UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Bangor Hydro-Electric Company	)	Docket No. ER04-157-000
	)	
Central Maine Power Company	)	
	)	
NSTAR Electric & Gas Corporation,	)	
on behalf of its affiliates:	)	
Boston Edison Company	)	
Commonwealth Electric Company	)	
Cambridge Electric Light Company	)	
Canal Electric Company	)	
	)	
New England Power Company	)	
	)	
Northeast Utilities Service Company,	)	
on behalf of its operating company affiliates:	)	
The Connecticut Light and Power Company	)	
Western Massachusetts Electric Company	)	
Public Service Company of New Hampshire	)	
Holyoke Power and Electric Company	)	
Holyoke Water Power Company	)	
	)	
The United Illuminating Company	)	
	)	
Vermont Electric Power Company	)	
	)	
Central Vermont Public Service Corporation	)	
	)	
Green Mountain Power Corporation	)	

MOTION TO INTERVENE, PROTEST AND REQUEST FOR EVIDENTIARY HEARING OF THE NEW ENGLAND CONFERENCE OF PUBLIC UTILITIES COMMISSIONERS

Pursuant to Rules 214 and 211 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("Commission"), 18 C.F.R. §§ 385.211 and 385.214 (2003), the New England Conference of Public Utilities Commissioners ("NECPUC") hereby moves to intervene and submits its protest in the captioned proceeding addressing the November 4, 2003 Joint ROE Filing of New England Transmission Owners Under the RTO New England Open

Access Transmission Tariff ("RTO-NE ROE Filing"). As set forth below, certain aspects of the RTO-NE ROE Filing should be rejected outright as unjust and unreasonable. Further, the Commission should suspend the Transmission Owners' proposed return on equity ("ROE") for the maximum statutory period and set the matter for hearing.

I. EXECUTIVE SUMMARY

The RTO-NE ROE Filing proposes a single ROE to be used in computing the regional and local transmission rates for all the RTO-NE Participating Transmission Owners ("Transmission Owners" or "TOs"). The proposed ROE reflects: (i) a "baseline" ROE of 12.8%; (ii) a 50 basis point adder "for RTO participation;" and (iii) a 100 basis point adder for transmission facilities placed in service after January 1, 2004. For each Transmission Owner, the proposed ROE – even the baseline ROE alone – would represent a significant increase to the allowed transmission ROE. *See* RTO-NE ROE Filing at Attachment 4. There are significant ratemaking, methodological and policy problems with the Transmission Owners' proposal. These flaws warrant rejection of certain aspects of the filing – such as the 50 and 100 basis point adders – and necessitate a hearing to determine the just and reasonable ROE, or ROEs, for the RTO-NE Transmission Owners.

A. The Proposed Baseline ROE Allowance is Excessive.

The Transmission Owners have not demonstrated that their proposed 12.8% baseline ROE is just and reasonable, and accordingly, a hearing is warranted to investigate the just and reasonable ROE for the Owners. As Maine Public Utilities Commission Analyst Richard S. Kivela explains in his affidavit included as Attachment 1 to this filing, a threshold flaw in the baseline ROE proposal is that the proxy group used by the Transmission Owners' witness, William E. Avera, is not representative of the risks of electric transmission companies. In this respect, the growth rates incorporated in the high-side results of Dr. Avera's discounted cash flow ("DCF") analysis, if they could be considered logical at all, are likely driven by the proxy companies' riskier, unregulated investments, and not by the relatively lower risk transmission operations. A reasonable ROE for transmission operations must be based on a more representative proxy group, or, at a minimum, the Commission must recognize the significant risk differentials that exist between Dr. Avera's proxy companies and the Transmission Owners by setting the ROE at the lower end of the proxy group range of returns.

Dr. Avera's analysis is also undermined by his failure to explain his exclusion of proxy companies and results that would tend to produce a lower ROE. Dr. Avera has not, for instance, justified his exclusion of the allegedly "illogical" low-end results in his DCF analysis. Even accepting that it is appropriate to exclude illogically low DCF results, reasoned decisionmaking would also require the exclusion of illogically *high* proxy group ROE results. In this regard, several of the high-side ROE results for Dr. Avera's proxy companies exceed the 14.24% ROE for the S&P 500 calculated by Dr. Avera. Mr. Kivela explains that the notion that a regulated transmission ROE would exceed the average ROE of the S&P 500 is just as "illogical" as the notion that the ROE would be less than a bond yield. Accordingly, the high-end DCF results in Dr. Avera's analysis that exceed 14.24% must be excluded if Dr. Avera's results are used.

Even assuming, *arguendo*, that the Commission is inclined to consider Dr. Avera's proxy group selection and DCF results, the Commission's carefully reasoned natural gas ratemaking precedent and the dictates of reasoned decisionmaking require that the baseline ROE be established using the *median* of the proxy group range of returns rather than the *midpoint* if there are outliers in the range. Use of the midpoint gives inappropriate weight to outliers in a skewed distribution of DCF results. The midpoint of Dr. Avera's proxy group DCF results is severely skewed upward by the inclusion of high-side outliers – particularly the 17.7% high-side result for

PPL Corp. While the Commission has used the midpoint rather than the median in certain electric cases, it has never provided an adequate explanation of why use of the median is appropriate in gas pipeline cases but not electric cases. Indeed, when the Commission's use of the midpoint rather than the median for the Midwest ISO was recently appealed, the Commission implicitly confessed error by asking for a voluntary remand on this issue. Thus, at a minimum, it would be necessary to use the median of Dr. Avera's range of returns rather than the midpoint.

The reliability of Dr. Avera's DCF results are also undermined by the fact that his data do not adequately reflect the downward trend in dividend yields of electric companies as a result of the recent change in the Tax Code to reduce capital gains taxes on corporate dividends. As Mr. Kivela explains, this change is likely to reduce the ROE results in the DCF calculation, and any ROE established for the Transmission Owners must address this significant recent development.

The TOs also present a flawed and incomplete risk analysis in assessing whether a 12.8% baseline ROE is appropriate. Although the TOs and their witnesses repeatedly suggest that the creation of RTO-NE will increase their risks, they have failed to demonstrate that there will be any incremental risks from the creation of RTO-NE that would justify their proposed ROE increases. Further, as noted above, Dr. Avera's ROE fails to recognize the investor consensus that the Transmission Owners' transmission operations face less business risk than the diversified and unregulated operations of the proxy companies, and thus, require a lower ROE than the proxy companies to attract investment.

Dr. Avera's observations about the current investment climate for the electric industry generally, and transmission investment specifically, do not support his recommended ROE. While the last several years may have been turbulent ones for the electric industry, it is beyond dispute that the disruption has been caused primarily by the headline-generating problems in

California, the trouble in the merchant generation sector and the spectacular collapse of Enron. Moreover, even accepting the notion that investment in transmission assets has lagged in recent years, Dr. Avera does not demonstrate that this lag in investment is due to inadequate regulated returns. To the contrary, the impediments to transmission construction likely have more to do with the difficulty in siting, NIMBY issues, and state-federal jurisdictional concerns. The Transmission Owners have failed to demonstrate that a wealth transfer from ratepayers to Transmission Owners will result in the construction of necessary transmission upgrades, or that without this wealth transfer the upgrades will not be built.

Dr. Avera does not even mention the concept of financial risk. It is well-established, however, that in performing a risk analysis to set the ROE within a range of proxy group returns, it is necessary to look at the financial risk of the regulated entity, typically measured by its common equity ratio. A relatively "equity-rich" capital structure signifies less financial risk compared to one containing less common equity. Dr. Avera does not address this important concept, nor does he attempt to determine whether potential financial risk differences between the Transmission Owners and the proxy companies, and between the Transmission Owners themselves, might affect his return recommendation.

Finally, the potential risk differentials among the TOs call into question the reasonableness of a "one size fits all" ROE for all the Transmission Owners. Governing judicial precedent requires the Commission to examine potential risk differentials among the Transmission Owners and justify authorizing the same ROE for each.

B. The Proposed 50 Basis Point Return Adder for Participation in an RTO Contravenes Commission Policy on Incentive Rates and Should Be Rejected.

The Transmission Owners propose a 50 basis point adder to their joint rate of return allowance as an alleged "incentive" for transfer of control of their transmission facilities to the

RTO. The predicate for their filing, however, *i.e.*, "the Commission's policy of recognizing the value of independent operation of transmission facilities," RTO-NE ROE Filing at p. 10, is entirely missing. Commission policy requires that incentives be awarded only prospectively and that they be denied for actions the filing party has already undertaken. The Transmission Owners already turned over operational control of their transmission facilities to the New England Independent System Operator in 1997. Moreover, while the RTO filing removes the aggregate veto by NEPOOL members over ISO actions, it grants individual transmission owners *greater* control over withdrawal from RTO participation, transmission pricing, cost allocation and planning than they have under the current ISO agreement. In these circumstances the adder would constitute a reward for past conduct, which is prohibited under Commission policy, not an incentive for future action.

Assuming, *arguendo*, that an incentive rate solely for the TOs' membership in an RTO is appropriate, the TOs have failed to provide the necessary analysis demonstrating that the benefits to consumers of such proposed incentive policy would outweigh the costs to consumers of the 50 basis point adder the TOs seek. Order No. 2000 made clear that allowing an increased ROE was not to enhance the revenues of transmission owners at the expense of transmission customers. Nor was innovative transmission pricing to take the place of traditional cost-based ratemaking. In fact, the Commission stated that transmission prices must reflect the costs of providing the service. Part of the required filing for an incentive rate, therefore, is a cost-benefit analysis, which includes rate impacts, demonstrating that the incentive rate would provide benefits outweighing its costs. *See* 18 CFR § 35.34(e)(1)(ii).

In support of their filing, the Transmission Owners cite not to the Commission's existing rules and policies governing incentive ratemaking but to (1) a *proposed* Commission policy statement in Docket No. PL03-1 ("Proposed Pricing Policy") and (2) the recent grant of a 50 basis point adder to transmission owner participants in the Midwest Independent System Operator (MISO) RTO (*See* RTO-NE ROE Filing at p. 9) in an order[1] which the Commission has admitted it cannot defend in court and which is the subject of a voluntary remand request by the Commission. *See Public Service Comm'n of the Commonwealth of Kentucky* v. *FERC*, (D.C. Cir. No. 03-1097), "Motion of Respondent FERC to Hold Proceedings in Abeyance and for Voluntary Remand to Permit Issuance of or Further Order" ("FERC Voluntary Remand Motion" (filed December 5, 2003). These are patently inadequate bases to support the TOs' request. Neither a proposed policy, nor an erroneous order provides any basis for approving the requested adder.

C. The Proposed 100 Basis Point Adder for Any New Transmission Placed In Service After December 31, 2003 Contravenes Commission Policy on Incentive Rates and Should Be Rejected.

Citing only (1) an alleged current "severe regional liquidity crunch in New England," *Id.* at p. 17, not tied specifically to transmission financing and (2) the previously-discussed Proposed Pricing Policy, the TOs also propose a 100 basis point adder for new transmission capacity. This proposed major increase simply lacks any substantive support. Most significantly, the proposal lacks the cost-benefit analysis required by the Commission's regulations showing that payment of the incentive will result in some commensurate consumer benefit. In addition it contains the following fatal flaws: (1) it would apply, without qualification, to *all* transmission expansions going into service after December 31, 2003, including transmission projects already planned and commenced, *See* Joint ROE Filing at p. 10, and (2) the projects would qualify for incentive payments simply by virtue of the fact that they involve transmission facilities, *i.e.*, (a)

[1] *Midwest Indep. Transmission Sys. Operator, Inc.*, 100 FERC ¶ 61,292 (2002), *reh'g denied*, 102 FERC ¶ 61,143 (2003) ("Midwest ISO Order")

whether or not the RTO has determined that they are either needed or useful (*e.g.*, to relieve congestion or improve reliability),[2] (b) whether or not they are too costly, (c) whether or not there are better or less expensive non-transmission (or merchant transmission) solutions, (d) irrespective of the fact that the transmission owner may have no discretion but to build the facilities and (e) without differentiation based on the type of technology employed. *Id.* at 17-18. Because the Transmission Owners have failed to provide any valid justification for this adder, it should be rejected.[3]

II. MOTION TO INTERVENE

NECPUC is a not-for-profit corporation comprising public utility commissioners of the States of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont. Formed fifty years ago and funded by the New England states, NECPUC's mission is the promotion of regional cooperation and effective communication on all public utility matters within New England. As a representative of New England's interests concerning the electric industry, NECPUC has a vital stake in the operation of the New England power markets.

The Transmission Owners' proposal to increase their respective ROEs for regional and local transmission rates could have a material effect on the rates paid for electric service in the New England region. Further, the RTO-NE ROE Filing raises important policy questions relative to the proposed formation of RTO-NE and the provision of electric service in New England. Accordingly, NECPUC requests leave to intervene to represent New England's

[2] Under the current ISO and NEPOOL agreements the ISO makes determinations about the need for various transmission projects submitted for ISO review under a Regional Transmission Expansion Plan (RTEP). That process would continue under the RTO proposal, with the RTO producing a Regional System Plan (RSP). The proposal, however, also allows TOs to obtain the new transmission incentive adder even for transmission projects that have not been submitted to the RTO review process.

[3] The Transmission Owners assertion that all transmission is good and useful and therefore should be eligible for the incentive (ROE Filing at 18), does not satisfy their burden of showing that their requested ROE increase is justified.

collective interest in the operation of New England power markets and submits that its participation in this proceeding is in the public interest.

In accordance with Rule 2010, 18 C.F.R. § 385.2010 (2003), NECPUC hereby designates the following persons for service of documents in this proceeding:

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III. PROTEST

A. The Transmission Owners' Proposed Baseline ROE Of 12.8% Is Not Just And Reasonable

The Transmission Owners propose a baseline ROE of 12.8% for their PTF and non-PTF transmission assets under the RTO-NE OATT. *See* RTO-NE ROE Filing at 12. There are fundamental problems with the Transmission Owners' baseline ROE proposal that preclude any finding that the proposal is just and reasonable. The flaws in the Owners' proposal necessitate a hearing to determine the just and reasonable ROE, or ROEs, for the Transmission Owners.

1. The Proxy Groups Used By Dr. Avera Are Not Representative Of The Risk Profiles Of The Participating New England Transmission Owners

It is well established that the ROE for a regulated firm "should be commensurate with the returns on investments in other enterprises having corresponding risks." *FPC v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944). In order to effectuate this principal when the ROE is established with reference to the returns of a proxy group of companies, the Commission must justify its selection of proxy companies by "considering and examining" relevant factors, such as whether the surrogate and at-issue enterprises "share common risks." *Pacific Gas and Elec. Co. v. FERC*, 306 F.3d 1112, 1120-21 (D.C. Cir. 2002); *see also System Energy Resources, Inc.*, Opinion No. 446-A, 96 FERC ¶ 61,165 at 61,732-33, n.20 (2001) (declining to rely exclusively on proxy group that did not include companies similar to the utility for which ROE was being established); *Consumers Energy Co.*, 98 FERC ¶ 61,333 at 62,411 (2002) (affirming Initial Decision that rejected proxy group that included unrepresentative companies); Attachment 1 at ¶ 6.

Here, Dr. Avera applied DCF analyses to four separate proxy groups: (i) a proxy group of twelve transmission owning companies located in the Northeast ("Northeast TO Proxy Group"); (ii) proxy groups comprising Moody's and Standard & Poor's ("S&P") Electric Utilities groups, respectively, provided the companies satisfied minimum business ranking profiles; and (iii) a proxy group of natural gas transmission companies. *See* Exh. NETOs-1 at 28-29, 31-32, 35-36. Dr. Avera also derived an ROE estimate for the S&P 500. *Id.* at 38. Dr. Avera's analysis focuses primarily on the Northeast TO Proxy Group, and his specific ROE recommendation is the midpoint of his adjusted range of returns for this group. *See* Exh. NETO-3 at 1. Given Dr. Avera's principal focus on the Northeast TO Proxy Group, NECPUC's discussion also focuses primarily on that group. NECPUC's concerns regarding the Northeast TO Proxy Group are generally applicable, however, to the often overlapping companies in Dr. Avera's Moody's and S&P proxy groups.[4] *See* Attachment 1 at ¶ 8.

Dr. Avera's Northeast TO Proxy Group consists of the transmission-owning members of RTO-NE, New York Independent System Operator ("NYISO"), and PJM Interconnection,

[4] The Commission should not give any weight to Dr. Avera's gas transmission proxy group or his comparison to the implied ROE for the S&P 500. While there might be some superficial similarities between gas and electric transmission, a myriad of factors distinguish the risk profiles of the two industries, making it inappropriate to rely on gas company proxy groups to set returns for electric utilities. *See Southern Cal. Edison Co.*, Opinion No. 445, 92 FERC ¶ 61,070 at p. 61,265 (2000). Even if the Commission were inclined to give any weight to a gas pipeline proxy group, Dr. Avera's results imply an ROE of 11.6% because the Commission has made clear that use of the median of the range is appropriate using the Commission's gas pipeline DCF methodology. *See, e.g., Northwest Pipeline Corp.*, 99 FERC ¶ 61,305 at p. 62,276 (2002). Reliance on the S&P 500 ROE is patently inappropriate as

L.L.C. ("PJM") that have publicly-traded stock. *See* Exh. NETOs-1 at 28. Dr. Avera excluded otherwise qualified companies that did not pay common dividends or that were not covered by Value Line and/or IBES. *Id.*[5]

The Northeast TO Proxy Group essentially consists of holding companies – parent corporations of the transmission-owning subsidiaries that have placed or will place their assets into RTO-NE, NYISO or PJM. Consequently, before the Commission can reasonably rely upon the DCF results for these companies in setting the ROE for the Transmission Owners, it must compare the proxy companies' risks to those of the transmission business segments that will be operated by RTO-NE. The following chart, prepared by Mr. Kivela, provides a brief overview of the business segment information for the companies in the Northeast TO Proxy Group:

Company	**Business Profile**
Consolidated Edison	95% of 2000 - 2002 revenues were from regulated utility operations. Modest generation holdings.
Constellation Energy Group	54% of 2002 revenues were from regulated utility (Baltimore Gas & Electric). Significant merchant generation holdings (46% of 2002 revenues).
Energy East Corporation	92% of 2000 - 2002 revenues were regulated utility, natural gas LDC in NY, CT, ME and MA, electric in NY, ME and MA. Generation largely divested, with Ginna Nuclear under contract for sale to Constellation. Per *Value Line*, focus is on divesting unregulated operations.
Exelon, Corporation	Heavy investment in Nuclear generation. Per *Value Line*, nuclear generating capacity will exceed 16,000 MW in 2004.
FirstEnergy Corporation	75% of 2002 revenues were from regulated utilities (GPU, Toledo Ed, Ohio Ed and Cleveland Illuminating). Owns nuclear generation. Under scrutiny for August "Blackout."
Northeast Utilities	78% of 2002 revenues were from regulated utilities (CP&L, PSNH, WMECO, Yankee Gas). Owns merchant generation in Select Energy subsidiary.
NSTAR	98% of 2000 - 2002 revenues were from regulated utility operations (electric

the S&P 500, by definition, contains companies spanning virtually every industry segment, and thus does not provide an accurate measure of the ROE necessary for an electric transmission company.

[5] The Northeast TO Proxy Group includes Consolidated Edison, Constellation Energy, Energy East, Exelon Corp., FirstEnergy Corp., Northeast Utilities, NSTAR, Pepco Holdings, PPL Corp., PS Enterprise Group, UGI Corp., and UIL Holdings. *See* Exh. NETOs-3 at 1. Excluded from the group were Bangor Hydro-Electric Co., National Grid USA, Vermont Electric Power Co. (and associated Vermont utilities), CH Energy Group, National Grid Transco PLC and Allegheny Energy, Inc. *Id.* at Exh. NETOs-1, p. 1.

	and natural gas in MA). Generation has been divested.
Pepco Holdings	59% of 2002 revenues were from regulated utilities (Delmarva, Atlantic City Electric, Potomac Electric). Approximately 15% of property & plant invested in generation assets at FYE 2002.
PPL Corporation	Heavy investment in generation in US and abroad. 68% of 2002 revenues were from regulated utilities in PA. Per *Value Line*, most of PPL's "earnings uncertainty lies with its international distribution."
PSEG	Heavy investment in generation in US and abroad. Was 42% of balance sheet at FYE 2002. Per *Value Line*, generating capacity currently exceeds 14,000 MW. 76% of 2001-2002 revenues were from regulated NJ gas and electric utility. Also a constructs generation projects US and abroad. "Major" energy trading operations per *Value Line*.
UGI Corporation	*Value Line* classifies UGI as Natural Gas LDC utility. 286k Natural Gas customers, 61k electric customers at FYE 2002. Only 23% of 2000-2002 revenues come from these utility customers. Remaining 77% comes from competitive retail distribution of propane to 1.3 million customers
UIL Holdings	80% of 2000 - 2002 revenues were regulated electric utility in CT. Modest merchant generation investment in CT. Unregulated operations currently unprofitable per *Value Line*.

The foregoing summary shows that, despite their collective label, the operations of the Northeast TO Proxy Group companies extend far beyond transmission ownership, into diverse businesses often characterized by greater risk. As Mr. Kivela explains in his affidavit, in financial community investment analyses, issues involving the Northeast TO Proxy Group companies, generation, foreign, and/or non-electric investments figured far more prominently than transmission. *See* Attachment 1 at ¶ 13. In this regard, many of the Northeast TO Proxy Group companies have significant investment in electric generation. The generation portion of the electric utility business has been, and likely will continue to be more risky than the transmission business and, thus, the transmission service provided by the Transmission Owners will be less risky than the generation and other diversified businesses segments of the Northeast TO Proxy Group. *Id.* at ¶ 13. Consequently, the return required by those who invest in the parent companies' diversified businesses does not accurately reflect the return required by those who invest in transmission in the RTO-NE region.

Dr. Avera's proxy group analysis also takes no account of the fact that all of the transmission owners in New England operate under formula rates. This is a signficant omission from his proxy group analysis because, as the Commission has noted, companies with formula rates face materially less risk than those with stated rates. *See, e.g., Northeast Utilities Service Co., (Re Public Service Company of New Hampshire)* 56 FERC ¶ 61,269 at 62,053 (1991); *Indiana & Michigan Power Co.*, 4 FERC ¶ 61,316 at p. 61,739 (1978); *South Carolina Generating Co.*, 40 FERC ¶ 61,116 at p. 61,311 (1987). As the Commission explained in *Indiana and Michigan Power Co., supra*, a cost-of-service tariff :

> Permits immediate recovery of any increase in costs, thus limiting [the utility's] risk and minimizing not only the risk of regulatory lag, but also the risk of disapproval. It will automatically make its allowed rate of return on equity regardless of whether it delivers the power or not. The steady stream of revenues from such an arrangement provides the company with a very real advantage over those utilities not operating under similar cost-of-service tariffs.

4 FERC at 61,739. This risk factor, the Commission has held, justifies a lower return allowance. *Id.*

It has not been shown that it is just or reasonable to base the return for the Transmission Owners – participants in an RTO with a transmission-only business and regulated cost-of-service formula rates – on firms with stated rates or with very substantial generation-related and non-electric risks. The significant problems that arise from using non-representative proxy companies are vividly illustrated by Dr. Avera's results for PPL Corp., which produces the highest DCF result (by far) – 17.7% – in the Northeast TO Proxy Group. *See* Exh. NETOs-3 at 1. PPL Corp. was also included in Dr. Avera's Moody's and S&P proxy groups and produced by far the highest result in each of those groups as well (17.7%). *See* Exhs. NETOs-4 and NETOs-5. PPL, as the high-side outlier, elevates the midpoint of the range in each of Dr. Avera's electric proxy groups to a level well above that indicated by other common measures of central tendency, most notably the median and average.

According to the *Value Line* for PPL published September 5, 2003 (the same edition relied upon by Dr. Avera), PPL is a holding company not only for PPL Utilities "which distributes electricity to about 1.3 million customers in … Pennsylvania," but also for subsidiaries involved with power generation and marketing, and foreign electricity distribution in the United Kingdom and South America. *See* Attachment 1 at ¶ ¶ 11 and 13. *Value Line* indicates that PPL's foreign electricity distribution operations are nearly three times as large by customers served (at 3.5 million customers) than its Pennsylvania operations and that these international operations are the source of "[m]ost of the company's earnings uncertainty. *Id.* at ¶ 13.

The significant differences in business risks between the Transmission Owners and Dr. Avera's proxy groups preclude a finding that the Transmission Owners' proposed baseline ROE is just and reasonable. A reasonable ROE proposal must be based on a more representative proxy group or, at a minimum, the Commission must recognize the significant risk differentials that exist between Dr. Avera's proxy companies and the Transmission Owners by setting the ROE at the lower end of the proxy group range of returns. Accordingly, the Commission should reject the Transmission Owners' request that it decide in the initial order whether their proxy group is appropriate and should set the proxy group issue for hearing.

2. Dr. Avera Fails To Justify The Exclusion Of Low-Side DCF Results And Improperly Failed To Exclude Illogical High-Side Results

Dr. Avera's analysis is also undermined by his unsupported exclusion of proxy companies and low-side results that would tend to produce a lower ROE. *See United States Telephone Ass'n v. FCC*, 188 F.3d 521, 525 (D.C. Cir. 1999) (observing that exclusion of outlying data points must be adequately explained). Dr. Avera has not, for instance, justified his exclusion of the low-side DCF results for Exelon Corp. and UIL Holdings. *See* Exh. NETOs-1 at 34.

Dr. Avera excludes as "illogical" the low-side DCF results for Exelon and UIL Holdings, citing the Commission's decision in *Southern California Edison Co.*, 92 FERC ¶ 61,070 at p. 61,266 (2000). Exh. NETOs-1 at 33-34. The exclusion of these results has the effect of dramatically increasing the midpoint of his proxy group range of returns from 11.9% to 12.8%. *See* Exh. NETOs-3. Dr. Avera excluded these results based on his conclusion that the 6.0% and 6.2% low-side results for Exelon and UIL Holdings, respectively, "fell below the contemporaneous average yield on triple-B public utility bonds of approximately 6.7 percent," and thus "provide little guidance as to the returns investors require from common stock." Exh. NETOs-1 at 34.

Dr. Avera has not demonstrated that the low-side results for Exelon and UIL are "illogical" and should be excluded under Commission policy. First, the *Southern California Edison* case cited by Dr. Avera used A-rated bonds as the benchmark for whether a DCF result should be excluded, not triple-B bonds. *Southern California Edison*, 92 FERC at p. 61,266. As Mr. Kivela notes, Dr. Avera has not shown how he calculated his 6.7% average bond yield. Attachment 1 at ¶ 17. Moreover, a comparison of the "average yield" on utility bonds to the low-side DCF results is not necessarily a reliable method of determining whether the low-side results should be excluded, as there exists the potential for a mismatch between the way the dividend yields used in the DCF are calculated and derivation of the "contemporaneous" bond yields.[6]

While Dr. Avera has not justified the exclusion of the low-end results for Exelon and UIL, NECPUC does not dispute that, conceptually, it is appropriate to exclude illogical results from a DCF range of returns, provided the excluded figures are truly illogical. If values that are shown to be illogically low are excluded, however, reasoned decisionmaking would also require the exclusion of illogically *high* proxy group ROE results. *See Missouri Pub. Serv. Comm'n v. FERC*, 215 F.3d 1, 5 (D.C. Cir. 2000). Here, certain of the values included in Dr. Avera's proxy group are illogically high and should be excluded, regardless of whether the Commission accepts Dr. Avera's elimination of low-side values.

Specifically, Dr. Avera's high-side results for PS Enterprise Group and PPL are 15.5% and 17.7%, respectively. *See* Exh. NETOs-3. These values exceed (in PPL's case, by more than 300 basis points) Dr. Avera's own ROE estimate of 14.24% for the S&P 500. As Mr. Kivela explains in his affidavit, it is simply illogical to think that investors would require an ROE in excess of the S&P 500 ROE to invest in an electric transmission company. Attachment 1 at ¶ 19. Accordingly, the high-end DCF results in Dr. Avera's analysis that exceed 14.24% must be excluded if Dr. Avera's approach is utilized.

There is additional evidence that the 17.7% result for PPL in particular is illogical and should be excluded. For instance, the Commission recently applied a 10.88% ROE in

[6] Critiquing a nearly identical analysis performed by Dr. Avera in Docket No. ER04-156-000, the Eastern Consumer-Owned Systems ("ECOS") explained that the stock prices used in Dr. Avera's dividend yield calculations "appear to have been calculated using a denominator based on the highest price reached during each of the study period's six months." ECOS Protest at 32. As such, ECOS explained, "the low-end DCF results reflect the dividend yield anticipated by those investors who purchased the stock on the day when it reached its highest price of the month. The bond yields to which Avera compares those results, however, are an average that includes both high and low daily bond prices, includes all days of the month. No actual investor faces a choice between buying a stock at the month's highest price and buying a bond at that month's average price. The actual choice is between the actual current stock price and the actual current bond price at the moment of purchase." *Id.*

calculating the fixed costs of a PPL generation subsidiary for purposes of calculating "safe harbor" bids under which the PPL units in congested areas could be eligible to bid and set market-clearing prices at an amount that included fixed and variable cost components. *PPL Wallingford Energy LLC,* 104 FERC ¶ 61,199, PP 5, 15 (2003). In addition, PPL's regulated retail returns are in the mid single digits, according to the September 5, 2003 Value Line for PPL.

Moreover, the 880 basis points separating PPL's low-side and high-side results in Dr. Avera's analysis is an extremely wide range for a single company, with the high-end result almost double the low-side results. This spread results primarily from a wide gap between the Value-Line-based *br + sv* growth estimate and the IBES analyst consensus forecast. This wide divergence between Value Line and IBES results suggests considerable uncertainty about the growth prospects of PPL. Moreover, in a recent Q&A posted on PPL's website, PPL's CEO and CFO indicated that they expected to see 3% to 5% growth in earnings per share for the long term. *See* Attachment 1 at ¶ 21. See also http://www.pplweb.com/. While this is consistent with the IBES's 5% growth estimate in Dr. Avera's analysis, it is much lower than the allegedly "sustainable" 13.3% *br +sv* dividend growth figure that Dr. Avera calculates from *Value Line* data. Exh. NETOs-3. It is illogical to think that PPL could sustain 13.3% dividend growth rate when its own senior management forecasts a 3% to 5% earnings growth over the long-term. *Id.* It is also noteworthy that the same September 5, 2003 Value Line cited by Dr. Avera indicates that it expects future 5-year earnings and dividend growth rates of 6% and 8% respectively. In its December 5, 2003 issue, Value Line reduced those estimate further to 3% and 7%, respectively, based on the Company's own view noted above. *Id.*. Given these various indicia of unreliability, the Commission should conclude that PPL's high-end result of 17.7% in Dr. Avera's analysis is illogical and should be excluded.

One additional point warrants discussion with respect to Dr. Avera's elimination of low-side DCF values, namely Dr. Avera's puzzling data for Exelon. As discussed below, Dr. Avera's dividend yield information for Exelon appears to be erroneous, and substitution of correct information would remove any objection that Exelon's low-side results are illogically low and would, in fact, indicate that Exelon's high-side results are implausibly high. According to Dr. Avera's exhibits, Exelon had a dividend yield of zero during the period of his analysis. *See* Exh. NETOs-3. If Dr. Avera is correct (and assuming Exelon's stock price was not zero), it means that Exelon was not paying a dividend, and, according to Dr. Avera's own methodology, it should have been excluded entirely from the DCF analysis. *See* Exh. NETOs-1 at 28.

As Mr. Kivela explains, however, Exelon *did* pay an annualized common dividend of $2.00 per share during the relevant period. Attachment 1 at ¶ 23. Depending on the mechanics of the dividend yield calculation, Exelon's dividend yield could have ranged between 3.4% and 4.3%. *Id.* When this range of yields is added to its IBES growth rate forecast Dr. Avera's argument that the Exelon low-side results (which would then be 9.5%) are illogical is eliminated. *Id.* By the same token, adding that same 3.4% to 4.3% dividend yield range to the 13.6 *br* + *sv* growth estimate catapults Exelon's high-side result to near or at the top of the range (18.2% by Mr. Kivela's calculation) and raises questions about the logic of retaining this figure in the range of reasonableness. *Id.*

3. If The Commission Were To Accept Dr. Avera's DCF Results, Commission Policy And "Statistical Facts" Require The Use Of The Median Rather Than The Midpoint Of The Range

Assuming, *arguendo*, that the Commission is inclined to consider Dr. Avera's proxy group selection and DCF results, Commission precedent and the dictates of reasoned decisionmaking require that the ROE be established using the *median* of the proxy group range of returns rather than the *midpoint*. Here, the median of Dr. Avera's adjusted Northeast TO Proxy Group range would be 10.2%. Attachment 1 at ¶ 28.

In a line of cases involving natural gas pipelines, FERC has articulated a policy of relying on the median rather than midpoint of a range of proxy group returns. In Opinion No. 414-A, the Commission explained that "by utilizing the median rather than the midpoint of the range, the Commission is giving consideration to more of the companies in the proxy group, rather than only those at the top and bottom. This will lessen the impact of any single proxy company whose ROE is atypically high or low." *Transcontinental Gas Pipe Line Corp.*, Opinion 414-A, 84 FERC ¶ 61,084 at pp. 61,427-5 (1998). In *Trunkline Gas Co.*, Opinion No. 441, 90 FERC ¶ 61,017 at p. 61,108 and n.189 (2000), FERC re-affirmed this policy for the same reason, and made clear that it was one of general applicability to all pipeline cases. In yet another pipeline case, FERC chose to use the median to set the ROE, reasoning that "use of the median to counter the effect of a skewed distribution is appropriate because it is a measure of a central tendency, which would not overweigh the outliers in a skewed distribution." *Williston Basin Interstate Pipeline Co.*, 84 FERC ¶ 61,081 at p. 61,389 (1998). In *Northwest*, 99 FERC at 62,276, FERC strongly endorsed the use of the median, providing an explanation that merits being quoted at length:

> The Commission chooses the median, rather than the midpoint of the range of reasonableness or mean, because it aids the Commission's effort to treat all companies that face average risk equally. *In fact, the laws of statistics support the Commission's use of the median in setting ROE for a company facing average risk* because it has important advantages over the mean and midpoint approaches in determining central tendency.
>
> The median best represents central tendency in a skewed distribution over the mean because the latter is drawn in the direction of the skew more than the median. That is, in a very

> positively skewed distribution, the mean will be higher than the median. In a very negatively skewed distribution, the mean will be lower than the median. These statistical facts make the median an appropriate average to use to represent the typical observation in a skewed distribution because it is less affected by extreme numbers than the mean. Similarly, the median is also less affected by extreme numbers than the midpoint in a skewed distribution. *Since the midpoint is the average of the highest and lowest numbers in the group, it is clearly subject to distortion by extremely high or low values*.

(emphasis added). These cases support the use of the median rather than the midpoint because the median is less affected by extreme numbers in a skewed distribution.

Dr. Avera's proxy group analysis is skewed in the manner that the Commission has clearly said warrants use of the median rather than the midpoint. Attachment 1 at ¶ 27. Dr. Avera's results for the Northeast TO Proxy Group, on their face, are skewed upwards. If one accepts Dr. Avera's proposal to eliminate the low-side results for Exelon Corp. and UIL Holdings, then the first 18 figures in his range increase steadily and gradually from 8.0 to 11.5, with never more than 50 basis points separating one figure from its predecessor. *See* Exh. NETOs-3. Then, the last four results increase dramatically, respectively, by 170 basis points, 40 basis points, 190 basis points, and 220 basis points. *Id.*

Given the accepted approach used in natural gas pipeline cases, and the evidence of skewing in Dr. Avera's proxy group results, use of the median rather than the midpoint is appropriate here. Attachment 1 at ¶ 27. While it is true that that it has used the midpoint in setting the ROE for electric utilities in other cases, in none of those cases did FERC explain what differences existed between gas and electric utilities to justify the different treatment in determining the rate of return. This is in stark contrast to the detailed explanation the Commission provided in support of using the median in *Northwest*. Where FERC treats analogous issues in NGA and FPA cases differently, it is obliged to explain why different approaches to the same issue are justified. *Environmental Action, Inc. v. FERC*, 939 F.2d 1057, 1063 (D.C. Cir. 1991). Here, there is no reasonable basis for such a distinction. FERC's past criticisms of the use of the midpoint have nothing to do with the fact that the cases involved gas pipelines and not electric utilities. The Commission's policy is based on simple mathematics – "statistical facts"[7] – that are just as applicable to electric companies as to gas companies.

Notably, when the Commission's use of the midpoint rather than the median for the Midwest ISO in Docket No. ER02-485-000 was recently appealed to the D.C. Circuit by the Kentucky Public Service Commission and others based on the same objections above, the Commission implicitly confessed error by asking for a voluntary remand on the issue. *See* FERC Voluntary Remand Motion, *supra*.

Use of a midpoint approach here is especially inappropriate because of what the high-end outlier represents. The 17.7% high-end outlier that drives the midpoint for all three of Dr. Avera's electric utility proxy groups is the higher of two values for PPL, which as discussed above, is simply not plausible. Thus, even if the Commission finds that PS Enterprise Group, PPL, and/or Exelon need not be excluded from the proxy group, at a minimum, the skewing effects of the counter-intuitive results for these companies should be mitigated by the use of median rather than the midpoint.

The questions about the reliability of the results for PPL (and perhaps Exelon) point to one other reason to use the median. In each of Dr. Avera's electric proxy groups, PPL's high-side result is the highest figure in the range, and thus, drives the midpoint calculation. As noted above, the high-side results for PPL (and perhaps Exelon) are produced by the Value-Line forecasts that Dr. Avera used in calculating his 13.3% *br + sv* growth estimate for PPL. *See*

[7] *Northwest*, 99 FERC at 62,276.

NETOs-3. If Exelon's dividend yield is converted, Exelon's 13.6% br + sv growth estimate could produce an ROE estimate as high as 18.2%. Attachment 1 at ¶ 23. Thus, if the Commission accepted Dr. Avera's proposal, the ROE would be based, in large part, on the forecasts of a single investment analyst for a single proxy company. While Value Line is a respected investment analyst company, it still represents the opinion of just one company. The IBES figures, in contrast, are based on the consensus growth projections of numerous analysts. For this reason, the Commission previously has expressed the view that IBES is more reliable than Value Line. *See, e.g., Northwest Pipeline Corp.*, 92 FERC ¶ 61,287 at 62,001 (2000) (noting its earlier holding that "it would be inappropriate to average the IBES data with projections of retained earnings and per share growth from a single source, Value Line. To do so would dilute the industry consensus in the IBES data and give undue weight to the Value Line projections."); *see also Northwest Pipeline Corp.*, 71 FERC ¶ 61,253 at 61,992 (1995). The potential of allowing a single source of information – Value Line – to have such a significant effect on the result – coupled with the other indicia of the unreasonableness of the PPL high-side results, is another reason to use the median rather than the midpoint.

4. Dr. Avera's DCF Data Do Not Adequately Reflect The Recent Downward Trend In Dividend Yields For Electric Companies Caused By Tax Law Changes

On May 28, 2003, President Bush signed the Jobs and Growth Tax Relief Reconciliation Act of 2003, which, among other things, reduced capital gains taxes on dividend payments to individuals by domestic corporations and qualified foreign corporations. *See* Pub. L. No. 108-27, 115 Stat. 752 § 302 (May 28, 2003). As Mr. Kivela explains in his attached affidavit, one effect of this tax law change on electric utilities has been to sharply reduce dividend yields beginning in June 2003. Mr. Kivela explains that this appears to be due to the increased attractiveness from an investment standpoint of dividend-paying stocks, which would tend to drive up the stock price and, assuming no change in the dividend, decrease the dividend yield. Attachment 1 at ¶ 32.

As noted, electric utility dividend yields began to drop in June 2003. Dr. Avera's dividend yields, however, reflect data for March to August 2003, and, thus, three of the months used by Dr. Avera do not reflect the tax law changes. The reliability of Dr. Avera's DCF results are undermined by the fact that his data do not adequately reflect the significant downward trend in dividend yields of electric companies, and any ROE established for the Transmission Owners in this case must address this significant recent development. *Id.* at ¶ 33.

5. The Transmission Owners' Description Of Their Alleged Risk Does Not Justify A Significantly Increased ROE

The Transmission Owners' respective ROEs currently range from 10.25% to 11.80%, with an average of 11.12% and a median of 11.25%. *See* RTO-NE ROE Filing, Att. 4. Thus, even leaving aside the proposed incentive adders, the 12.8% baseline ROE would represent a significant increase for every one of the Transmission Owners. In conjunction with Dr. Avera's flawed DCF analysis, the Transmission Owners purport to justify this level of ROE by pointing to their alleged business risks. The Transmission Owners have failed to demonstrate that an increased ROE is warranted.

The Transmission Owners suggest, without any convincing support, that they will face increased risks as a result of the formation of RTO-NE, summarizing their views as follows:

> Increased risks should translate into an enhanced return. The New England Transmission Owners are willing to take on the risks associated with turning over operational control of their transmission facilities to RTO-NE, which will have greater authority and independence than ISO New England, but believe that these risks must be adequately taken into account in determining an appropriate ROE.

RTO-NE ROE Filing at 12.

The Transmission Owners do not adequately explain why turning over operational control to RTO-NE will increase their risks, if at all, to an extent warranting the substantial ROE increases the Transmission Owners seek. While Mr. Winser suggests that the TO's obligation to build under the RTO-NE proposal will increase business risks, Exh. NETOs-7 at 14, this is purely speculation, as there is no proof that the transmission owners would be any less likely to build upgrades under the current framework than they will be under RTO-NE. In this respect, and as addressed in greater detail in NECPUC's discussion of the proposed 50 basis point adder, there is no reason to believe that the Transmission Owners' transition from participants in ISO-NE to participants in RTO-NE will materially change their risk profiles. *See* Section III. B., *infra*. Indeed, there is reason to believe that the Transmission Owners will face *less* risk under RTO-NE than under the current ISO-NE/NEPOOL regime, inasmuch as the RTO-NE proposal affords less independence to the RTO from transmission owners than the current ISO has. While RTO-NE would have more independence from non-transmission owner stakeholders than ISO-NE, it will have less independence from transmission owners.

The Transmission Owners also seek to justify the ROE increase by pointing to Dr. Avera's discussion of the alleged increased uncertainty and reduced investor confidence in the electric power industry. *See* RTO-NE ROE Filing at 13. The alleged risks and uncertainty discussed by Dr. Avera, however, are due in large part to the California debacle, the trouble in the merchant generation sector and the collapse of Enron. Moreover, even accepting the notion that investment in transmission assets has lagged in recent years, Dr. Avera does not demonstrate that this lag in investment is due to inadequate regulated returns. To the contrary, the impediments to transmission construction likely have more to do with difficulty in siting, NIMBY issues, and state-federal jurisdictional concerns. The TOs have failed to demonstrate that a wealth transfer fro ratepayers to Transmission Owners will result in the construction of necessary transmission upgrades, and that without this wealth transfer, the upgrades will not be built.

6. The Transmission Owners Do Not Address Financial Risk

It is well-established Commission policy that a utility's risk for ROE purposes has two components, business risk and financial risk. *See, e.g., North Carolina Utilities Comm'n. v. FERC*, 42 F.3d 659, 665 (D.C. Cir. 1994). The Commission gauges financial risk with reference to the amount of equity in the utility's capital structure. A more equity-rich capital structure relative to the proxy companies indicates that the utility faces less financial risk than the proxy companies, and, all else being equal, requires a lower equity return to attract investment. *See id.* The Transmission Owners do not address the concept of financial risk or how the capital structures of the individual Owners compare to the proxy companies. Such evidence is important to an evaluation of the risk profile of the Transmission Owners and the appropriate level of ROE.

7. The Transmission Owners Have Not Justified Their "One Size Fits All" ROE Proposal

The Transmission Owners' failure to address financial risk points to another, fundamental flaw in their filing – their proposal to use a single ROE for each Transmission Owner. As discussed above, a utility's ROE should be set with reference to its risk profile relative to the proxy group. The transmission owners' "one size fits all" approach does not address the possibility that differences in risk between the transmission owners themselves might warrant different ROEs among the various companies. In *Pacific Gas and Electric Company v. FERC*, 306 F.3d 1112, 1120-21 (D.C. Cir. 2002), the Court required FERC to provide a reasoned explanation why it would be reasonable simply to use the allowed ROE for Southern California

Edison Company as a proxy in calculating the appropriate ROE for another California ISO participant. The court observed that the Commission would need to address whether the two entities faced common risks and what factors other than "mere geographical proximity" justified equal returns.

Here, FERC is similarly required to ensure that the same ROE is appropriate for all the transmission owners. While the transmission owners attempt to justify use of a single ROE by arguing that they will face similar risk as common participants in RTO-NE (Filing at 12), there may still exist risk differences between the participants that would require different returns, such as differences in financial risk and strength of management. Indeed, the transmission owners seek to turn the risk analysis on its head by arguing that they should all "be permitted to offer comparable returns to potential providers of equity capital to the transmission sector." RTO-NE ROE Filing at 12. The Commission should determine what ROE is required for an investor to invest in a utility given its relative level of risk, not what ROE the utilities should collectively "be permitted to offer." Accordingly, a hearing is required to evaluate whether it is appropriate to use a single ROE for all the transmission owners, or whether differences in risk among the companies justify different levels of return.

8. The Transmission Owners' Comparisons To The Results In Other Cases Support A Lower ROE

The TOs attempt to support their proposed 12.8% baseline ROE by pointing to other recently approved returns. *See* RTO-NE ROE Filing at 12-13. If anything, these comparisons support a baseline ROE *below* 12.8%. Transmission Owners point to the 12.88% ROE authorized for the Midwest ISO transmission owners. *Id.* at 13 (citing *Midwest ISO*, 100 FERC ¶ 61,292 at P 31). First, as explained above, the Commission's has implicitly confessed error in setting the MISO ROE by requesting a voluntary remand of its orders, including the order cited by Transmission Owners. See, FERC Voluntary Remand Motion, *supra*.. Second, as the TOs acknowledge, the baseline ROE that the Commission established for MISO was 12.38%, 42 basis points less than the baseline ROE requested for the RTO-NE Transmission Owners. Thus, even with a 50 basis point adder, the MISO's *total* ROE was only 8 basis points higher than the Transmission Owners' *baseline* ROE.[8] The Midwest ISO – a true start-up RTO with no history of coordinated operation as in New England – should not be considered less risky than the New England Transmission Owners' proposed RTO and require a lower return. Accordingly, the results of the MISO case, to the extent they have any implications for this case at all, suggest that the Transmission Owners 12.8% baseline ROE is overstated.[9]

B. The TOs' Proposal of a 50 Basis Point Adder Incentive Rate for Joining the RTO Should Be Rejected.

The Transmission Owners propose a 50 basis point adder to their joint rate of return allowance as an alleged "incentive" for transfer of control of their transmission facilities to the RTO. The TOs purport to find justification for the adder in "the Commission's policy of recognizing the value of independent operation of transmission facilities." Joint ROE Filing at p. 10. In dubious support of their filing, the TOs cite, not to the Commission's existing rules and policies governing incentive ratemaking, but to (1) a *proposed* Commission policy statement in Docket No. PL03-1[10] and (2) the recent grant of a 50 basis point adder to transmission owner

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[8] This criticism applies equally to the Transmission Owners reliance on the 12.88% total ROE authorized for International Transmission Company. *See* RTO-NE ROE Filing at 13 (citing *ITC Holdings Corp*., 102 FERC ¶ 61,182 at P 68, *order on reh'g*, 104 FERC ¶ 61,033 (2003).

[9] In *PJM*, 104 FERC ¶ 61,124 at P 72 (2003), the Commission rejected the PJM Transmission Owners' effort to simply use the same ROE that the Commission had authorized for the Midwest ISO transmission owners, explaining that the "return allowed in the MISO proceeding was based on a discounted cash-flow (DCF) analysis of a proxy group containing nine MISO transmission owners or their parent corporations. Since the PJM TOs will not be members of MISO, the DCF analysis used in that proceeding does not measure the risks that would be faced by the PJM TOs. A separate DCF analysis would need to be done for the PJM TOs using an appropriate proxy group."

[10] *Proposed Pricing Policy for Efficient Operation and Expansion of Transmission Grid*, 102 FERC ¶ 61,032 (2003) ("Proposed Pricing Policy").

participants in the Midwest Independent System Operator (MISO) RTO in an order[11] (*see* Joint ROE Filing at p. 9) which the Commission has admitted it cannot defend in court and which is the subject of a voluntary remand request by the Commission. *See Public Service Comm'n of the Commonwealth of Kentucky* v. FERC, (D.C. Cir. No. 03-1097), "Motion of Respondent FERC to Hold Proceedings in Abeyance and for Voluntary Remand to Permit Issuance of or Further Order" ("FERC Voluntary Remand Motion" (filed December 5, 2003).

The paucity of precedent for the filing is matched by the lack of substantive support. Conspicuous by their absence from the filing are either (1) a showing or claim that the RTO filing, in fact, results in more "independent operation of transmission facilities" than currently exists in New England or (2) an analysis or other clear substantiation demonstrating that the value of the independent operation the RTO would allegedly bring justifies the size of the incentive return requested. As discussed below, the 50 basis point adder should be rejected because the Transmission Owners have already transferred operational control of their transmission assets to an independent entity, and because they have failed to demonstrate that the additional value, if any, of the RTO they have proposed, merits any incentive return allowance, much less the 50 basis point bonus they have filed to collect.

1. The New England Transmission Owners Cannot Support Their Proposal for a 50 Basis Point Adder on the Grounds That the Adder is Consistent with a Proposed Policy Statement or a Decision the Commission Has Voluntarily Chosen Not to Defend In Court.

Neither the *Proposed Pricing Policy* nor the *Midwest ISO Order* referenced above can provide support for approval of the 50 basis point adder the Transmission Owners seek. It is settled law that even an *adopted* policy statement does not establish a "binding norm." *Pacific Gas and Electric Co. v. FPC,* 506 F.2d 33, 38 (D.C. Cir. 1974). "When the agency applies the

[11] *Midwest Indep. Transmission Sys. Operator, Inc.*, 100 FERC ¶ 61,292 (2002), *reh'g denied,* 102 FERC ¶ 61,143

policy in a particular situation, it must be prepared to support the policy just as if the policy statement had never been issued." Id. "An agency may establish *binding* policy through rulemaking procedures by which it promulgates substantive rules or through adjudications which establish binding precedents." *Id. See also, Sea Robin Pipeline Co.*, 44 FERC ¶61,356 at 62,197 (1988). While a policy statement only announces the Commission's future intentions, a *proposed* policy statement, by definition, does not even rise to that level of commitment. In any event, even if the Commission were free to ignore its existing incentive rate regulations and its currently effective policy statement on the subject, the proposed policy statement on which the TOs rely should not be adopted applied here. NECPUC's filed comments in Docket No. PL03-1 articulated the reasons why that proposed policy statement should be eschewed and it incorporates those comments here.

The Transmission Owners' reliance on the *Midwest ISO Order* fares no better. There, after *rejecting* an incentive rate filing by the MISO transmission owners, the Commission chose, on its own motion, to grant those owners an additional return allowance in its final order on their transmission rate filing. *Midwest Indep. Transmission Sys. Operator, Inc.*, 100 FERC ¶ 61,292 at 62,315 (2002), *reh'g denied*, 102 FERC ¶ 61,143 (2003) ("Midwest ISO Order"). That order was appealed by a number of parties who questioned the basis for that award on grounds similar to those raised here. By early December, after appellants' briefs had been submitted, the Commission determined that it could not defend the order and asked the court for a voluntary remand. *See FERC Voluntary Remand Motion*, *supra*. Plainly, the Transmission Owners cannot rely on that order as support for their proposal in this case.

2. The 50 Basis Point Adder is Not an Appropriate Incentive Since the TOs Have, For Over Six Years, Already Met Their Claimed Predicate for the Additional Return

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(2003) ("Midwest ISO Order")

Allowance: Operational Control of Their Transmission Facilities is Currently in the Hands of an *Independent* System Operator.

The TOs, as noted above, have justified the 50 basis point adder for agreeing to join an RTO entirely on "the Commission's policy of recognizing the value of independent operation of transmission facilities." Joint ROE Filing at p. 10. The problem with this contention is that it runs head on into the Commission's longstanding policy that it will not grant incentives for actions already undertaken. Incentive rates, the Commission has long held, must be prospective because "a 'reward' for past behavior does not induce future efficiency and benefit consumers." *Policy Statement for Incentive Regulation*, 61 FERC ¶ 61,168 at 61,599 (1992) ("Policy Statement for Incentive Regulation"). The fact is, the added "value of independent operation of transmission facilities" has already largely been realized by virtue of (1) the formation of ISO New England and (2) the large-scale divestiture of generation assets by most of the New England transmission owners.

As the Transmission Owners recognize, the New England Independent System Operator, Inc. was formed in 1997. Transmission Owner Filing at 4. In approving ISO New England the Commission found it to meet the Order No. 888 independence criteria governing ISOs. *See New England Power Pool*, 79 FERC ¶61,374 (1997). In subsequent orders, it directed additional changes to enhance ISO New England's independence. *See, e.g. New England Power Pool*, 86 FERC ¶ 61,262 (1998). Significantly, the independence discussed in Order No. 888 is the very "value" the TOs use to justify the incentive allowance they seek. Order No. 2000 amplifies on this. Ownership of generation and other conflicting interests may lead to discriminatory pricing or allocation of capacity by transmission owners. ISOs, by contrast, are entities whose governance and finances are independent from transmission ownership. "The principle of independence is the bedrock upon which the ISO must be built." *Id.* at 31,047; 31,060-61.

Not only has operational control of transmission been separated from transmission ownership in New England since 1997, many New England transmission owners have gone a step further and have divested themselves of generation assets. Ownership of generation by transmission owners has provided the prime incentive for discrimination in the provision of transmission service. Order No. 888, ¶ 30,036 at 31,646 (1996)

The 50 basis point adder, seen in this context, is plainly a reward for past performance, not an inducement for future conduct. "[R]ewards for this past performance would raise customers' cost without providing corresponding benefit." *Policy Statement for Incentive Regulation* at 61599. The TOs no longer need an inducement to transfer their transmission assets to an independent transmission operator and providing them a reward after the fact cannot, by definition, provide them with an *incentive. See, e.g., ISO New England, Inc.*, 96 FERC 61,359 at 62,355 (2001), *aff'd*, *Sithe New England Holdings LLC v. FERC*, No. 01-1933 (1st Cir. October 4, 2002) ("applying [deficiency charge] retroactively would not provide an incentive, since LSEs and others would have already made their decisions."); *New England Power Pool*, 97 FERC 61,039 at 61,480 (2001), *on reh'g*, 98 FERC 61,249 (2002) (concluding that a "proposal cannot provide an incentive to encourage procedures that have already been completed.").

Finally, Transmission Owners cannot reasonably rely on the Commission's statement in Order No. 2000 that members of existing ISOs "should be allowed to seek transmission pricing reform as newly formed RTOs." Order No. 2000 at 31,129. That statement referred to innovative transmission pricing proposals subject to a cost-benefit test. The Commission did not remotely suggest, however, that ISO members should receive an incentive for the simple act of joining an RTO. The Commission recommended, instead, that a case-by-case evaluation of particular incentive rate proposals was appropriate. *See* Order No. 2000 at 31,192. Consistent with that requirement, Order No. 2000 states that applicants for innovative transmission rate treatment must provide a detailed explanation of how any proposed rate treatment would help achieve the goals of Regional Transmission Organizations, including efficient use of and investment in the transmission system and reliability benefits to consumers.[12] Rewarding a transmission owner for something it is already required to do,[13] or would have done anyway,[14] is not permitted under Order No. 2000. In the particular circumstances of the New England ISO, where the TOs have already transferred operational control of their transmission assets to an independent entity and have divested their generation assets, it is clear that an incentive rate for the simple act of joining an RTO is not warranted.

3. Assuming, *Arguendo*, That an Incentive Rate for the TOs' Membership in an RTO Is Appropriate, the TOs Have Completely Failed to Justify the Size of the Incentive.

Assuming, *arguendo*, that an incentive rate solely for the TOs' membership in an RTO is appropriate, the TOs have failed to provide the necessary analysis demonstrating that the benefits to consumers of such proposed incentive policy would outweigh the costs to those consumers of the 50 basis point adder the TOs seek. Order No. 2000 made clear that allowing an increased ROE was not to enhance the revenues of transmission owners at the expense of transmission customers.[15] Nor was innovative transmission pricing to take the place of traditional cost-based

[12] 18 CFR § 35.34 (e)(1)(i) (2001).

[13] *See, e.g.*, *New England Power Pool*, 97 FERC ¶61,093 at 61,477 (2001).("This decision is in the public's interest as it does not unjustly reward NEP for doing what it is supposed to do, *i.e.*, to adequately maintain its facilities in a prudent, cost-effective manner.")

[14] Id. (a "proposal can not provide an incentive to encourage procedures that have already been completed.")

[15] *Regional Transmission Orgs.*, Order No. 2000, 1996-2000 FERC Stats. & Regs., Regs. Preambles ¶ 31,089, at 31,173 (1999), *order on reh'g*, Order No. 2000-A, 1996-2000 FERC Stats. & Regs., Regs. Preambles ¶ 31,092 (2000), *petition for review dismissed, Public Util. District No. 1 of Snohomish County v. FERC*, 272 F.3d 607 (2001). ("Order No. 2000").

ratemaking.[16] In fact, the Commission stated that transmission prices must reflect the costs of providing the service.[17] Part of the required filing for an incentive rate, therefore, is an analysis demonstrating that the incentive rate would provide benefits outweighing its costs. *See* 18 CFR § 35.34(e)(1)(ii).

The TOs have failed to provide such an analysis. Even assuming that formation of an RTO – as proposed by the Transmission Owners[18] -- is still a material benefit, it is plainly less of a benefit than where no ISO exists at all. Most of the utilities in New England have divested themselves of their generating assets and *all* of them have turned operational control of their transmission assets over to ISO New England. These facts do not make New England unique, but they do differentiate New England utilities from those operating in other regions of the country where most generation is still owned by vertically-integrated utilities and where transmission is not under the control of an ISO. These differences are significant and they should be factored into determining the appropriate level of any incentive scheme designed to encourage RTO participation. Indeed, such an approach is necessitated by the Commission's obligation to "see to it that the increase is in fact needed and is no more than is needed for the purpose." *Farmers Union Central Exchange Inc.*, 734 F.2d 1486, 1503 (quoting *City of Detroit*, 230 F.2d at 817.). As the D.C. Circuit has also noted, it is not reasonable to adopt an "industry-wide solution for a problem that exists only in isolated pockets." *AGD*, *supra*, 824 F.2d at 1019 (D.C. Cir. 1987). *See also*, *Williams Natural Gas Co. v. FERC*, 943 F.2d 1320, 1322 (D. C. Cir.

[16] *Id.*

[17] *Id.*

[18] As discussed in Section III. B. 4, *infra*, the RTO proposal in RT04-2 contains a number of restrictions on the RTO's independence that are conditions for participation by the Transmission Owners. While the RTO filing grants the RTO more independence from non-transmission owning stakeholders than the current ISO has, this added independence is offset by the new controls the transmission owners would obtain.

1991). The TOs have failed to provide the data to quantify the costs and benefits of the proposed incentive rate for joining an RTO, and consequently, the Commission should reject such proposal.[19]

4. The Commission Should Deny the Proposed 50 Basis Point Adder for RTO Formation as the Proposed RTO Would Actually Grant The RTO Less Independence from Transmission Owners Than the Current New England ISO Enjoys.

The TOs, NECPUC reiterates, have justified the need for incentive rates for membership in the RTO proposed in Docket No. RT04-2 based on the "value of independent operation of transmission facilities." Joint ROE Filing at p. 10. If, however, the RTO filing does not provide the RTO the requisite independence from the New England Transmission Owners, then the request for an incentive adder based on achievement of such independence fails at the threshold. In fact, it appears that the RTO, at least as proposed, may establish a regional transmission organization with *less* independence from transmission owners than ISO New England currently enjoys.

NECPUC has supported the formation of an RTO and has found a number of positive features in the RTO filing, not least of which is the removal of the veto power over ISO actions that market participants, as a group, now have as members of NEPOOL.[20] See December 8, 2003 Motion to Intervene and Protest of NECPUC in Docket Nos. RT04-2 et al. To be sure, this means that the RTO will enjoy a degree of independence from market participants generally that the ISO does not have. At the same time, however, the RTO filing would *grant* the Transmission Owners significant powers they do not now have under the ISO agreement. It is the "authority to

[19] Although the Transmission owners have failed to meet their burden of demonstrating that there are any increased risks from the transition from ISO to RTO operation of their transmission systems or that the transition to an RTO provides benefits to consumers so as to justify the increased cost that will result from an adder, NECPUC does not rule out the possibility that such a showing in some context could ever be made by an individual transmission owner or group of transmission owners.

act unilaterally," the Commission has stated, that forms "a crucial element of a truly independent ISO." Order No. 2000 at 62,585. Yet, the elaborate *Mobile-Sierra* protections and other conditions built into the RTO will handcuff the RTO's ability to act unilaterally.

For example, under the RTO proposal, the burden will be shifted to the RTO and other parties if a transmission owner seeks to withdraw from the RTO to prove that withdrawal will be contrary to the public interest. The Commission just recently rejected a similar limitation on the PJM RTO. *Pennsylvania-New Jersey-Maryland Interconnection*, 105 FERC ¶ 61,294 at p. 36 (2003). Such a provision gives the TOs untoward leverage. In other words, if a TO does not get its way, it can simply threaten to pull out of the RTO. TOs will also have the principal FPA section 205 rights for cost allocation and rate design and for system planning and expansion. Further, the RTO's flexibility to change from an established framework for the allocation of responsibilities between it and yet to be formed ITCs is limited. *See* NECPUC RTO Protest, *supra*. As currently formulated, the New England ISO's ability to act unilaterally is not curtailed by the existence of such *Mobile-Sierra* provisions. *See, e.g. New England Power Pool*, 79 FERC ¶ 61,374 at 62,590 (1997) (termination of ISO not permitted without prior Commission approval). In this crucial respect then, the New England ISO is actually more independent than the proposed RTO. The Commission should not approve an incentive rate to join an RTO when that RTO's ability to act unilaterally is so significantly curtailed. If the TOs were allowed an incentive rate under their current proposal, they would be rewarded for creating and joining an RTO whose independence from transmission owners – the very predicate for the incentive-- they have significantly stifled.

C. The Commission Should Reject the TOs' Proposed 100 Basis Point Adder Incentive Rate for New Transmission Expansion As the TOs Have Failed to

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[20] NECPUC has long expressed concern that NEPOOL's veto power compromises the ISO's independence. *See, e.g., New England Power Pool*, 90 FERC ¶ 61,168 at 61,537 (2000) and NECPUC protests filed in that proceeding.

Provide the Required Cost-Benefit Analysis and Have Proposed an Incentive That Rewards Past Actions, Contains No Symmetrical Penalties and Fails to Address Legal and Regulatory Impediments and Lower-Cost Alternatives.

Citing only (1) an alleged current "severe regional liquidity crunch in New England," *Id.* at p. 17, not tied specifically to transmission financing and (2) the previously-discussed Proposed Pricing Policy, the TOs propose a 100 basis point adder for new transmission capacity that is dramatic in scope but devoid of substantive support. The proposal lacks the analysis required by the Commission's regulations that payment of the incentive is tied to some commensurate consumer benefit. On the contrary, it would apply, without qualification, to *all* transmission expansions going into service after December 31, 2003, including transmission projects already planned and commenced. *See* Joint ROE Filing at p. 10. The projects would qualify for incentive payments simply by virtue of the fact that they involve transmission facilities, *i.e.*, (a) whether or not the RTO has determined that they are either useful or needed (*e.g.*, to relieve congestion or improve reliability), (b) whether or not they are too costly, (c) whether or not there are better or less expensive non-transmission (or merchant transmission) solutions, (d) irrespective of the fact that the transmission owner may have no discretion but to build the facilities and (e) without differentiation based on the type of technology employed. *Id.* at 17-18.

The Transmission Owners provide no substantive support for their filing. Instead they simply assert that all transmission is good and useful, and that therefore, all transmission expansions, without further showing, should be eligible for the same, extraordinarily generous incentive return allowance. *Id.* at 18. As discussed below, the filing should be rejected because the proposal (a) lacks the required showing of benefits that would result from the adder the TOs would receive, (b) impermissibly applies to transmission that has already been planned, (c) fails to penalize as it rewards, (d) fails to address whether, given existing impediments to some new transmission projects, the incentive payment could simply award TOs for transmission that would have been built without the payment, (e) fails to demonstrate how the incentive addresses the “liquidity crunch” it claims to mitigate; (f) fails to require a demonstration that lower-cost solutions do not exist; (g) and fails to distinguish between transmission expansions required by the RTO and those coming from the TO’s own initiative, and (h) gives TOs greater incentive to exert control over the RTO to disfavor alternatives to transmission expansion.

1. The TOs Did Not Make the Necessary Cost-Benefit Analysis to Justify the Incentive Rate or Ascertain the Appropriate Level of Such Rate.

The TOs have failed to demonstrate and quantify the consumer benefit resulting from the proposed 100 basis point adder for transmission expansions placed into service on or after January 1, 2004. While the TOs justify their proposal based on generalized concerns for encouraging transmission investment, easing access to financing and ensuring reliability, the TOs fail to provide any comparative analysis of the costs and benefits of the proposed incentive rate and the alternative of no incentive payment at all. Like the incentive adder for RTO membership, an incentive adder for new transmission facilities must contain an analysis comparing the rate impacts of the proposed incentive rate to the expected benefits to consumers. *See* 18 CFR §35.34(e)(1)(ii). Order No. 2000 made it clear that an incentive rate must not enhance the revenues of transmission owners at the expense of transmission customers. *See* Order No. 2000 at 31,173. Proof must be supplied that the TOs proposed incentive adder for transmission construction “is no more than is needed for the purpose.” *Farmers Union* at 1503. The TOs fail to provide any analysis to show (a) whether any adder is needed to facilitate new transmission (b) why they chose 100 basis points as the appropriate adder, (c) why another number, less than 100 basis points, is not more appropriate, (d) how exactly a 100 basis point adder would likely benefit future transmission expansion decisions, (e) what the likely cost to transmission customers would be, and (f) how such incentive might affect the implementation of potentially lower cost, non-transmission, solutions.

The TOs simply rely upon the Proposed Pricing Policy for authority to justify the 100 basis point adder. *See* Proposed Pricing Policy ¶ 75. NECPUC has already explained, in the context of the 50 basis point adder, why the Proposed Pricing Policy does not apply and why the Commission's existing regulations and policies must govern the disposition of this case. NECPUC has further explained in its comments on the proposed policy statement (which NECPUC incorporates by reference here) why that policy should not be adopted. However, even in the Proposed Policy Statement, the Commission notes that "additional information would be required" to support why a 100 basis point adder would be needed to encourage investment in new transmission. *Id.*

The "evidence" provided by the TOs makes clear that "100" is simply an arbitrary number. Absent from the filing is the required analysis demonstrating that "100" is needed, but no larger than needed. The TOs have made no showing demonstrating a lack of investment in New England ISO transmission facilities without an adder. Nor have they shown that the specific adder they have proposed is no greater than is necessary to accomplish its purpose.

2. The Proposal Should Not Apply to Projects that the Transmission Owners are Obligated to Build and Transmission Already Planned Prior to January 1, 2004.

The TOs' proposal to grant an incentive adder to *all* transmission expansions put into service on or after January 1, 2004 suffers from exactly the same defect as the 50 basis point adder rewarding Transmission Owners *now* for their *1997* decision to turn control of their transmission facilities to an independent operator. "A properly structured incentive mechanism is prospective and intended to encourage otherwise unanticipated future actions to reduce costs in the future." *Canyon Creek*, 56 FERC ¶ 61,140 at 61,515 (1991). Rewarding a transmission owner for something it is already required to do, or would have done anyway, is not permitted under Order No. 2000. *See, e.g.*, *New England Power Pool*, 97 FERC ¶ 61,093 at 61,477 (2001). In their RTO filing, the Transmission Owners have voluntarily entered into an agreement that requires them, subject to necessary regulatory approvals, to build upgrades included in the Regional System Plan. Thus, an incentive is inappropriate because as part of their proposed RTO arrangement, transmission owners (by their own choice) are already obligated to build transmission.

In addition, the Transmission Owners' proposal would grant an incentive return allowance for transmission that has been planned and/or under construction prior to the existence of the incentive. Assuming that the Commission permits *any* incentive rate for transmission expansion, the incentive should apply only to transmission expansions planned and constructed after the approval of the incentive rate. To hold otherwise would improperly reward TOs for past actions in contravention of longstanding Commission policy.

3. The Incentive Rate Should Also Penalize TOs That Fail to Construct New Transmission Expansions.

A key component of the Commission's 1991 *Policy Statement on Incentive Regulation* was that an incentive rate should not only reward utilities for taking the desired action, the incentive rate should also "penalize utilities that fail to achieve these efficiencies – opportunities for reward should be offset by a symmetric downside risk." *Policy Statement on Incentive Regulation* at 61,590. Consistent with the *Policy Statement on Incentive Regulation, supra,* and assuming a 100 basis point adder for new transmission expansion could be justified, the proposal should also create penalties for TOs that fail to meet their obligation to construct needed transmission or to meet the reliability or congestion-reducing objectives of a proposed expansion project. A transmission adder for all transmission expansions fails to meet this test. It simply rewards any TOs that expand transmission in the RTO and it does so whether or not the expansion is needed or provides any benefit to the region. There is, moreover, no symmetric downside risk to the Transmission Owner at all. The proposal contains no provisions to penalize TOs that fail to construct needed transmission expansions, much less contemplates penalizing Transmission Owners for poor performance or failure to improve reliability. Accordingly, the Commission should reject the new transmission adder as contrary to its existing incentive rate policy.

4. The TOs Have Not Shown That the Proposed Incentive Will Facilitate the Construction of Needed or Beneficial New Transmission that Would Not Have Been Built Otherwise.

In their filing, the TOs identify access to financing as a principal barrier to the construction of new transmission. See Joint ROE Filing at pp. 9, 17. As stated above, they have provided no support for this assertion. Further, they fail to demonstrate whether, or how, the proposed financial incentive rate would promote transmission expansion in light of existing barriers to expansion having nothing to do with access to capital, such as environmental regulations and other siting considerations. This deficiency is fatal to their filing.

The TOs do mention that, by necessity, a TO's ability to construct new transmission is "conditioned upon receipt of required regulatory or legal approvals," but do not factor in such impediments to construction into an analysis of whether the 100 basis point adder will effectively result in the construction of new transmission that is necessary or beneficial to consumers and would otherwise not have been built. Id. at p. 9. If some transmission expansion cannot be built irrespective of incentives, if TOs are under an obligation to build and if the rate of return sans adder is reasonable, *i.e.* sufficient to attract capital under *FPC v. Hope Natural Gas Co.*, 320

U.S. 591 (1944),[21] then, by definition, the adder will simply reward TOs for transmission they would have built anyway. In short, the proposal should be rejected as providing nothing but a windfall to TOs.

5. The Proposed Incentives, Coupled with RTO Provisions Permitting Virtually Unilateral TO Withdrawal from the RTO, May Bias Solutions to Reliability and Congestion Problems.

The TOs state that the proposed incentive is necessary to encourage investment in new transmission. While the need for investment in new transmission is widely recognized as a major concern in RTOs, such concern should not override the central concerns of providing the most efficient allocation of resources such that end-use customers receive the most reliable and lowest cost service. Order No. 2000 evidences the Commission's concern that the most efficient result will not always be transmission expansion. *See* Order No. 2000 at 31,061. Sometimes additional generation or improved demand side management will be the most efficient solutions.

Unfortunately, one combined side effect of the interplay between the TO exit feature of RTO proposal in Docket No. RT04-2 and the transmission expansion incentive adder is that TOs will have both greater incentives and greater leverage to push for transmission solutions to congestion and reliability. As proposed, the TO-RTO arrangement would allow TOs to withdraw from the RTO at any time, subject only to the risk that complainants could surmount a Mobile-Sierra burden to prove that withdrawal would contravene the public interest. If the RTO balked at approving a transmission expansion, the TO would have the leverage to threaten a quick exit. This is problem enough with the exit provision. But the expansion incentive adder exacerbates the problem because the adder will give TOs even greater incentive to push unnecessary projects or to gold plate them.

[21] A reasonable rate of return allowance already permits a utility "a return on its common equity commensurate to that which investors can expect on investments in unregulated companies of comparable risk. Order No. 389, FERC

D. The Commission Should Disregard The Transmission Owners' Efforts to Minimize the Impact of their Proposal on Ratepayers.

The Transmission Owners seek to argue that their proposal will have only a "modest impact" on rates. *See* RTO-NE ROE Filing at 11. Information submitted with the Filing shows that the impact of the rate change will vary by Transmission Owner and customer, generally ranging from 1% up to 22.58%, with the impacts mostly hovering in the 5% to 11% range. *See* RTO-NE ROE Filing at Att. 5. These impacts are not *de minimis* and, in any event, the Commission may not truncate its just and reasonable rate review on the grounds that the proponents assert that the impact is only "modest." *See Farmers Union Cent. Exch. v. FERC*, 734 F.2d 1486, 1508 (D.C. Cir. 1984) (rejecting argument that market-based FERC oil pipeline rates were supported in part by the fact that the price of transportation was dwarfed by commodity cost in overall oil prices). As the Court noted in *Farmers Union*, the Commission's argument did "not excuse deviation from the just and reasonable standard, for not even a little unlawfulness is permitted." *Id.* (internal quotes and citations omitted).

CONCLUSION

For the reasons stated above, the incentive return provisions of the RTO-NE ROE Filing should be rejected outright as unjust and unreasonable. Further, the Commission should suspend

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Stats. And Regs. ¶ 30,582 at 31,018 (1984).

the Transmission Owners' proposed return on equity ("ROE") for the maximum statutory period and set the matter for an evidentiary hearing.

Respectfully submitted,

___/s/ Harvey L Reiter________
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CERTIFICATE OF SERVICE

I hereby certify that I have this day served a copy of the foregoing document by first class mail upon each party on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, D.C., this 23rd day of December 2003.

/s/ Harvey L. Reiter______
Harvey L. Reiter