costs shall be capitalized." In its responses, ATSI also stated it capitalizes the cutting of tree branches outside the 15-foot corridor clearing zone.

Under this policy, ATSI stated that it would capitalize vegetation management costs not associated with new construction that are related to the expansion of existing corridors, first time tree trimming around existing poles and lines with voltages 115 kV and below, and the removal of danger trees located off existing transmission corridors. ATSI stated that capitalization of first-time tree trimming costs around existing poles and lines complied with FirstEnergy's vegetation management program and accounting policies as well as a state mandate to maintain reliable and safe service. It did not do so to meet certain reliability standards.

The Company stated that it would capitalize the expansion of its existing corridors and removal of danger trees because its existing corridors had not been cleared to the typical right-of-way width during initial construction; therefore, making it eligible for expansion. It also stated the expansion of the corridors increased the capability of the overall transmission system by improving the reliability and performance. The expansion supported the transmission system's ability to consistently accommodate demand for greater system power transfer than when initially constructed. In addition, the Company stated that expanding the corridors ensured sufficient conductor clearances and allowed for maximum conductor ratings. Danger tree removal costs were comingled with corridor widening costs, and both activities were considered to be performed outside the previously cleared corridor. ATSI's accounting policy would provide for these vegetation management costs to be recorded in Account 356, Overhead Conductors and Devices.

ATSI also stated the expansion of its corridors improved reliability, decreased vegetation-caused outages, and increased serviceability. It believed the corridor expansions were substantial additions and met the Commission's requirements for capitalization under Electric Plant Instruction 10(C)(1), Additions and Retirements of Electric Plant. The instruction states:

> When a minor item of property which did not previously exist is added to plant, the cost thereof shall be accounted for in the same manner as for the addition of a retirement unit, as set forth in paragraph B(1), above, if a substantial addition results, otherwise the charge shall be to the appropriate maintenance expense account.[7]

[7] 18 C.F.R. pt. 101 (2012).

Audit staff disagrees with ATSI's interpretation that the expansion of the corridors resulted in a substantial addition to the related transmission lines or system. The purpose of a substantial addition is to make the asset more useful, more efficient, of a greater durability, or of a greater capacity.[8] Audit staff finds that while the expansion of corridors may improve reliability by decreasing vegetation-caused outages, it does not directly make the transmission assets or system more useful, more efficient, of a greater durability, or of a greater capacity.

The Commission's regulations provide for the capitalization of vegetation management costs incurred for the initial clearing of land during construction. Also, the Commission's regulations require vegetation management costs incurred subsequent to the construction phase of a project to be expensed. Vegetation management for plant in service are costs to trim trees, remove trees, prune, and clear brush specifically to ensure the reliability of the transmission system by preventing vegetation-caused failures. Under the Commission's accounting regulations, costs of this nature are recorded as maintenance expense.

ATSI has made strides to ensure the performance of its transmission circuits, enhance the availability of its circuits, improve the availability of its transmission lines, and ensure sufficient clearances to enhance reliability for maximum use of its transmission system. The Commission encourages companies to maintain a comprehensive vegetation management program that will continue to allow a company's transmission system to run reliably and meet the needs of its consumers. ATSI can recover prudently incurred vegetation management costs properly recorded in Account 571 through its formula rate tariff. However, ATSI's policy of capitalizing vegetation management costs for expanding its existing corridors, removing danger trees in existing corridors, and removing tree limbs around existing poles and lines is not supported by the Commission's accounting regulations.

Recommendations

We recommend that ATSI:

5. Revise its policy for clearing transmission corridors to require expensing vegetation management costs related to maintenance activity regardless of height within or outside of its corridor clearing zone and submit it within 30 days to the Division of Audits.

[8] *National Fuel Gas Supply Corp.*, Docket No. AC98-11-000, at 1 (June 17, 1998) (delegated letter order).

6. Revise its time codes for affected vegetation management activity to properly reflect the expensing of these activities, as appropriate, and submit to the Division of Audits.

7. Provide training to employees on the revised policy on accounting treatment of costs incurred for these specific vegetation management activities.

IV. Other Matter

1. Formula Rate Recovery of Intangible Plant

ATSI's formula rate under Attachment O of the MISO OATT included templates for calculating rate base components and for calculating cost of service components used to determine transmission formula rate billings. As relevant here, the Attachment O formula rate calculated rate base using gross intangible plant in service, less accumulated amortization related to intangible plant. However, the FERC Form No. 1 reference for the line item that contains accumulated depreciation on general and intangible plant omitted the reference for intangible plant. Also, ATSI's formula rate did not include a line item or a FERC Form No. 1 reference for amortization expense of intangible plant. When ATSI began recovering its transmission revenue requirement under the PJM OATT in June 2011, it adopted a formula rate that is substantially the same formula rate template in Attachment O to the MISO OATT and carried over the same omissions related to intangible plant.

In October 2011, MISO and its transmission owners filed revisions to portions of the Attachment O formula rate, under section 205 of the Federal Power Act (FPA)**,** to clarify the inclusion of intangible plant in the calculation of Attachment O revenue requirements in Docket No. ER12-297-000. The filing parties proposed to clarify the inclusion of intangible plant by adding the appropriate FERC Form No. 1 reference to intangible plant for the line item that contains accumulated depreciation on general and intangible plant. The filing parties also proposed to add the language "and amortization" to the column heading for "Depreciation Expense" and add the language "& Intangible" to the line item for "General" depreciation and amortization expense. Finally, the filing parties proposed to add the appropriate FERC Form No. 1 reference for amortization expense of intangible plant. On December 21, 2011, the Commission accepted MISO's submittal for filing.

During audit fieldwork, audit staff identified that ATSI's formula rate under the PJM OATT continues to have omissions related to intangible plant that were identified and corrected in Docket No. ER12-297-000. Since ATSI now recovers its cost of service based on a formula rate that is substantially the same as the MISO formula rate, it should have made a filing with the Commission under FPA section 205, similar to what MISO and its transmission owners did in ER12-297-000 to address the proper recovery of intangible plant.

Recommendation

Audit staff recommends that ATSI submit a filing with the Commission under FPA section 205 to adopt the revisions related to intangible plant proposed by MISO in Docket No. ER12-297-000 into its formula rate template under the PJM OATT.

FirstEnergy

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Harvey L. Wagner
Vice President, Controller
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April 10, 2013

Mr. Bryan K. Craig
Director and Chief Accountant
Division of Audits
Office of Enforcement
Federal Energy Regulatory Commission
888 First St., N.E.
Washington, D.C. 20426

Re: Docket No. FA11-8-000

Dear Mr. Craig:

We are responding to the March 26, 2013 Draft Audit Report for the audit of American Transmission Systems, Incorporated ("ATSI") evaluating compliance with (1) Attachment O of the Midwest Independent Transmission System Operator, Inc. ("MISO") FERC Electric Tariff ("MISO Tariff")[1]; (2) various accounts incorporated into the Attachment O formula rate; (3) accounting regulations in the Uniform System of Accounts, 18 C.F.R. Part 101; and (4) transactions under the MISO Tariff. The audit period was January 1, 2009 to December 31, 2012.[2]

We appreciate the opportunity to review the Draft Audit Report and to provide these comments. We also appreciate the time taken by the audit staff to discuss their findings and recommendations with us. As a result of these discussions, we understand and accept the audit staff's findings and recommendations in the Draft Audit Report. As discussed below, pending review of any changes that may be made from the Draft Audit Report to the final report, ATSI reserves its rights under 18 C.F.R. § 41.1.

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[1] Open Access Transmission, Energy and Operating Reserve Markets Tariff for the Midwest Independent Transmission System Operator, Inc., FERC Electric Tariff, Volume 1.

[2] Draft Audit Report at 3.

Finding 1: SFAS Debt Gross-Up on Utility Plant

The Draft Audit Report finds that ATSI included $12,313,754 of SFAS 109 debt gross-up items related to transmission and general utility plant in Account 303, Miscellaneous Intangible Plant that should have been included in the appropriate functional plant accounts to which the gross-up amounts relate. These amounts were transferred to ATSI when ATSI assumed ownership and operational control of FERC jurisdictional transmission facilities in September 2000 from Ohio Edison Company, Pennsylvania Power Company, The Cleveland Illuminating Company, and The Toledo Edison Company.[3]

Based on these findings, the Draft Audit Report makes the following recommendations:

> Recommendation 1: Submit to audit staff for review correcting journal entries to support the reclassification of all FAS 109 debt gross-up amounts included in Account 303, Miscellaneous Intangible Plant, and the associated accumulated depreciation recorded to Account 111, Accumulated Provision for Amortization of Electric Utility Plant (Major only).
>
> Recommendation 2: Submit to audit staff for review the journal entries to support the retirement costs of $217,783 recorded to Account 111 and Account 303.

ATSI Response

ATSI agrees with the finding and will submit its correcting journal entries in response to Recommendations 1 and 2 within 10 days after the issuance of the final report.

Finding 2: Overstatement of Depreciation on Utility Plant

The Draft Audit Report finds that ATSI incorrectly recorded amounts related to land and land rights in Account 352, Structures and Improvements, that should have been recorded in Account 350, Land and Land Rights. As a result, the Draft Audit Report finds that ATSI erroneously recorded $111,945 of depreciation expense on the land and land rights recorded in Account 352. The Draft Audit Report concludes that, although ATSI reclassified the land and rights from Account 352 to Account 350, the misclassification had the effect of improperly increasing billings to wholesale transmission customers through formula rate billings by $111,945.[4]

Based on these findings, the Draft Audit Report makes the following recommendations:

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[3] *Id.* at 12-15.

[4] *Id.* at 16-17.

Recommendation 3: Establish procedures and controls to ensure ATSI is properly classifying assets to their appropriate plant account and properly recording depreciation expense and accumulated depreciation on appropriate assets.

Recommendation 4: Submit to audit staff for review correcting journal entries to correct depreciation expense and accumulated depreciation for overstated amounts, and provide documentation showing the adjustments were run through its 2013 formula rate calculation.

ATSI Response

ATSI will enhance current procedures and controls to ensure ATSI is properly classifying assets to their appropriate plant account and properly recording depreciation expense and accumulated depreciation on appropriate assets.

ATSI will submit its correcting journal entries and documentation in response to Recommendation 4 within 10 days after the issuance of the final report. ATSI will provide documentation showing the adjustments were run through its 2013 formula rate calculation within 10 days after the Annual Update for the Rate Year commencing on June 1, 2013 has been filed.

Finding 3: Capitalization Policy for Vegetation Management Costs

The Draft Audit Report finds that the ATSI accounting policy to capitalize certain right-of-way clearing costs is not consistent with the Commission's accounting regulations. The Draft Audit Report concludes that the regulations provide for the capitalization of vegetation management costs incurred for initial clearing of land during construction but that vegetation management costs incurred subsequent to the construction phase of a project must be expensed. As a result, the Draft Audit Report finds that ATSI's policy of capitalizing vegetation management costs for expanding existing corridors, removing dangerous trees in existing corridors, and removing tree limbs around existing poles and lines is not supported by the Commission's accounting regulations.[5]

Based on these findings, the Draft Audit Report makes the following recommendations:

Recommendation 5: Revise ATSI's policy for clearing transmission corridors to require expensing vegetation management costs related to maintenance activity regardless of height within or outside of its corridor clearing zone and submit it within 30 days to the Division of Audits.

[5] *Id.* at 18-20.

Recommendation 6: Revise the time codes for affected vegetation management activity to properly reflect the expensing of these activities, as appropriate, and submit to the Division of Audits.

Recommendation 7: Provide training to employees on the revised policy on accounting treatment of costs incurred for these specific vegetation management activities.

ATSI Response

ATSI strongly disagrees with Finding 3, as described on the Attachment to this letter, but will adopt Recommendations 5, 6 and 7 to expeditiously resolve the issue.

ATSI will revise its policy for clearing transmission corridors to require expensing vegetation management costs related to maintenance activity regardless of height within or outside of its corridor clearing zone. The revised transmission corridor policy will be submitted to the Division of Audits within 30 days after the issuance of the final report.

ATSI will revise the time codes for affected vegetation management activity to properly reflect the expensing of these activities, as appropriate, and submit them to the Division of Audits within 30 days after the issuance of the final report.

ATSI will provide training to employees on the revised policy on accounting treatment of costs incurred for these specific vegetation management activities.

Other Matter: Formula Rate Recovery of Intangible Plant

The Draft Audit Report notes that the ATSI formula rate under Attachment O of the MISO OATT calculated rate base using gross intangible plant in service, less accumulated amortization related to intangible plant. The Draft Audit Report further notes that the FERC Form No. 1 reference for the line item that contains accumulated depreciation on general and intangible plant, however, omitted the reference for intangible plant. In addition, the Draft Audit Report recognizes that the ATSI formula rate did not include a line item or a FERC Form No. 1 reference for amortization expense of intangible plant. After ATSI began operations under the PJM OATT, in June 2011, ATSI adopted a formula rate substantially unchanged from Attachment O of the MISO OATT. The Draft Audit Report observes that in October 2011, MISO and its transmission owners filed, in Docket No. ER12-297-000,[6] revisions to the Attachment O formula rate to clarify the inclusion of intangible plant in the calculation of the Attachment O revenue requirements by adding the appropriate FERC Form No. 1 references to intangible plant and adding language to the formula line descriptions. The Draft Audit Report recommends that ATSI submit a filing with the Commission under FPA Section 205 to adopt the same revisions proposed by MISO.

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[6] *MISO and Midwest ISO Transmission Owners*, Docket No. ER12-297-000 (filed October 31, 2011), accepted by unpublished letter order issued December 21, 2011.

ATSI Response

ATSI agrees that the formula rate should include the annual amortization of intangible plant as a recoverable expense and the accumulated amortization of intangible plant as a rate base deduction. ATSI's 2012 FERC Form No.1, filed on April 5, 2013, includes financial reporting changes, along with descriptive disclosure, to ensure that the Annual Update of the formula rate for the Rate Year commencing on June 1, 2013 appropriately includes these items. Within 90 days after issuance of the final report, ATSI will submit a limited FPA Section 205 filing to specifically include these items in the formula rate so that the financial reporting changes will no longer be necessary in the FERC Form No.1 after the effective date of the limited FPA Section 205 filing.

Conclusion

As detailed in the Draft Audit Report,[7] ATSI will submit to audit staff for review ATSI's plans for implementing audit staff's recommendations. ATSI will provide these plans to audit staff within 30 days after the final report in this docket is issued. ATSI also will submit quarterly reports to the Division of Audits describing ATSI's progress in completing each corrective action recommended in the final audit report in this docket. ATSI will deliver the nonpublic quarterly reports to the Division of Audits no later than 30 days after the end of each calendar quarter, beginning with the first quarter after the final audit report in this docket is issued, and continuing until ATSI completes all recommended corrective actions. Finally, ATSI will submit copies of ATSI's written policies and procedures developed in response to the recommendations of the final audit report for audit staff's approval in the first quarterly report.

On behalf of ATSI, I thank the audit staff for their professionalism and courteous consideration throughout the course of the audit. If you have any questions about this response, please do not hesitate to contact Jon Taylor, who will become Vice President and Controller of ATSI upon my retirement on May 1, 2013.

Sincerely,

Harvey L. Wagner
Vice President and Controller
American Transmission Systems, Incorporated

[7] *Id.* at 5.

Attachment

Under ATSI's vegetation management accounting policy, expenditures associated with the initial clearing of transmission corridors are capitalized. This includes expenditures associated with expanding existing corridors, removing danger trees in existing corridors, and removing tree limbs around existing poles and lines. Expenditures associated with clearing or maintaining existing corridors are expensed. We believe capitalizing costs associated with expanding existing corridors, removing danger trees in existing corridors, and removing tree limbs around existing poles and lines is consistent with Commission accounting guidelines and generally accepted accounting policies (GAAP).

Under Electric Plant Instruction No. 9, Equipment, electric plant should include costs incurred in connection with the first time clearing and grading of land and rights-of-way and the damage costs associated with construction and installation of plant. Furthermore, 18 C.F.R. pt 101, Account 365, Overhead conductors and devices, states that the account shall include costs for items such as tree trimming, initial costs including the costs of permits therefor.

Increasing corridor widths and removing danger trees and tree limbs through additional leveling, clearing and grading is first time clearing and under the definitions discussed above should be capitalized.

ATSI management respectfully disagrees with the Commission's interpretation that tree trimming costs should only be capitalized during the initial construction and installation of plant. These costs are associated with improving right-of-ways and safeguarding property and are consistent with the accounting for improvements as discussed in Electric Plant Instruction No. 8, Structures and Improvements. Additionally, expanding corridors and removing danger trees and limbs form a new, improved corridor that did not previously exist. This is much different than tree trimming necessary for the upkeep of existing corridors, which are recorded as expense in Account 571, maintenance of overhead lines.

Under GAAP, Accounting Standards Codification (ASC) 360, Property, Plant, and Equipment, defines property, plant, and equipment as assets used to create and distribute an entity's products and services and include:

- Land and land improvements
- Buildings
- Machinery and equipment
- Furniture and fixtures

Under ASC 360, costs associated with preparing land for its intended use, such as leveling, grading, and clearing are capitalized as property, plant, and equipment. As discussed above, increasing corridor widths and removing danger trees and tree limbs require additional leveling, clearing and grading and are consistent with property, plant, and equipment under ASC 360.

PricewaterhouseCoopers, LLP, ATSI's independent auditor, has issued unqualified opinions on ATSI's financial statements and has not proposed any adjustments related to our policy over the accounting for vegetation management costs.

ATSI management continues to believe its accounting policy over vegetation management costs is in accordance with Commission guidelines and is required by GAAP.