STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS
BEFORE THE PUBLIC UTILITIES COMMISSION

IN RE:	**THE NARRAGANSETT ELECTRIC**	:	
	COMPANY – INVESTIGATION	:	**DOCKET NO. 4065**
	AS TO THE PROPRIETY OF	:	
	PROPOSED TARIFF CHANGES	:	

POST-HEARING BRIEF OF THE DIVISION OF PUBLIC UTILITIES AND CARRIERS

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TABLE OF CONTENTS

I. INTRODUCTION[1]

On June 1, 2009, the Narragansett Electric Company, d/b/a National Grid (the "Company") filed a rate application with the Public Utilities Commission (the "Commission") seeking, among other relief, a base rate revenue increase of $63.586 million, or a 29.5% of rate year tariff revenues, an 11.6% return on equity, and an overall rate of return of 8.98%. Including the effect of shifting $9.752 million of uncollectible accounts from distribution rates to standard offer service, the Company's total requested increase is $73.338 million or 34% of rate year base distribution revenues.

In addition to its revenue requirements requests, the Company sought the following principal annual reconciliation mechanisms: (i) allowed revenues, *i.e.*, revenue decoupling, (ii) capital expenditures, (iii) inflation on operating expenses, (iv) inspection and maintenance ("I & M") expenditures, (v) commodity-related uncollectible expenses, (vi) delivery-related uncollectible expenses, and (vii) pension and OPEB costs.[2]

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[1] This Brief is intended to provide the Commission with a discussion of the governing legal framework to facilitate the Commission's resolution of the principal issues in the pending docket. The omission of any issue in this Brief may not be construed as a waiver of the Division's position, recommendation or contention with respect to the particular issue. All of the factual bases, recommendations and conclusions of the Division with respect to each of the issues contested and/or discussed by the Division in Docket No. 4065 are contained in the direct and surrebuttal testimonies of the Division's witnesses, as well as the testimony elicited from those witnesses at hearing—all of which are expressly restated and incorporated herein by reference.

[2] On June 5, 2009, the Commission held a pre-hearing conference, proposing to establish among other deadlines a September 1, 2009 filing date for the Division's direct testimony. On June 9, 2009, the Commission implemented a pre-hearing schedule establishing deadlines for the Division's and Intervenors' Direct Testimony of September 1, 2009. Hearings were to commence on October 19, 2009. With some minor modifications, the implemented schedule reflected that which had been proposed on June 5, 2009. On the same date, the Division filed a motion to amend the schedule, contending, among other issues, that the proposed schedule established by the Commission on June 5, 2009 did not afford the Division sufficient time to prepare for hearing and that the Company's filing was defective.

On June 29, 2009, the Commission held a Technical Session in which the Company presented an overview of its direct case. On June 30, 2009, the Commission decided the Division's motion to amend schedule and issued a revised procedural schedule. Pursuant to this new schedule, the Commission postponed the date for commencement of hearings from September 15, 2009 to November 2, 2009. The Commission also afforded the Division two additional weeks to submit direct testimony (to September 15, 2009), fourteen working days after the Company's rebuttal deadline to submit surrebuttal testimony, and at least thirty days to file a post-hearing brief. In Re: National Grid Application to Change Rate Schedules, Docket No. 4065, Order No. 19711 (July 16, 2009). All of the other relief contained in the Division's motion was denied.

Based on the Company's filing and extensive document production, the Division recommended in its direct and surrebuttal cases that the Commission give the Company a 47.50% equity capital structure, a return on equity of 10.1%, and an overall rate of return of 7.54%. Overall, the Division recommended that the Commission reduce the Company's base rate revenue requirement as filed by $37.872 million to $241.257 million or 11.93% greater than the revenues produced by base rates currently in effect. Among other adjustments, the Division recommended that the Commission: (i) reduce the Company's return on rate base and associated income taxes by $15.529 million, (ii) reduce the Company's operating and maintenance expenses by $18.653 million, and (iii) reduce the Company's delivery-related uncollectible accounts expense by $2.933 million.

The Division further recommended that the Commission deny the Company's requests to implement annual adjustment reconciliation mechanisms for allowed revenues, inflation on operating expenses, capital expenditures and I & M expense. The Division did not oppose the Company's implementation of commodity-related uncollectibles but recommended that the Commission adjust the Company's recovery of commodity-related uncollectibles expense in a manner similar to the Commission-approved treatment for the Company's gas operations in Docket No. 3943, Order No. 19563. The Division also recommended certain changes in the

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On August 12, 2009, the Division filed a motion for an expedited pre-hearing conference to revise the procedural schedule contending that the Company had repeatedly failed to comply with an agreed-to 14-day discovery deadline. Pursuant to a pre-hearing conference that transpired on August 18, 2009, the Commission maintained the June 30, 2009 procedural schedule intact subject to the production of all pending data request responses by August 21, 2009, among other conditions. On September 15, 2009 and October 27, 2009, the Division and Intervenors filed direct and surrebuttal testimony, respectively. The Division's direct and surrebuttal case consisted of testimony of seven expert consultants, each of whom provided testimony regarding various components of the Company's filing as well as discovery responses provided by the Company virtually from the commencement of the proceeding.

The Commission commenced hearings on November 2, 2009, which continued on November 3, 4, 5, 6, 12, 13, 23, 30, 2009, as well as on December 1 and 2, 2009. On December 1, 2009, the Company submitted a response to an alleged Commission Record Request No. 12 (the "Response") and, on the following day requested to call an unlisted and previously unidentified witness, Michael D. Laflamme. On December 7, 2009, the Division objected to and moved to strike the response, including seeking to bar Mr. Laflamme from testifying in Docket No. 4065. On December 8, 2009, the Commission granted the Division's motion in part striking the Response in its entirety with the exception of pages 49-53 and taking testimony from Mr. Laflamme regarding those pages on that date.

Company's cost-of-service study, which result in the Residential Class earning a return comparable to the average return. Finally, the Division recommended certain mitigating adjustments in the determination of class revenues that would serve the objective of gradualism, including accounting for the Company's proposed shift of approximately $4.0 million in transmission charges from the C & I Large Demand Class to the Residential Class.

The Division continues to advocate the position reflected in its direct and surrebuttal testimonies. Accordingly, the Division requests that the Commission deny and dismiss the Company's application, and award the Company rate recovery and such other relief as more particularly set forth in those testimonies and in this post-hearing brief.

II. ARGUMENT

A. BURDEN OF PROOF

G.L. § 39-3-12 provides in pertinent part as follows:

> in any hearing involving any proposed rate increase in any rate, toll or charge the burden of proof to show that the increase is necessary in order to obtain a reasonable compensation for the service rendered shall be upon the utility.

The Rhode Island Supreme Court has repeatedly held that this fundamental principle governs each aspect of the rate setting process before the Commission. Interstate Navigation Co. v. Burke, 465 A.2d 750, 758 (R.I. 1983). Thus, the Court has held that the utility must establish not only that it requires an overall increase by precise cost information, New England Tel & Tel v. Public Utilities Comm'n, 446 A.2d 1376, 1383 (R.I. 1982), but also that its proposed schedule of rates is nondiscriminatory. United States v. Public Utilities Comm'n, 393 A.2d 1092, 1094 (R.I. 1978). The Court has also observed that even if the Division does not offer any evidence in connection with a particular issue, the utility is required to prove by substantial evidence that it is entitled to prevail on that issue. Valley Gas Co. v. Burke, 406 A.2d 366, 369 (R.I. 1979).

Conflicting evidence will result in the utility's having failed to satisfy its burden of proof. Narragansett Electric Co. v. Harsch, 368 A.2d 1194, 1210 (R.I.1977); In Re: Application for Rate Change Pursuant to R.I.G.L. §§ 39-3-10 and 39-3-11 of Narragansett Electric, Docket No. 3943, Order No. 19563 at 29 (January 29, 2009). Incorrect assignment of the burden proof to the Division is an error of law. Public Utilities Comm'n, 393 A.2d at 964; Michaelson v. New England Tel. & Tel, 404 A.2d 799, 806 (R.I. 1979).

B. RATE OF RETURN

1. Cost Of Equity

a. DCF Analysis

Citing numerous precedents, this Commission has ruled that it "regularly relies upon the discounted cash flow ("DCF") methodology to determine the cost of equity capital." E.g., In Re: Tariff Filing Made by the Narragansett Electric Co., Docket No. 2019, Order No. 13899 at 8 (April 10, 1992); In Re: South County Gas Co. Rate Application, Docket No. 1671, Order No. 10950 at 15 (June 17, 1983) (where the Commission stated its preference for the DCF methodology). See In Re Tariff Filing Made by Valley Gas Co. and Bristol & Warren Gas Co., Docket No. 2276, Order No. 14834 (October 18, 1995) (in determining the cost of equity over the last several years, this Commission has consistently stated its preference for the use of the DCF methodology). Thus, the Commission must "focus" on DCF studies performed by the Division and/or the Company in arriving at its cost of equity determination. Narragansett Electric, Docket No. 2019, Order No. 13899 at 8.

Analysis of the Company's DCF study in the pending matter reveals a significant defect: namely, the proxy group[3] entities selected by the Company "do not adequately reflect the risk profile of the [Company] with or without a [revenue decoupling mechanism]." Kahal Direct at 51. Candidates for the Company's proxy group could qualify for inclusion in the proxy group if up to 40% of their identifiable assets were devoted to non-utility operations.[4] Moul Direct at 6. Three of the companies contained in the proxy group, Sempra, Southern California Edison (an Edison International subsidiary) and PG & E, in fact, own substantial nuclear generation plants. 11/12/2009 Tr. at 228; Resp. to Division Data Request 4-22. Through Southern California Edison, Edison International owns extensive unregulated coal-fired generating and merchant power assets; Sempra owns substantial unregulated LNG operations. 11/12/2009 Tr. at 22; Resp. to Division Data Request 4-22. Pepco, through its subsidiary, Conectiv, owns extensive merchant power assets. 11/12/2009 Tr. at 23; Resp. to Division Data Request 4-22. Portland General Electric is in the process of decommissioning a nuclear facility and owns significant coal-fired and wind generation. 11/12/2009 Tr. at 22; Resp. to Division Data Request 4-22. Idacorp, Inc. owns significant hydroelectric generation and three coal-fired plants as well. 11/12/2009 Tr. at 23; Resp. to Division Data Request 4-22. With the exception of Consolidated Edison, each member of the Company's proxy group is vertically integrated and/or has extensive merchant plant operations.[5] Hence, the Company's DCF approach compels the Company's

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[3] The Commission has approved use of a market proxy when the utility, like the Company, is not publicly traded, in order to apply the DCF model. Tariff Filings Made by Providence Gas Co., Docket No. 2082, Order 14311 at 12-13 (January 15, 1993).

[4] A standard flatly rejected by the New Hampshire Public Utilities Commission, "because 100% of the Company's assets are subject to regulation, [an] 85% cut-off is more likely to reflect the risks faced by the Company than a 60% cut-off would." In Re EnergyNorth Natural Gas, Inc. d/b/a National Grid NH, DG 08-009, Order No. 24,972 at 59 (May 29, 2009).

[5] Mr. Kahal testified (and Mr. Moul does not dispute) that vertically integrated electrics are in a separate risk group and are "somewhat riskier" than the Company. S & P views unregulated merchant generation and marketing as "the absolute worst proxy" for the Company. Kahal Direct at 39.

customers to pay the common equity costs of risky generation assets as part of their distribution rates.

By contrast, the Division's expert consultant, Matthew I. Kahal, employed two proxy groups, one consisting of local gas distribution companies and the other consisting of electric distribution companies, to develop his DCF recommendation. Critical to the development of the former group in his analysis, Mr. Kahal observed that in 2004 Standard & Poors developed and implemented a new system for ranking business risks (least to most risk) of utility and power companies: 1) transmission and distribution – gas, water and electric, 2) transmission only – electric, gas and other, 3) integrated electric, gas and combination utilities, 4) diversified energy and diversified non-energy, and 5) energy merchant/power, developer/trader, marketing. Kahal Direct at 38. The Company is included in Category in 1) with gas distribution companies for business risk purposes. Id. at 39. "What this demonstrates . . . is that gas distribution companies," such as those identified by Mr. Kahal in his Direct Testimony at MIK-3 at 1, "are superior to vertically-integrated electrics as a proxy for [the Company]." Id. at 39. Mr. Kahal's conclusion in this regard is corroborated by the fact that Value Line's Safety and Financial Strength ratings, beta and 2008 common equity ratio on average all show that the Division's gas proxy companies are reasonably comparable in risk to the Company as measured by these criteria. Id. at 32. By contrast, the same indicia generally reflect higher risk for the Company's proxy group members. In sum, the consequence of the Company's selection of entities for its proxy group with greater business risk than the Company (which the Company concedes) is a DCF recommendation that reflects a materially elevated cost of equity result. 11/23/2009 Tr. at 23.[6 & 7]

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[6] For the gas utility proxy group, Mr. Kahal calculated the adjusted dividend yield for the six months ending August 2009 at 4.7%. Kahal Direct. at 33, 37. Then using four well-known sources of projected earnings, Mr. Kahal identified a reasonable range of long-term earnings growth of 5.0-5.5%. Id., MIK-4 at 3, 4. Adding dividend yield

b. The Company's Risk Premium Analysis

This Commission "has regularly rejected the risk premium or 'interest premium approach' as a viable means of calculating the cost of equity capital." Narragansett Electric, Docket No. 2019, Order No. 13888 at 8. See also Providence Gas, Docket No. 2082, Order 14311 at 13; In Re: Providence Gas Co. Tariff Filing, Docket No. 1612, Order No. 10711 at 15 (June 23, 1982). As a matter of regulatory precedent alone, the Commission must reject the Company's Risk Premium methodology in arriving at a cost of equity determination.

Even if the Commission were to consider the Risk Premium methodology in arriving at a cost of equity determination, the Company's application of the methodology contains a significant defect: Mr. Moul's historic return study simply does not reflect "the large stock market losses that occurred in 2008." Kahal Direct at 60. Nowhere in the entire Record does the Company contend otherwise. When 2008 data are incorporated into the long-term historic average, the arithmetic risk premium is reduced to 5.02 percent and the geometric risk premium is reduced to 2.46%. Id. at 61. The updated Risk Premium analysis produces a cost of equity range of "8.2 to 10.4 percent," a result that is entirely consistent with the Division's cost of equity recommendation. Id. The Company's Risk Premium methodology is facially defective and should be rejected by the Commission.

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to cost of equity produced a cost of equity range of 9.7-10.2%. Mr. Kahal's cost of equity recommendation is 10.1%. Id., MIK-4 at 1. Application of the six-month average yield and "spot yields" does not alter the Division's DCF cost of equity recommendation. Division Resp. to Commission First Data Request at 1-2.

[7] Mr. Kahal's electric utility DCF analysis supports his gas utility DCF recommendation. Identifying seven reasonably homogenous utilities primarily engaged in electric distribution service and operating in the Northeast, Kahal Direct, MIK-3 at 2, Mr. Kahal calculated a going forward yield of 5.9% and, again, using four well-known sources of data derived a long-term growth range of 3.8% to 4.8%. Id., MIK-5 at 3, 4. The sum of these figures produces a DCF cost of equity range of 9.7% to 10.7%. Again, application of the six-month average yield and "spot yields" does not alter the Division's DCF cost of equity recommendation. Division Resp. to Commission First Data Request at 3-4.

c. The Company's Capital Asset Pricing Model ("CAPM")

This Commission also has "consistently rejected . . . the CAPM approach as a viable alternative method of estimating cost of equity capital." E.g., Valley Gas, Docket No. 2276, Order No. 14834 at 10 (October 18, 1995). See also In re: Tariff Filing Made by Valley Gas Co., Docket No. 2038, Order No. 14048 at 10 (January 3, 1992). Thus, the Commission should not accord any weight to the Company's incorporation of a CAPM into its cost of equity recommendation.

Nonetheless, if the Commission were to apply a CAPM to arrive at a cost of equity determination, the Company's analysis is severely flawed. First, the Company has not presented any "evidence," other than speculative generalizations, see Moul Direct at 55, that size is a significant factor in determining a company's cost of equity. Kahal Surrebuttal at 14. By its size adjustment (.94), the Company views itself as a distinct and separate entity from National Grid. However, it is undisputed that the Company is "financially fully integrated with National Grid," id. at 15, and the Commission has consistently treated the Company as so integrated, taking into consideration the "cost savings scale economies" resulting from integration of the two entities in setting rates. Id. The Company's proposed size adjustment, then, "is at odds with standard and sound ratemaking, and should be rejected." Id. Other commissions are in accord. See e.g., EnergyNorth, DG 08-009, Order No. 24,972 at 69 (rejecting leverage and flotation adjustments proposed by the Company in its CAPM).

Just as significantly, the Record conclusively reflects that one of the Company's risk premium measures based on Value Line and S& P 500 projected returns data fell from 11.54% in March 2009 to 8.41% in September, 2009. Kahal Surrebuttal at 14. The Company, however, failed to revise its CAPM to account for these updated, sharply lower risk premium estimates. Had the Company done so (and no reason was given for not doing so), the Company's CAPM would have reflected a cost of equity of 9.33%, a result which supports a cost of equity of less than 10%. Id. The Company's CAPM is flawed and should be rejected by the Commission.

2. Cost Of Long-Term Debt[8]

The Company proposes a 6.79% cost of long-term debt. However, the Company developed its cost rate in April of 2009 when interest rates were unusually elevated due to the nationwide credit crisis, which commenced in the fall of 2008 and continued well into the spring of the following year. Kahal Direct at 20. This Commission has held that the appropriate measure of the cost of long-term debt is that which is most current and will most likely reflect the cost that will be carried into the rate year. In Re: Tariff Filing Made by the Providence Gas Co., Docket No. 2286, Order No. 14859 at 7 (November 17, 1995).

Since the time of the Company's proposal, interest rates and credit spreads for single A utilities, such as the Company, have declined. Id. The "August 2009 yield on single-A long-term (*i.e.*, 20 to 30-year) utility bonds was 5.7%." The August, 2009 yield on long-term Treasury bonds was 4.3%. Kahal Surrebuttal at 3 & MIK-2. For September, 2009 "10-year Treasury yields averaged 3.4 percent, with 30-year Treasury bonds yielding 4.2%. The average of 10-year and 30-year Treasury yields as of mid-October are quite close to these September average figures at 3.8%, which "[i]ncluding a credit spread of 170 basis points . . . plus 10 basis points for issuance expenses, produces an updated cost of long-term debt estimate of 5.6%." Id.

Nowhere in the Direct or Rebuttal Testimony of Mr. Moul (or anywhere else in the Record) does the Company contest this "current" data or the calculation of the Division. In fact, at hearing, Mr. Moul conceded that his 6.79% figure was a mere placeholder and the current cost

[8] The Company has conceded that the Division's conclusion of 1.6% for short term debt is "the Company's current projection of the average short term debt interest rate for the rate year." Company Response to Division Data Request No. 31-13. No dispute exists that 1.6% is the appropriate cost rate for the Company's short-term debt, 11/12/2009 Tr. at 9, or that the Company's capital structure ratio for short-term debt is 4.98%. Compare Moul Direct, NG-PRM-1 with Kahal Surrebuttal, MIK-1 (October 2009 Update).

rate for long-term debt was less than 6.0%. 11/12/2009 Tr. at 17-18. The Commission, therefore, should find that 5.6% is the appropriate cost of long-term debt.[9]

3. Capital Structure[10]

This Commission has held that it will "use a utility's actual capital structure in setting rates, unless that capital structure is not reasonable for rate-setting purposes." Narragansett Electric, Docket No. 3943, Order No. 19563 at 16. In all events, the Company possesses the burden of proving that its capital structure is reasonable for rate-setting purposes. Interstate Navigation v. Burke, 465 A.2d 750, 755 (R.I. 1983); G.L. § 39-3-12 (providing that "[a]t any hearing involving any proposed rate increase in any rate, toll, or charge, the burden of proof to show that the increase is . . . reasonable . . . shall be upon the utility").

The Company executed a settlement agreement ("the Settlement") with the Division's Advocacy Section in Docket No. D-2009-09-49. On December 9, 2009, the Division approved the Settlement in Order No. 19847 (the "Order"). Among other terms, under the Settlement, the Company is authorized to make an initial issuance of new long-term debt in an amount not to exceed an aggregate principal amount of $550 million. The Settlement also authorizes the Company to seek permission to "do additional debt issuances in an amount not to exceed an aggregate principal amount of $290 million . . . without the need for a new application or additional notice" provided the Company notifies the Division on or before March 31, 2011 of its intent to seek such permission and of the approximate date of the issuance. The Settlement and

[9] The Company's capital structure ratio for long-term debt is 47.33% (100% minus the agreed-to figures for the Company's preferred stock (.19%) and short-term debt (4.98%) and the Division's calculated figure for common equity (47.5%) infra).

[10] The Company and the Division agree that the Company's preferred stock will consist of .19% of total capital at a cost rate of 4.50%. Compare Moul Direct, NG-PRM-1 at 1 and Kahal Surrebuttal, MIK-1 at 1 (October 2009 Update)

Order do not constitute Division concurrence with "the capital structure proposed by the Company in Docket No. 4065 or in any future docket."

The Company contends that its planned restructuring—the issuance of $550 million in new long-term debt—will reduce the Company's common equity ratio from 77.99% to approximately 50%, which will then reflect the actual capital structure of the utility in setting rates. The restructuring plan, however, is merely a statement of the Company's intentions or anticipation. 11/12/2009 Tr. at 166. The transactions that will actually effect the recapitalization will occur at some unknown date in the future, and it is far from clear what capital structure this recapitalization process will actually produce in the near term. Accordingly, the Company retains the burden of proving that its proposed capital structure is reasonable. The Company has failed to meet this burden. Interstate Navigation, 465 A.2d at 755.

Mr. Kahal calculated common equity ratios for both of the Division's gas and electric proxy groups, inclusive of short-term debt and long-term debt maturing within one year at 47.4% and 44.8%, respectively. Kahal Direct at 18. The reported, year-to-date equity as a percentage of capital structure for electric and gas utilities corroborate Mr. Kahal's calculations. See Resp. to Div. Data Request 31-10 at 3. The August 28, 2009 Value Line, moreover, identifies an industry average equity ratio for 2008 of 45.3% and forecasted ratio of 47% for 2009. These percentages are calculated excluding both short-term and long-term debt maturing within one year. Had both forms of debt been included in Value Line's calculation, the industry average equity ratio would have been below those reported. Division Exhibit 25. All of the Record evidence, then, supports the use of 47.5% common equity ratio recommended by the Division as reasonable and appropriate for ratemaking in this case.

4. Overall Rate Of Return

The Company's overall rate of return is the sum of the Company's weighted cost of each capital type. E.g., Valley Gas Co., Docket No. 2276, Order No. 14834 at 5-6. Based on its recommendations for the cost of and capital structure percentages of each form of capital, the Division calculates the Company's overall rate of return at 7.54%. See Kahal Surrebuttal, MIK-1 at 1 (October 2009 Update).

C. REVENUE REQUIREMENTS

1. Rate Base

a. Electric Plant In Service

The Rhode Island Supreme Court has held that a utility's rate base represents the total investments in or the fair value of the used and useful property, which it necessarily devotes to rendering of the regulated service. Rhode Island Consumers' Council v. Smith, 302 A.2d 757, 767 (R.I. 1973). The largest item in a utility's rate base is its investment in plant. Id. This Commission has required utilities to show that the Company's capital projects will be used and useful by the end of the rate year. Providence Gas Co., Docket No. 2286, Order No. 14859 at 21. An expectation that the projects will be placed into service by that time is not sufficient. Id. See also South County Gas Co., Docket No. 1671, Order 10950 at 20-21 (as there was no evidence when the capital project would be undertaken or its specific cost, the projection of plant growth would be nothing more than speculation). Indeed, when the Company's actual construction activity is below the Company's levels budgeted in the rate year, the Commission has adopted the recommendations of the Division based on actual construction levels. In Re Tariff Filing by Narragansett Electric Co., Docket No. 1659, Order No. 10901 at 20 (March 30, 1983).

In the pending matter, the Company budgeted monthly gross plant additions between January and March, 2009 of $4.5 million and $5.4 million between April and July, 2009. The Company's actual gross additions between January and July, 2009, however, averaged only about $4 million per month. Effron Surrebuttal at 12; Resp. to Division Data Request 23-5. Resp. to Division Data Request 27-2 (showing shortfall in actual plant additions as continuing through September 30, 2009). Mr. Pettigrew confirmed this consistent practice of capital under-spending, conceding that the Company's has been below budget in every month in CY 2009. 11/3/2009 Tr. at 30.

This concession follows a familiar pattern. In Docket No. 3943, the Division proposed a similar reduction to capital expenses based on the fact that current actual expenses were not keeping up with projected expenses. 9/9/2009 Tr. at 9 (Docket No. 3943). The Company's witness again conceded, "...our current run rate of capital spending was a little below the projections." The witness proceeded to concede that actual spending in the second half of FY 2008 was roughly $3.5 million below budgeted spending for the same period and, obviously, did not make up for the lower rate of spending in the first six months of the year. Id. at 11-12.

In this case, as in Docket No. 3943, the Company's actual capital spending has been consistently below its budgeted spending. The Commission, therefore, should adopt the Division's recommendation and use the actual plant addition rates, which result in the calculation of the average rate year balance of plant in service for the rate year of $1,212,525,000 or $19.953 million less than the Company's forecast. Effron Direct at 29; Effron Surrebuttal at 12 & DJE-8S & 8.1S.

b. Cash Working Capital ("CWC")

"An allowance in rate base for working capital is not something to which a utility is entitled as a matter of right." Harsch, 368 A.2d at 1203; Rhode Island Consumers' Council v.

Smith, 322 A.2d 17, 26 (R.I. 1974). This Commission also has held that it is "essential" for the Company to ensure "consistent use of [the] reference period in the measurement of expense and revenue leads and lags." Narragansett Electric Co., Docket No. 1659, Order No. 10901 at 17.

Mr. Effron explained that in Docket No. 3943 the Company calculated that taxes were "recovered in rates approximately 32 days before cash is disbursed in payment of the expense." Effron Direct at 32. In the present matter, the Company calculates this lag period at 123 days. Id. According to Mr. Effron, "the main reason for the discrepancy is that the lag in Docket No. 3943 is based on the lag payment of the municipal tax expense accrued in the test year," Effron Surrebuttal at 15, while the lag in the present case "is based on the municipal tax payments in relation to the fiscal year of the taxing authorities." Id. The lag period in the pending docket is not "consistent" with that which the Commission accepted in Docket No. 3943, and it is not "consistent" with the accounting method—the accrual method—upon which the Company's expenses are determined for book and ratemaking purposes. Effron Surrebuttal at 15. The Commission should adopt the Division's recommended reduction of $9.893 million to the CWC related to municipal taxes. See Providence Gas, Docket No. 2286, Order No. 14859 at 26 (the Commission required consistent treatment of the lag period with that used in the prior docket).

c. Return On Rate Base

Using the overall rate of return of 7.54% recommended by the Mr. Kahal above, the Division calculates a return on rate base of $44.001 million. Effron Surrebuttal, Schedule DJE-8S. See Narragansett Electric Co., Docket No. 1659, Order No. 10901 at 22 (showing calculation of the return on rate base).

2. Operating And Maintenance Expense

a. Incentive Compensation

This Commission has held that "ratepayers are responsible for that portion of executive incentive compensation that directly benefits them" and that "shareholders should be responsible for that portion that benefits them." Providence Gas, Docket No. 2286, Order No. 14859 at 35. The Commission's ruling follows both Rhode Island and national judicial precedent, which has addressed the issue.

In Providence Gas Co. v. Malachowski, 656 A.2d 949, 952 (R.I. 1995), the Commission had disallowed expenses associated with a Supplemental Executive Retirement Plan ("SERP") of the Providence Gas Company ("Providence Gas"). Providence Gas appealed asserting that the SERP is "a form of management compensation . . . which cannot be disallowed 'simply because it benefits shareholders.'" Providence Gas, 656 A.2d at 951.

The Rhode Island Supreme Court disagreed, reasoning:

> The [Commission] rejected the Company's attempt to reward executive talent for employment not dedicated to the company's ratepayers. The [Commission's] statement was clear: the SERP expense does not benefit ratepayers. The [Commission] rejected the SERP expense and called it an unreasonable and excessive expense that does not directly benefit ratepayers.

Id. at 952. Accordingly, the Court found that the Commission's "decision regarding SERP expenses was just, reasonable, lawful, and supported by legal evidence." Id.

In U.S. Communications, Inc. v. Public Service Comm'n of Utah, 901 P.2d 270, 276 (Utah 1995), the Utah Division of Public Utilities and Carriers ("Utah Division") proposed disallowance of the incentive compensation plan expense for executives of U.S. West Communications Services, Inc. ("USWC"). Id. The plan consisted of stock options and job performance shares, both of which provided additional compensation to the executives if U.S. West, Inc.'s stock price increased in the long run. Id.

The Utah Division contended "these costs were unreasonable in that they were tied exclusively to shareholder return and therefore provided no benefit to ratepayers." Id. By contrast, USWC argued that many events, which result in increased stock prices, are beneficial to ratepayers. Id.

The Utah Public Service Commission ("Utah Commission") adopted the Utah Division's recommendation finding:

> The [p]lan rewards executives on the basis of financial performance using criteria which benefit shareholders rather than ratepayers. The [p]lan focuses upon shareholder total returns. The awards are not based upon individual or team performance, productivity, customer service or cost control.

Id.

On appeal the Utah Supreme Court sustained the Utah Commission's ruling reasoning that rates are "just and reasonable" only if consumer interests are protected and if the financial health of the utility remains strong. Id. (citing Federal Power Comm'n v. Memphis Light, Gas & Water Div., 411 U.S. 458, 474 (1973)). The Utah Commission, therefore, appropriately "made the disallowance because it found that the long-term incentive compensation plan was designed to increase shareholder wealth only and provided no real benefit to ratepayers." Id. at 277. Virtually every judicial precedent addressing the issue is in accord. See e.g., Entergy Arkansas, Inc. v. Arkansas Public Service Comm'n, 289 S.W.3d 513, 525 (Ark. Ct. App. 2008) (affirming the commission's decision to split the cost of employee incentive compensation between ratepayers and shareholders on the ground that the "predominantly financial incentives" did not have a direct ratepayer benefit).

In the pending matter, the Company's witness, William F. Dowd, testified that the Company's employee compensation plans are designed to encourage good employee performance, with 40% to 50% of the incentive pay being linked to individual objectives that are directly tied to established service quality measures such as safety, reliability and customer satisfaction. Mr. Dowd then observed that *"[t]he remaining portion of the incentive pay is tied to company financial performance ... "* Dowd Direct at 8-9 (emphasis added). This performance is tied exclusively to achieving "financial objectives"—objectives specifically defined by Mr. Dowd as "earnings per share, net operating profit and cash flow." Dowd Direct at 7.

Based on Mr. Dowd's testimony and judicial and regulatory precedent, the Division's expert consultant, David J. Effron, testified that at least 50% of the Company's incentive compensation is based on the attainment of financial goals, such as earnings or return on equity, which should not be recoverable from ratepayers. Effron Direct at 5-6. Mr. Effron explained:

> The attainment of financial targets, such as earnings or rate of return is a shareholder-oriented goal, not a customer-oriented goals . . . if all else is equal higher rates will result in higher revenues, which in turn will result in higher earnings. Thus, including incentive compensation related to the achievement of earnings targets in the revenue requirement would, in effect, require customers to reward company management on a contingency basis for getting them to pay higher rates. If the incentive compensation program is successful in increasing earnings, the shareholders should be willing to reward management accordingly and absorb the cost of the program. As shareholders are the primary beneficiaries of increases to earnings, it should be those shareholders, not customers, who bear the cost of the incentive compensation related to earnings.

Effron Direct at 6. The Division's downward adjustment of $1.204 million to reflect the 50% of the Company's plan related to the achievement of financial objectives, therefore, is legally correct and supported by the entirety of the evidence on the Record. E.g., Providence Gas, 656 A.2d at 951.

b. Contracted Hiring Requirement

This Commission has ruled that when a utility requests additional compensation related to the hiring of additional employees, the utility must provide "extensive detail" regarding the expense associated with those employees. Providence Gas, Docket No. 2286, Order No. 14859 at 33. See In Re: Narragansett Bay Comm'n Abbreviated Application for Rate Relief, Docket

No. 3592, Order No. 18124 at 10-11 (January 21, 2005) (when a utility has provided little or no evidence that it is being pro-active in limiting personnel expenses, the Commission properly limited funding of labor expense to the level that was previously approved).

In the pending matter, the Company proposes to increase pro forma test year operation and maintenance expense by $1.363 million to reflect additional expenses associated with hiring requirements through the 2010 rate year. The Company, however, has not provided the Commission with any level of detail regarding these claimed incremental expenses, including failing to identify "any additional tasks that the new hires will be performing." Effron Direct at 7.

Moreover, the minimum staffing requirements contained in the Company's union contract enable the Company to "reduce its reliance on outside contractors." As Mr. Dowd testified at hearing, the contract provides that by May 11, 2010, it is required to "cease the use of platform contractors." 11/5/2009 Tr. at 97. The contract, however, proceeds to require the Company and the union "to work jointly to identify an appropriate percentage of work to be performed by *contractors,*" Resp. to Div. Data Request 1-20 at 3 (emphasis added), and "reserves to the Company all of its rights relative to the assignment of work of the work plan between employees and *contractors*." Id. (emphasis added). The contract does not, as intimated by Mr. Dowd at hearing, solely require the elimination of "a small subset of the contracting world" (*i.e.,* platform contractors), but enables the Company to replace a portion of the $10 million in 2008 outside contractor expense with in-house labor. Effron Direct at 7.

The Massachusetts Department of Public Utilities ("DPU") recently rejected a similar Company proposal to increase pro forma test year operation and maintenance expense to reflect additional expenses associated with hiring requirements through the 2010 rate year, completely validating Mr. Effron's analysis regarding the proposed adjustment. Reasoning that although the number of employees will increase in the post-test year period under the terms of the union contracts, the DPU observed that "the evidence demonstrates that the additional workers will displace outside contractors, and, therefore, there will be an offset cost savings not accounted by National Grid." In Re: Petition of Massachusetts Electric Co. and Nantucket Electric Co. Pursuant to G. L. c. 164 § 94, and 220 C.M.R. 5.00 et seq. for a General Increase in Electric Rates and Approval of a Revenue Decoupling Mechanism, D.P.U. 09-39 at 136-37 (November 30, 2009). The Commission, therefore, should eliminate the Company's proposed pro forma adjustment to increase test year operation and maintenance expense by $1.363 million.

c. Customer Assistance Advocacy

Public utility commissions and courts, alike, unanimously hold that a legitimate operational expense for an electric utility should have a direct ratepayer benefit before being included in utility rates. Providence Gas, 656 A.2d at 952; Rhode Island Consumers' Council, 322 A.2d at 25; Entergy Arkansas, 289 S.W.2d at 525. Thus, a utility's expense request that largely duplicates services provided to the public by state or local agencies does not provide ratepayers with the requisite direct benefit so as to justify recovery from ratepayers.

Rhode Island CAP agencies consist of eight separate non-profit companies, which employ more than 1,000 people to serve Rhode Island. Among their many functions, CAP agencies provide information regarding, and/or directly administer programs for which low-income individuals may qualify, including but not limited to Low Income Home Energy Assistance Program, Weatherization Assistance Program and the Appliance Management Program.

When asked by Commission counsel what the two proposed consumer advocate positions will do "in addition to what Rhode Island ratepayers already receiving services from the CAP agencies" and the Office of Energy Resources ("OER"), the Company's witness, Rudolf L.

Wynter, Jr., testified that they "have knowledge of energy efficiency" and "understand the various programs" that low-income individuals "can apply for to get themselves aid..." 11/6/2009 Tr. at 89. When Commission counsel pressed Mr. Wynter as to whether the CAP agencies and OER already possessed that knowledge, Mr. Wynter conceded: "I'm sure they do have that knowledge." 11/6/2009 Tr. at 89.

The two proposed consumer advocate positions are entirely duplicative of services provided to the public by Rhode Island CAP agencies and the OER, and accordingly, do not provide ratepayers with any direct benefit whatsoever. The Commission should reduce the Company's pro forma test year operation and maintenance expense by $182,000 to reflect the elimination of funding for these positions.

d. Rate Case Expense

Many commissions that have addressed this issue have found five years as the appropriate period over which to allow a utility to recover rate case expense charged to ratepayers. E.g., Kansas Ind. Consumers Group, Inc. v. State Corp. Comm'n of the State of Kansas, 138 P.2d 357-58 (Kan. 2006). See BP West Coast Products, LLC v. FERC, 374 F.2d 1263, 1293 (D.C. Cir. 2004) (where commission allowed utility to recover its litigation costs over five-year period). This Commission, as well as other commissions, have used a five-year period to give utilities recovery of items such as wholesale sales, In Re: Pawtucket Water Supply Bd. General Rate Filing, Docket No. 3497, Order No. 17574 at 47 (May 21, 2003), and balances associated with deferred income taxes. Chesapeake Utilities Corp. v. Delaware Public Service Comm'n, 705 A.2d 1059, 1064 (Del. 1997). In fact, based on the Company's history of electric rate filing cases, the DPU recently found that a normalization period of six years was appropriate. Massachusetts Electric, D.P.U. 09-39 at 297.

The Company made rate filings in 1999 and 2004 both of which the Company settled in 2000 and 2004, respectively. Based, in part, on the time interval between these cases, Mr. Effron opined that "a normalization period of at least five years would be more appropriate" than the two-year period proposed by the Company. Effron Direct at 9.

For its part, the Company chose a "two-year recovery period." The Company "believ[ed]" that "inflationary and economic cost pressures on operating expenses" would make more frequent cases likely. O'Brien Direct at 29. The Record reflects that inflation, at present, is benign, and the Company's "belief" that rate cases might become more frequent, is purely speculative. The Division's downward adjustment of $519,000 is supported by the intervals between the Company's recent rate filings and an accepted amortization period that is directly related to those intervals. The Commission, therefore, should adopt the Division's recommendation to reduce the Company's requested rate year rate case expense by $519,000.

e. Customer Contact Activities

The Company requests additional funding in the amount of $376,000 for the "incremental cost associated with a substantially increased level of outbound calls as well as the increased level of inbound calls that the higher level of collections activity generates." Wynter Direct at 22. The Division observed that additional collection efforts should lead to decreased write-offs. Effron Direct at 10. Thus, reasonable and necessary incremental costs will "pay for themselves," thereby making it unnecessary to increase test year operation and maintenance expenses for collection efforts associated with these costs. Id.

The Division's recommendation incorporates the fundamental ratemaking principle that the Commission may approve only rates "reasonable and necessary to achieve compensation for services rendered." New England Tel. & Tel. Co. v. Public Utilities Comm'n, 446 A.2d 1376, 1383 (R.I. 1982); Bristol & Warren Gas Co. v. Harsch, 384 A.2d 298, 300 n. 4 (R.I. 1978).

Incremental costs that do not "pay for themselves" through decreased write-offs are not "necessary" to the Company's operations, and therefore, prohibited pursuant to these legal precedents. The Commission should deny the Company's request for additional funding of $376,000 to increase its collection efforts in order to control write-offs of accounts receivable and uncollectibles expense.

f. Economic Development Program

The Company requests $1.0 million in order to fund three components of its proposed Pilot Economic Development Program (the "Program"). According to the Company, the annual funding for the program will be allocated as follows: Targeted Infrastructure Improvement, $400,000; Urban Revitalization, $400,000; and Strategic Business Development, $200,000. Fields Direct at 11-13.

This Commission has held that "[c]ost of service represents the total of the operating expenses and return which the Company is allowed to recover through its approved rates. These costs must be representative of ongoing expenses necessarily incurred in providing service to the Company's ratepayers," Providence Gas, Docket No. 2286, Order 14859 at 30, and must be necessary to the provision of such service. New England Tel. & Tel. Co., 446 A.2d at 1383; Bristol & Warren Gas Co., 384 A.2d at 300 n. 4.

The Company's witness, Ms. Carmen Fields, testified that "the overarching principle" of the Program is to "help create jobs, attract new business and assist in retaining and helping businesses expand." Fields Direct at 6. To those ends, Ms. Fields testified that each of the Program's components is aimed at fostering "technology transfer and commercialization efforts in the renewable energy and life sciences," providing "support for 'green' business recruitment initiatives," Id. at 13, and focusing on the "development and marketing" of shovel ready sites. Id. at 5.

On its face, the Program is "not necessary for the provision of *distribution service*," Effron Direct at 11. On this ground alone, the Commission should disallow expenses related to the Program in their entirety. See Providence Gas Co, 656 A.2d at 952 (disallowance of program expense that did not directly benefit ratepayers was proper) Providence Gas, Docket No. 2286, Order 14589 at 30 (expenses must be necessarily incurred in providing service to the Company's ratepayers).

Each of the Program's components, however, also duplicates the principal mission and functions of the Rhode Island Economic Development Corporation ("RIDEC"). Like the Program, RIDEC's stated mission, is to "create jobs, help companies expand and develop their workforce, and identify opportunities to bring new companies into . . . the state." Division Exhibit 26 at 2; 11/13/2009 Tr. at 115. Like the Program, a principal focus of RIDEC is to attract "green businesses" and build a "green workforce" in Rhode Island. Division Exhibit 26 at 9. Lastly, RIDEC seeks to "encourage technology transfer," Division Exhibit 26 at 6, "evaluate sites as to their readiness and best use," and then incorporates those sites into "statewide marketing and attraction efforts." Division Exhibit 26 at 7. So does the Program. See Fields Direct, supra 5, 6 and 13; 11/13/2009 Tr. at 116,

Since RIDEC already provides all of the services to consumers that the Company proposes to provide to the public through the Program, the Program is unnecessary and a waste of ratepayer money. See e.g., New England Tel. & Tel. Co., 446 A.2d at 1383-84 (increase sought must be necessary to achieve reasonable compensation for the utility services rendered); Bristol & Warren Gas Co., 384 A.2d at 300 n. 4 (the same). See also G.L. § 39-3-12 (utility must show proposed rate increases are "necessary" for utility to receive reasonable compensation for services rendered). Based on the Record evidence, the Commission is required to disallow the Company's $1.0 million funding request for the Program.

g. *Vegetation Management*

The Rhode Island Supreme Court has held the Commission may approve only rates "reasonable and necessary to achieve compensation for services rendered." New England Tel. & Tel. Co, 446 A.2d at 1383; Bristol & Warren Gas Co., 384 A.2d at 300 n. 4. In the pending matter, the substantial evidence reflects that the additional funding the Company requests for its vegetation management program is not "necessary" for the Company to deliver reliable distribution service to its customers.

The Company requests $9.1 million of vegetation-management costs in the rate year. Pettigrew Direct at 30. This sum represents a $2 million or a 28% increase in the Company's annual expenditures for vegetation management in the rate year over the amount expended in the test year. Pettigrew Direct at 30. The Company's witness on the issue, John Pettigrew, testified that the principal reason for the increase was the conversion of "all pruning to circuit-base pruning," on a four-year, rather than a five-year cycle. Pettigrew Direct at 31.

The Company, however, concedes, "circuit pruning is not a new program," Pettigrew Direct at 31, and does not show how the additional costs of its "enhanced" program are necessary when the current level of test year spending is producing exceptional results in terms of system reliability. Hahn Direct at 8. The Record incontrovertibly establishes that the vegetation management program at test year funding levels has delivered for the Company: (i) "better than the average" System Average Interruption Duration Index ("SAIDI") performance since 2001, Pettigrew Direct at 6, (ii) comparable System Average Interruption Frequency Index ("SAIFI") to the average SAIFI experience since 2001, id., and (iii) comparable to the 1st quartile performance of other companies who participated in the IEEE Benchmarking Study for 2007. Division Exhibit 18 at 1.

Mr. Pettigrew's claim—that the changes the Company has undertaken with its vegetation management program have "contributed significantly its SAIDI and SAIFI performance," 11/3/2009 Tr. at 50—is wholly unsupported by the Record. Mr. Pettigrew repeatedly testified that: "the 2010 rate year amount reflects the strategies and policies that we have in place for vegetation management and reflect the costs that we saw when we did the procurement exercise last year to deliver those policies and strategies." 11/3/2009 Tr. at 119-120. See also 11/3/2009 Tr. at 94 (where Mr. Pettigrew acknowledged that vegetation management costs have increased reflecting the revisions that the Company made to the policy specifications and the procurement exercise of 2008). Yet, the Company achieved and maintained its "top-peforming" SAIDI and SAIFI reliability results as far back as 2006, two years prior to the Company's claimed modification of its vegetation maintenance program. See Pettigrew Direct at 6. As Mr. Hahn explained at hearing:

> It is my testimony that the company has been spending money on this [the vegetation management program]. A large increase of the type they have proposed does not appear to have been justified. And to include as a test-year adjustment without that justification would not be appropriate.

11/23/2009 Tr. at 55.

The Company has failed to show that the incremental funding request over its test year level for its vegetation management program is necessary to the provision of reliable electric distribution service. The Commission should reduce the Company's pro forma test year operations and maintenance expense by $1.985 million to reflect the elimination of this increase.

h. I & M Program Expense

This Commission has held that in order for a utility to receive rate recovery for a claimed expense, a utility must prove that the expense is both reasonable and *necessary* to the service rendered. New England Tel. & Tel. Co., 446 A.2d at 1383; Bristol & Warren Gas Co., 384 A.2d at 300; Providence Gas, Docket No. 2286, Order 14859 at 30; G.L. § 39-5-12. The Company requests incremental funding for the I & M Program of $2.094 million, along with a reconciliation mechanism to recover such costs. Pettigrew Direct, NG-JP-1. The Company's request does not remotely satisfy this legal standard.

The Company concedes that the I & M strategy merely represents an "enhancement" of traditional Company practices. The resulting "work activities" that will be performed under the I & M program "are the same activities performed in the past…," Pettigrew Direct at 14, such as inspections on equipment components, such as overhead poles, cross-arms, transformers and other distribution assets. Pettigrew Rebuttal at 8. An excerpt from the Company's December 14, 2008 presentation in DPU 07-30, AG1-6, Attachment 2 reflects that the "I & M Program," which the Company claims is "new," in fact, "began as far back as 2006, perhaps earlier." Hahn Direct Testimony at 8 & RSH-10.

The Company, moreover, concedes that the purpose of the I & M strategy is to realize substantial gains in service reliability. Pettigrew Direct at 28. As detailed above in connection with the Company's vegetation management program, SAIDI and SAIFI metrics indicate that the Company's current system is "top-performing" in terms of reliability, and was so, well before the test year. Pettigrew Direct at 6.

Mr. Hahn, concurred:

> The Company has not provided adequate justification for the proposed increased spending on I & M activities. System reliability today is good, so the current test year level of spending seems to be producing good results.

Hahn Surrebuttal at 7-8.

Lastly, the Record reflects, and the Company does not dispute, that it expended significant sums of money in the past that improved the quality and reliability of its distribution assets. Hahn Surrebuttal at 5. In light of these improvements, the proposed inspections make little sense:

> [Y]et after having made these improvements, the Company proposes to inspect every distribution asset every five years. This would seem to cover circuits that have been recently upgraded under the Feeder Hardening program and other investments made by the Company. It isn't clear . . . why a circuit that has been recently upgraded . . . needs to be inspected within the next five years. Similarly, . . . It is equally unclear . . . why the Company needs to inspect utility poles that are less than 30 years old, which constitute 57% of the pole asset base.

Hahn Surrebuttal at 5-6. No basis exists to the Company claim that the incremental expenses associated with the I & M strategy are "necessary" to the services the Company provides. E.g., New England Tel. & Tel. Co., 446 A.2d at 1383. Indeed, the DPU recently flatly rejected the Company's request to recover its incremental I & M costs, along with a "separate reconciling adjustment" to recover these costs. Massachusetts Electric, D.P.U. 09-39 at 313.

Based on the aforementioned legal precedent and the Record, the Commission should adjust the Company's pro forma operations and maintenance expense downward by $2.094 million to eliminate proposed incremental expenses associated with the I & M program, and reject a separate reconciliation mechanism to recover these costs.

i. Affiliate Expenses

(i) Account 583

The Rhode Island Supreme Court has held that the "task of the commission is to base future rates on known and past present conditions…" Michaelson, 404 A.2d at 806. "All items of unusual magnitude which occurred during the test year, which are not expected to recur to a significant degree beyond the test year, should be adjusted to reflect what is reasonably to be expected in the future." Rules of Practice and Procedure, Rule 2.6 (c)(1). See Providence Gas, Docket No. 2082, Order No. 14311 at 32-33 (it is not appropriate to fully fund the maximum potential exposure where a requested amount does not represent known and measurable costs that will be incurred in the rate year).

The Commission has also recognized that "shareholders must be responsible for that portion of a program or plan that only benefits them." Providence Gas, Docket No. 2286, Order No. 14859 at 35. Thus, when a utility program or plan does not directly benefit ratepayers, the Commission should disallow expenses associated with the program or plan. Providence Gas, 656 A.2d at 951; Rhode Island Consumers' Council, 322 A.2d at 25. See also Entergy Arkansas, 289 S.W.2d at 525 (before a legitimate operational expense for an electric utility is included in rates it must have direct ratepayer benefit).

The test year includes large costs resulting from charges from the Service Company in Account 583. The Company's rate year expenses in Account 583 neither possess the requisite direct ratepayer benefit nor reflect reasonable known and measurable costs that will be incurred in the rate year.

The Company does not dispute that the costs for Account 583 increased from $2.8 million in 2007 to $5.1 million in 2008 or (46%) while the same account only increased 2% for comparable companies over the same time-period. Smith Direct at 12, 16. Nor does the Company dispute that costs for the overhead Geographic Information Survey ("GIS") project—the principal driver of this increase—will not recur in the rate year. Id. Rather, the Company merely asserts that the overhead GIS is a "precursor to" a multi-year new program that will update underground GIS data, the costs of which "will continue into future years." Pettigrew Rebuttal at 22.

The new program described by the Company is a pilot program the intent of which is to determine whether the Company will engage in an enhancement of its Underground GIS. 11/3/2009 Tr. at 52. There is no evidence that a full underground GIS program will be undertaken or how much it will cost. A generalized assertion that the Company's duplicate spending on the GIS program fails to meet the Company's burden to show that its requested rate year costs are known and measurable. E.g., Michaelson, 404 A.2d at 806.

The GIS project is designed on the basis of the needs of the New England National Grid electric distributions companies as a whole. The Service Company, not the Company, incurs costs associated with the project. The Company has not remotely explained how the requested incremental costs—particularly in light of their magnitude—provide any benefit to the *Company's* ratepayers. Again, the Company has failed to satisfy its legal burden to show that these costs provide a direct ratepayer benefit. E.g., Providence Gas, 656 A.2d at 951. The Commission should disallow these costs ($2.3 million) from the Company's rate year cost of service.

(ii) Account 588

Test year expenses in Account 588 suffer from similar legal and evidentiary defects. 2007 costs rose by 22% to approximately $1.6 million in 2008. According to the Company, this increase was associated with a program entitled "Electricity Distribution Transformation Program," Resp. to Div. Data Request 1-29, which was intended to "improve customer satisfaction" by boosting "reliability to the top quartile," Smith Direct at 17. Program expenditures, in turn, were to "inure to the benefit of customers." Pettigrew Rebuttal at 23-24.

Reliability metrics for the Company, however, reflect that the Company was already in the "1st quartile performance of other companies who participated in the IEEE Benchmarking study for 2007." Division Exhibit 18. Moreover, the general averment that customers may benefit at some time in the future as a consequence of incurring an expense, Pettigrew Rebuttal at 24, does not allege the sufficient direct benefit to ratepayers so as to legally support rate recovery for the Company for the expense. E.g., Providence Gas, 656 A.2d at 951.

The Division has recommended that the Commission disallow $.8 million to Account 588 or one-half of the 2008 cost of the Transformation Program. The disallowance still affords the Company a 12% increase from 2007 to 2008 for Account 588, an amount sufficient to reflect any incidental yet unproven benefit that may inure to ratepayers from the program in the rate year. The Commission should adopt the Division's recommendation.

j. Storm Fund Accrual

The Division has recommended that the Commission suspend the storm fund accrual of $1.041 million based on the magnitude of the present balance in the fund (a surplus of $21.692 million as of May 31, 2009), Resp. to Comm'n Data Request 1-107, and the accrual of interest and attachment fee revenue, which together exceed $1 million per year. Resp. to Div. Data Request 27-6 at 1. The balance is "more than adequate to provide for all but the most catastrophic storms," Effron Direct at 16, as shown by data that the Company produced in response in Resp. to Div. Data Request 27-6. Over the past decade, the annual charge to the storm fund account has not exceeded $1,310,550. In fact in five of the last ten years the fund did not sustain a charge at all, and the current surplus in the account of $21.7 million is more than the total storm damage charges of $17.8 million for the 27 years 1982-2008. Effron Surrebuttal at 4; Resp. to Div. Data Request 27-6 at 1. Lastly, current annual interest and attachment fee revenue "is greater than the average storm damage costs charged against the fund over the years 1982- 2008." Effron Surrebuttal at 4-5.

Initially, the Company opposed the Division's recommendation to suspend the storm fund accrual. However, at hearing, the Company's consultant, Robert O'Brien, admitted that if suspension were conditioned with a reinstatement threshold of $15 million, the Division's recommendation would provide relief to customers while ensuring the adequacy of the fund in future years:

> Q. In light of the current economy where Rhode Island has one of the highest unemployment rates in the country and many people can barely afford their electric bill...do you think that it would be harmful to the company if the Commission were to suspend funding of that storm fund for a couple of years...?
>
> A. ...I don't know what the right amount is...if the Commission were . . . to suspend the payment of the $1 million, I would suggest that the Commission establish a threshold of fund balance where the $1 million would be reinstated. For example, if we had a storm that drove the fund balance below $15 million . . . the [C]ompany can start charging for that $1 million again to build it back up. Something like that would give some relief today but also put a floor on what would be in the fund for future storms as they come through.

11/5/2009 Tr. at 31. This testimony reflects an implicit concession on a part of the Company that the Division's recommendation—suspension of the Storm Fund accrual—is reasonable and appropriate under current circumstances. The Commission, therefore, should reduce pro forma test year operation and maintenance expense by $1,041,000.

k. Storm Damage Expense

This Commission has held that "general rates should be based on expenses and risks that are likely to recur in the future." Filing Made by the Narragansett Electric Co., Docket No. 1350, Order No. 9747 at 7 (December 30, 1978). See Rhode Island Consumers' Council, 322 A.2d at 22 (the Commission may only give effect to "known and measurable" changes occurring after the test year); Harsch, 368 A.2d at 1207.

Thus, when an item "can be classified as nonrecurring in nature because [it] cannot be determined with any degree of accuracy when [it] would specifically occur again . . . it is disallowed for ratemaking purposes." Id. A five-year average reflects the normal annual storm expense that the Company can expect to incur over time, and is a time-period that the Commission denominated as appropriate to normalize expenses or revenue items that fluctuate widely from year-to-year. See Pawtucket Water, Docket No. 3497, Order No. 17574 at 28 (using 5 year period to normalize wholesale water sales).

The Division adjusted the Company's requested storm damage expense based on precisely these regulatory principles. Mr. Effron testified:

> The storm damage costs charged to expense vary widely from year to year. The expense included in the revenue requirement should reflect a normal level of expense that the Company can reasonably expect to incur on a prospective basis.

Effron Direct at 17-18.

The Company reported storm costs charged to operations and maintenance expense for CY 2004, \$437,428; for CY 2005, \$3,255,620; for CY 2006, \$4,113,601; for CY 2007, \$2,860,288; and for CY 2008, \$4,410,000. See Company Response to Div 23-1B (corrected by O'Brien Rebuttal at 15). The average of these figures is \$3.015 million. Mr. Effron appropriately reduced the Company's pro forma test year operation an maintenance expenses by \$1.395 million "to normalize test year storm damage expense." Effron Surrebuttal at 6.

I. Injuries And Damages

Rule 2.6(c)(1) of the Commission's Rules of Practice and Procedure requires that the "test year *must be normalized* to reflect expected results for the rate year" (emphasis added). The rule proceeds to require the following:

> All items of unusual magnitude, which occurred during the test year, but which are not expected to recur to a significant degree beyond the test year, should be adjusted to reflect what is reasonably to be expected in the future.

Id. The Rhode Island Supreme Court has enunciated the principles upon which this rule is based, explaining:

> If the test period used does not reflect the present operating experience of the company and the reasonably expected future economic conditions which the company will be confronted with, or if adjustments in the test period are not made so as to take these two factors into consideration and give effect to them, the rate-making process does not and cannot become an honest and intelligent forecast of probable conditions of the company in and during a reasonable period in the immediate future [citations omitted].

Harsch, 368 A.2d at 1207.

In the pending matter, the Company's 2008 claims reserve exceeded the amount reserved in 2007 by $2.5 million, Resp. to Div. Data Request 1-29 at 2 (commentary). This increase reflected the accrual of payments that the Company anticipated it would make in the future on a settlement of litigation involving the injury of an individual that occurred in 2004. Effron Surrebuttal at 7; Resp. to Div. Data Request 23-3.

The Company contends that the $2.5 million is an expense that it "will likely incur again," O'Brien Rebuttal at 17. Mr. O'Brien could not cite any example, past or future, of similar expenses. 11/5/2009 Tr. at 10. Nor did the Company provide any other "evidence of accruals of similar magnitude to the $2.5 million for any discrete events in recent years" or descriptions of events which would result in similar accruals prospectively. Effron Surrebuttal at 7.

By contrast, Mr. Effron, testified that the average injuries and damage expense for the period 2004-2008, including the $2.5 million accrual booked in 2008, was $4.685 million: the average of $3.881 million in 2004, $2.244 million in 2005, $6.360 million in 2006, $3.888 million in 2007 and $7.055 million in 2008. Effron Surrebuttal at 8. The $4.685 million figure, Mr. Effron testified, "confirms the reasonableness of the Division's pro forma Injuries and Damages expense recommendation ($4.555 million). Id. No factual or legal basis exists to support the Company's claim for injuries and damages expense. "Adjustments in rate cases cannot rest on conjecture." Rhode Island Consumers' Council, 302 A.2d at 767. The Commission should adjust the Company's pro forma test year injuries and damages expense downward by $2.5 million.

m. Outside Legal Fees

This Commission has held that when a requested amount does not represent known and measurable costs that will be incurred in the rate year, it is not appropriate for the Commission to fully fund the maximum potential exposure. Providence Gas Company, Docket No. 2082, Order No. 14311 at 32-33. Post-test year changes must be "known and measurable," Harsch, 368 A.2d at 1207. "...Allowed operating expenses are those expenses that the utility is required to pay and actually pays." Rhode Island Consumers' Council, 322 A.2d at 23.

In the pending matter, the Company concedes that the Forward Capacity Market ("FCM") Litigation involving Constellation Energy Commodities Group, Inc. has been resolved and will not reoccur. Nonetheless, the Company contends that expenses associated with that litigation should be included in its revenue requirement because there "will continue to be many instances where the Company will need to employ outside legal assistance to defend the interests of the Company." O'Brien Direct at 19.

The FCM Litigation was unique in the breadth of its subject matter and scope, occurring in four different fora, the United States District Courts for the Districts of Rhode Island and Massachusetts, the Federal Energy Regulatory Commission ("FERC"), and the First Circuit Court of Appeals, and involving the interpretation of various provisions contained in four different Power Purchase Agreements as well as a FERC approved settlement agreement.[11] The

[11] The litigation included, among other proceedings, the following matters: (i) In Re: The Narragansett Electric Company v. Constellation Energy Commodities Group, Inc., C.A. No. 06-404, (ii) Constellation Commodities

uniqueness of the FCM Litigation makes reoccurrence of litigation of similar magnitude within the rate year highly improbable. Mr. O'Brien was unable to provide examples of similar expense. 11/5/2009 Tr. at 11-12. Nor has the Company presented any other evidence whatsoever (*i.e.*, pending litigation of similar scope and magnitude) that would require the Company to incur a similar level of outside legal expenses in the rate year. A general averment that there will be "many instances" where the Company will need to retain outside counsel at some unknown period in the future is legally insufficient to support the Company's claimed level of legal expense. See e.g., Harsch, 368 A.2d at 1207; Rhode Island Consumers' Council, 322 A.2d at 23. The Commission, therefore, should reduce the Company's pro forma test year legal expenses by $419,000, as recommended by the Division,

n. ISO Load Response Credit

Test year expenses must be reduced in order to reflect receipt of a credit. Michaelson, 404 A.2d at 806 (commission should make post-test-year expenses changes that affect test-year results with certainty); Rhode Island Consumer's Council, 322 A.2d at 22. In the pending matter, the Company concedes that it received a credit of $300,000 in 2009 that was applicable to 2008 expenses yet nowhere in its rebuttal testimony does the Company discuss its continued opposition to this recommended adjustment to its test year operating and maintenance expense. The Company, therefore, must be deemed to have adopted the Division's recommended adjustment. See e.g., Gilbane Building Co. v. Ocean State Building & Wrecking, Inc., 748 A.2d 826, 828 (R.I. 2000) (failure to waive issue before trial judge constitutes waiver of issue). The Commission should reduce the Company's pro forma test year by $300,000.

Group, Inc. v. The Narragansett Electric Company, C.A. No. 400068FDS, (iii) In Re: Constellation's Petition for Declaratory Order, FERC El-07-000, and (iv) In Re: Constellation's Interlocutory Appeal, Appeal No. 08-1080.

o. Net Merger Synergy Savings – Cost To Achieve ("CTA")

The cost to achieve synergies allocable to the Company from the acquisition of Keyspan by National Grid USA is $16.005 million. Of this amount, $8.610 million occurred in Year 1 and Year 2 following the merger and has not been recovered from customers.

The Company has estimated total synergy savings realized during Years 1 and 2 from CTA at $9.471 million, Effron Direct at 23. Due to the rate freeze, shareholders, rather than customers, received the entire benefit of these savings.

The matching principle for ratemaking dictates that "*related* revenues and costs must match each other." Public Service Co. of Colorado v. Public Utilities Comm'n of State, 26 P.2d 1198, 1207 (Colo. 2001). Under this principle, the CTA incurred in Year 1 and Year 2 have more than paid for themselves by expense reductions retained by shareholders. Effron Direct at 23. That is, the $9.471 million in synergy savings in Years 1 and 2 has been "more than adequate to absorb the CTA incurred in those years." Effron Surrebuttal at 9. Therefore, there is no need to recover the $8.610 million incurred in Years 1 and 2 prospectively.

The remaining CTA of $7.395 million amortized over eight years results in an annual CTA expense of $924,000 or $1.176 million less than the Company's proposed CTA amortization of $2.1 million. The Commission should reduce the Company's pro forma rate year expense by $1.176 million.[12]

[12] As set forth in the Surrebuttal Testimony of Mr. Effron, the Division maintains that in any rate case after four years from the present case, the Commission should require "proof of continuing savings in order for the Company to continue to include the shared savings line item in its revenue requirement." Effron Surrebuttal at 11. See Narragansett Electric, Docket No. 3943, Order No. 19563 (where the Commission approved a stipulation that required a proof of savings for any rate case filed five years from the date of the Commission's Order).

3. Uncollectible Accounts Expense

a. Transmission-related

Mr. Effron testified that "[u]ncollectible accounts expenses related to distribution service are assigned to the distribution cost of service, and uncollectible accounts expenses related to transmission service should be assigned to the transmission cost of service." Effron Direct at 13. The Company's principal witness, Mr. O'Brien, agreed with Mr. Effron:

> I concur with Mr. Effron that the Company's transmission cost of service should include uncollectible accounts expense related to its transmission charge revenues and that they should be recovered as a component of the transmission charge rather than the current practice of including recovery of such costs in the Company's distribution rates.

O'Brien Rebuttal at 21. The entirety of the evidence on the Record, therefore, supports the Division's recommendation removing transmission related uncollectible accounts from the distribution revenue requirement in the pending docket.[13]

b. Commodity-related

In Providence Gas, Docket No. 3943, Order No. 19563 at 50, this Commission declined to approve the Company's proposed gas-cost related bad debt reconciling mechanism. The Commission explained:

> The Commission declines, however to approve the proposed gas-related bad debt reconciling mechanism. The Commission has historically used a multi-year average of the Company's actual experience in base rates in order to mitigate year to year variations, and finds that annual reconciliation of commodity-related bad debt cost is not in the best interest of ratepayers because it has the potential to amplify price volatility for customers [citations omitted]. Fixing the commodity-related bad debt ratio in base rates is not inconsistent

[13] The Company attempts to calculate transmission related uncollectible accounts expense at $1.361 million though it concedes that this amount "should be reconciled to actual transmission charge-related uncollectible accounts expense annually." O'Brien Rebuttal at 22. The Division does *not* concur. Transmission-related uncollectible accounts expense should be calculated "when the Company's transmission rates are set." Effron Surrebuttal at 4.

> with the Commission's treatment of commodity costs, which are recovered on a pass-through basis, because the Company has the ability to develop and implement measures to lower the uncollectible ratio.

Id.

In the pending matter, the Company proposes to recover commodity-related uncollectibles account expense through a fully reconciling rate adjustment mechanism that would be incorporated into the Company's Standard Offer Service ("SOS") rates. O'Brien Direct at 64. The Commission rejected a similar proposal in Docket No. 3943, and should do so again in this docket. Providence Gas, Docket No. 3943, Order No. 19563 at 50. Consistent with the Commission's ruling in Docket No. 3943, the overall bad debt rate that the Commission approves in the instant proceeding "should be used to determine the level of uncollectible accounts expense to be included in the SOS rate." Oliver Direct at 79.

c. *Delivery-related*[14]

The Division has recommended that the Commission approve a bad debt ratio of .71% for both distribution and commodity related service, or $4.864 million less than the Company's requested bad debt ratio of 1.16%. Gay Direct at 25. Legal precedent and the evidentiary Record support the Division's recommendation.

This Commission has repeatedly admonished the Company to become more "proactive in its collections activity . . . When a customer's balance exceeds $1,000, the Company should either have the customer significantly reduce his balance with a payment or . . . his service should end." In Re: New England Gas Co.'s Gas Cost Charge, Docket No. 3436 Order No.

[14] The Division continues to oppose the Company's proposed distribution adjustment tariff provision. Mr. Effron testified that the purpose of the provision's language, "was to allow the [Company] to adjust rates for exogenous events that might occur during the term of the five year rate freeze, because the [Company] was otherwise prohibited from adjusting rates." Effron Direct at 35. Since the pending matter does not concern a freeze of the Company's rates, such a tariff provision to address exogenous events is unnecessary. Id.

17606 (November 21, 2003). A customer's "failure to pay," his or her utility bill, this Commission warned, "must have consequences . . . or else all other bill paying customers . . . [will] suffer the consequences of higher rates." New England Gas, Docket No. 3436, Order No. 17970 at 10-11 (August 20, 2004). Recognizing the necessity of utilities to proactively manage their uncollectibles, commissions have reduced utilities' bad debt allowance percentages in order to encourage the companies "to develop and implement measures to lower its uncollectible ratio." See Providence Gas, Docket No. 3943, Order No. 19563 at 50.

In Patton v. South Carolina Public Service Comm'n, 312 S.E.2d 257, 258 (S.C. 1984), a utility filed an application for an increase in rates, which the South Carolina Public Service Commission approved, but in an amount lower than that requested by the utility. In its order, the Commission concluded that uncollectibles expense should be set at 1% of revenues even though the record reflected the actual percentage was much higher than 1%." Id. at 259. The utility appealed, contesting the "reasonableness" of the Commission's decision. Id. at 260.

On appeal, the Supreme Court of South Carolina upheld the decision of the Commission establishing an allowance of uncollectible expense of 1% of revenues even though the record revealed that the "actual percentage" was "higher than 1%." Id. at 259. The Commission's ruling to give the utility such an allowance was well within the Commission's statutory authority to supervise and regulate rates and service of public utilities. Id. The Court then proceeded to find:

> the Commission's allowance of an uncollectible expense of 1% of revenues provides an incentive for the utility to engage in good business practices and pursue payment on past due accounts rather than including these as an expense to be borne by other ratepayers.

Id.

The Company, too, has recognized that imprudent management over accounts receivables may necessitate a reduced bad debt allowance percentage. In In Re: EnergyNorth Natural Gas, Inc. d/b/a National Grid NH, DG 08-009, Order No. 24,872 (May 29, 2009), the New Hampshire Public Service Commission's Staff had recommended that the Company's bad debt expense [was] extremely high compared to New Hampshire utilities "as a result of poor collection practices." Rebuttal Testimony of Gary W. Bennett at 11. Staff had recommended only limited recovery of those expenses reducing the Company's proposed bad debt allowance percentage from 2.54% to 1.54%. Id. The Company's New Hampshire gas affiliate insisted that the reduction was unwarranted, id., but nonetheless accepted as part of a partial settlement bad debt allowance percentages that declined on a yearly basis over the four-year period from the 2.54% in 2009-10 to 1.75% in 2012-13. EnergyNorth, DG 08-009, Order No. 24,872 at 8.

In the pending matter, all of the evidence reflects that had the Company broadened and accelerated its disconnection activities on residential and non-residential accounts, the Company could have reduced its charge-offs in 2007, 2008 and 2009. The Company concedes that it did not implement a bad debt mitigation strategy until "more like mid" 2008, including but not limited to failing to implement outbound calls for non-residential until November, 2008. 11/6/2009 Tr. at 47; Gay Direct, 14, 17. Upon their implementation, the strategies failed to include the use of standard risk mitigation techniques (*e.g.*, security deposits or late fees on residential customers) and minimally implemented security deposits or negotiated payment arrangements on active, delinquent non-residential accounts. Gay Surrebuttal at 8-9.

The Company also concedes that it did not terminate any standard customers (regardless) of their outstanding balance during the 2007-2008 moratorium period, and only five standard customers were terminated during the moratorium period of 2008-2009. Division Exhibit 23. The Company permitted hundreds of standard customer residential accounts to exceed 150 days past due without disconnection. Gay Direct at 24, with balances ranging from $650 to as high at $17,100. Division Exhibit 24. The Company also permitted hundreds of non-residential accounts to exceed 90 days past due, again without disconnection. Gay Direct at 24. As a consequence, the scope and manner of the Company's delinquent portfolios management was unreasonable and imprudent. Gay Surrebuttal at 8. The Commission should reduce the Company's uncollectible accounts expense by $2.933 million, which will provide the Company with an incentive to "to develop and implement measures to lower its uncollectible ratio." Providence Gas, Docket No. 3943, Order No. 19563 at 50.

D. REVENUE DECOUPLING RATEMAKING ("RDR") PLAN

The Company has proposed a RDR Plan, which consists of "Look Back" and "Look Ahead" components, which combine to produce an RDR Plan Adjustment Factor. Embedded within the "Look Ahead" and "Look Back" components, are three subcomponents: (a) an annual capital expenditures tracker, (b) an annual adjustment for inflation on operating expenses, and (c) an annual revenue reconciliation mechanism ("Revenue Decoupling").[15] Tierney Direct at 77. When added to base distribution rates, the Adjustment Factor produces class distribution rates. Id. at 17.

According to the Company, nationwide Revenue Decoupling reflects a "less common" but "growing" trend for electric utilities nationwide. Id. at 49. At the local level, the Company contends that Revenue Decoupling "is grounded in long-standing Rhode Island ratemaking policy and practice." Id. at 4. The Company further assures the Commission that its Revenue Decoupling proposal is structured so that it "does not over-collect or under-collect" the Company's allowed revenue requirement. Id. at 4.

As will be seen, for electric utilities nationwide, both the RDR Plan and Revenue Decoupling represent the minority position. In Rhode Island, neither the RDR Plan as a whole

[15] As used in this Brief, the term RDR Plan refers to the Company's RDR Plan in its entirety with all of components. The term "Revenue Decoupling" refers solely to that subcomponent of the "Look Back" and "Look Ahead" features of the RDR Plan that represents the annual revenue reconciliation mechanism.

nor Revenue Decoupling is "grounded in long-standing Rhode Island ratemaking policy and practice." Id.

Features of the RDR Plan run afoul of statutory and/or regulatory principles as well. The General Assembly has not authorized the Commission to implement, nor does the Commission possess the authority under its Rules to approve, the annual inflation adjustment on operating expenses. Moreover, both "Look Back" and "Look Forward" components of the RDR Plan and Revenue Decoupling possess features that violate the regulatory requirement that rate recovery of capital expenses may not commence until the relevant asset is "used and useful."

1. For Electric Utilities Nationwide Both The RDR Plan And Revenue Decoupling Represent The Minority Position.

In an effort to obtain Commission support for its RDR Plan and Revenue Decoupling, the Company implies that decoupling is a "prevalent" and "grow[ing]" ratemaking methodology across the nation. Id. at 49-50. A survey of the fifty states for electric utilities reflects that the RDR Plan is the overwhelming minority position. Revenue Decoupling, moreover, rather than a growing trend, has been rejected by a number of jurisdictions that had previously adopted some form of decoupling.

Of the fifty States only three electric utilities in California have adopted a revenue decoupling plan remotely similar to the RDR Plan. The six other States (other than Calfornia) identified by the Company as "rely[ing] on rate mechanisms that incorporate revenue decoupling," Tierney Direct at 49, (Connecticut, Idaho, Maryland, New York, Oregon, and Wisconsin) do *not* permit the annual recovery of capital expenditures or inflation. Application of the United Illuminating Co. to Increase its Rates and Charges, Docket No. 08-07-04, (February 4, 2009) In Re: Matter of Investigation of Financial Incentives to Investment in Efficiency by Idaho Power Co., Case No. IPC-E-04-15, Order No. 30267 (March 12, 2007); In Re:

Application of Delmarva Power & Light Co. for Authority to Revises its Rates and Charges for Electric Service and for Certain Rate Design Changes, Case No. 9093, Order No. 81518 (July 19, 2007); Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Co. of New York, Inc. for Electric Service, Case 07-E-0523 (March 25, 2008); In Re: Portland General Electric Co., Order No. 09-176 (May 19, 2009); In Re: Wisconsin Public Service Corp. for Authority to Adjust Electric and Natural Gas Rates, 6690-UR-119 (December 30, 2008).

Of these States, plans of utilities in Idaho and Wisconsin are solely "Pilot Programs" that expire in 2010, 2010 and 2012, respectively. Idaho Power Co., Case No. IPC-E-04-15, Order No. 30267 at 18; In Re: Wisconsin Public Service Corp. 6690-UR-119 at 26. The Oregon, Idaho and Maryland programs contain caps of (2%, 3% and 10%, respectively) that limit the magnitude of the possible annual adjustment. Portland General Electric Co., Order No. 09-176 at 5; Idaho Power Co., Case No. IPC-E-04-15, Order No. 30267 at 13; Delmarva Power & Light Co., Case No. 9093, Order No. 81518 at 50 (July 19, 2007).

Four States have rejected decoupling for electric utilities: Maine, Florida, New Mexico and Washington. Maine Public Utilities Comm'n Report on Utility Incentives Mechanisms for the Promotion of Energy Efficiency and System Reliability, at 26 (February 1, 2004); Report to the Legislature on Utility Revenue Decoupling at 23-25 (Fla. December, 2008); In re: Petition of Public Service Co. of New Mexico for Revision of its Rates, Rules and Charges Pursuant to Advice Notice Nos. 755 and 756, Case No. 06-00210-UT at 39 (July 2, 2007); Washington Utilities Transp. Comm'n v. Pacificorp d/b/a Pacific Power & Light Co., Docket UE-050784, Order 3 (April 17, 2006).

In 2008, the Florida Legislature requested the Florida Public Service Commission ("FPSC") to provide a report and recommendations regarding a three-year revenue decoupling program that had been in place between 1994 and 1997. Basing its conclusions on measurement criteria that had been adopted during the program, the FPSC observed, "questions remain as to whether decoupling is a prerequisite to encourage conservation." Florida Report at 25. "...[T]he greatest impact of the decoupling experiment was the neutralization of variances in the utility's revenues due to variations in weather," not due to energy conservation. Id. at 24. See also Petition by New Mexico Public Service Co., Case No. 06-00210-UT at 39-40. Indeed during the program, a utility exceeded its megawatt goals without the benefit of decoupling. Florida Report at 24.

In 1991, the State of Maine initiated a three-year decoupling program for Central Maine Power Company ("CMP"). Under the program the allowed revenue was adjusted annually based on changes in the utility's number of customers. A recession at the time resulted in lower sales, which, in turn, resulted in revenue deferrals. By the end of 1992, deferrals under the plan had reached $52 Million. Maine Report at 26-27. "The consensus was that only a very small portion of this amount was due to CMP's conservation efforts and that the vast majority of the deferral resulted from the economic recession." Id. at 27. Conservation and energy efficiency [were] "driven more by customer decisions than by utility action." Id. at 7. Thus, according to the Commission the mechanism was:

> increasingly viewed . . . as shielding CMP against the economic impact of recession, rather than providing the intended energy and efficiency and conservation incentive impact.

Id. Not only did Maine's experiment with decoupling come to an end in 1993 but also the Commission reported to the Legislature the following year that programs such as decoupling "are likely to have ancillary consequences that could, in the Commission's view, create substantial adverse effects." Id. at 5.

2. <u>The RDR Plan And Revenue Decoupling Are Not Grounded "In Long-Standing Rhode Island Ratemaking Policy And Practice."</u>

The Company's RDR Plan and Revenue Decoupling are also not grounded in "long-standing Rhode Island rate making policy and practice." This Commission has never before had the opportunity to address the merits of any plan remotely resembling the Company's proposed RDR Plan. Nor has this Commission ever approved of adjustment mechanisms in other proceedings that remotely resemble the individual components of the RDR Plan: that is, the Commission has never approved an annual adjustment mechanism for inflation; the capital tracker that the Commission did approve in Docket No. 3943 was implemented due to safety and environmental concerns—concerns that are not present in the pending matter; and lastly, the Commission flatly rejected Revenue Decoupling in Docket No. 3943.

In Docket No. 3943, the Commission approved an accelerated replacement program ("ARP") finding 900 miles of cast iron main, 440 miles of unprotected bare steel main and 240 miles of unprotected coated bare steel main, and about 8,261 high pressure, bare-steel services, all of which are prone to gas leaks that "create safety and environmental issues" for gas company customers. <u>Narragansett Electric</u>, Docket No. 3943, Order No. 19563 at 48. More specifically, the evidence reflected leakage rates in Rhode Island seven times higher than in upstate New York. <u>Id.</u> at 47. The continuing presence of cast iron and bare steel in the Company's gas distribution system had produced leaks that had resulted in a number of explosions in Rhode Island over the past ten years.

In the pending matter, by contrast, the Company has not presented any evidence of potential or probable customer injury relating to a specific condition in its network. The Record is utterly devoid of any safety or environmental issue relating to the Company's electric distribution system that would necessitate a capital program and tracker similar to those adopted by the Commission in Docket No. 3943. Rhode Island ratemaking policy and practice, long-standing or otherwise, does not support the adoption of the Company's capital expenditure tracker.

In Narragansett Electric, Docket No. 3943, Order No. 19563, this Commission also addressed Revenue Decoupling. Finding that "[r]egardless of decoupling, most customers have an incentive to conserve because reduced usage translates directly into lower commodity charges . . . which account for over two thirds of the average residential bill," id. at 69-70, this Commission held that the adoption of "[r]evenue decoupling would protect the Company from revenue declines attributable to *any cause*, not only energy conservation and efficiency efforts." Id. (emphasis added). The Commission, thus, flatly rejected Revenue Decoupling. Revenue Decoupling, then, also is not grounded in Rhode Island ratemaking policy or practice, long-standing or otherwise.

3. **The Commission Does Not Possess The Authority To Implement An Annual Inflation Adjustment Mechanism.**

The Rhode Island Supreme Court has held that when the terms of a statute are "plain and unambiguous," full effect must be given to the plain and ordinary meaning thereof. E.g., Brule v. Kilduff, 524 A.2d 593, 594 (R.I. 1987). G.L. § 39-1-27.7(d) provides in full as follows:

> If the commission shall determine that the implementation of system reliability and energy efficiency and conservation procurement has caused or is likely to cause under or over-recovery of *overhead* and *fixed costs* of the company implementing said procurement, the commission may establish a mandatory rate adjustment clause for the company so affected in order to provide for full recovery of reasonable and prudent *overhead* and *fixed costs.*

(Emphasis added).

By its plain an unambiguous terms, G.L. § 39-1-27.7(d) permits the Commission to provide a "rate adjustment clause" for the recovery of "overhead" and "fixed costs." "Fixed costs" are costs that remain (more or less) constant irrespective of the output level or sales revenue of the firm (*e.g.*, rent and salaries). Black's Law Dictionary (8th ed. 2004). "Overhead" are costs that relate to the operation or the firm as a whole, is not included in direct labor, materials or administrative costs, and cannot be applied or traced to any specific unit of output (*e.g.*, utility charges). Id. The term "inflation," by contrast, is not "overhead" or a "fixed cost" but rather refers to a "sustained, rapid increase in the general price level, as measured by some broad index. BusinessDictionary.com. Plainly, the Commission does not possess any authority under G.L. § 39-1-27.7(d) to establish an annual inflation adjustment mechanism.

Nor do the Commission's own rules permit the Commission to grant annual inflation adjustments on operating expenses in the context of a reconciliation tariff filing. Pursuant Rule 2.6(c)(4), "inflationary adjustments" based on projected cost increases such as Consumer Price Increases are prohibited unless the utility presents a "cost of service for a test year period," which must consist of a "historic year of actual data," typically for a period ending within nine months of the filing date. Commission's Rules of Practice, Rule 2.6(a) (1998). Under the Commission's rules, then, inflation adjustments are *per se* barred outside the traditional rate-setting process.

Absent statutory authority to authorize an annual inflation adjustment mechanism, the Commission's rules are fatal to the Company's request to receive such a mechanism in the pending matter. All judicial authorities agree that "[a]n agency has an obligation to abide by its own regulations." Rotinsulu v. Mukasey, 515 F.3d 68, 72 (1st Cir. 2008). "The failure to follow an applicable regulation may be a sufficient ground for vacation of an agency's decision..." Id. See also FCC v. Fox Television Stations, Inc., 129 S.Ct.1800, 1811 (2009) ("[a]n agency may not . . . depart from prior policy *sub silentio* or simply disregard rules that are still on the books"). The Commission does not possess authority to grant the Company an annual inflation adjustment mechanism either pursuant to G.L. § 39-1-27.7(d) or pursuant to its own rules. The Company's request to receive such a mechanism, accordingly, must fail.

4. **The Commission Does Not Possess The Authority To Implement The RDR Plan Which Allows Recovery Of Capital Expenditures That Are Not "Used And Useful."**

The Rhode Island Supreme Court has held that a "utility cannot expect a customer to pay for property not used in the rendition of services." Newport Electric Corp. v. Public Utilities Comm'n, 624 A.2d 1098, 1103 (R.I. 1993). See also Valley Gas Co. v. Burke, 406 A.2d 366, 371 (R.I.1979). Thus, costs that reflect the potential for an investment are not invested in any used and useful property, and to the extent the utility attempts to include these payments in its rate base, the court will not allow such a "maneuver." Newport Electric, 624 A.2d at 1103. See also Providence Gas Co. v. Burke, 448 A.2d 773, 774 n. 2 (R.I. 1982) (the defined "rate base" as the utility's total investment in, or the fair market value of, the "used and useful property necessarily devoted to the rendering of the regulated service").

Under its RDR Plan proposal, the Company's July and November filings for 2010 (effective January 1, 2011) will contain its estimated capital expenditures for October, November and December, 2010. Tierney Direct at 94. In connection with this component of the RDR Plan, the Company's consultant, Dr. Susan Tierney, stated "...we are building into rates an allowance for recovery of revenue to support investment..." 11/4/2009 Tr. at 50. Dr. Tierney then conceded, "there could be dollar[s] associated with collection of a rate today for something that actually goes into service tomorrow because of a timing difference." 11/4/2009 Tr. at 51. The Division's expert consultant, Mr. Bruce R. Oliver, confirmed that the prudent, used and useful standard requires "such determinations be made before costs for capital additions are included in rates." Oliver Direct at 47. The "Look Ahead" portion of the Company's RDR Plan is not consistent with this requirement. Id.

G.L. § 39-1-27.7(d) permits the Commission to establish a "mandatory rate adjustment clause" to provide for the "full recovery of reasonable and prudent overhead and fixed costs." The statute, however, does not authorize the Commission to establish or the Company to recover costs through a reconciliation mechanism of assets that are not "used and useful."

When the General Assembly enacts a statute, "it is presumed to know existing relevant law." State v. Briggs, 934 A.2d 811, 814 (R.I. 2007); Peck v. Jonathan Michael Builders, Inc., 940 A.2d 640, 643 (R.I. 2008). Thus, when it enacted § 39-1-27.7(d), the General Assembly would have known of the bar against the recovery of costs of a utility's assets that are not used and useful. It follows that the General Assembly would have *expressly* authorized the recovery of costs for such assets in § 39-1-27.7(d) if the reconciliation adjustment mechanism contained in the statue sanctioned the recovery of such costs. G.L. § 39-1-27.7(d) does not authorize a reconciliation adjustment like the "Look Forward" component of the RDR Plan that permits the recovery of capital expenditures that are not "used and useful." The Company's request for the Commission to implement such a mechanism, therefore, must be denied.

5. The Company Has Not Demonstrated A Need For A Capital Tracking Mechanism.

As part of its RDR Plan, the Company proposes to implement a capital tracking mechanism, which will enable the Company to recover its annual capital expenditures. The Company, however, has not demonstrated that it needs to increase its level of capital expenditures, or that it cannot meet its proposed capital budgets without a capital tracking mechanism. See supra Part III(C)(1)(a). Mr. Hahn testified that the Company has already increased its investment dramatically to improve reliability. Hahn Direct at 15; 11/23/2009 Tr. at

37. Moreover, Mr. Hahn showed how the Company's alleged "ramp-up" of capital spending in the rate year was already supported by or incorporated into unadjusted test year data. Hahn Surrebuttal at 12-13.

Capital additions of the Company between 2006 and 2008 are presented in the following Table that is contained in the Surrebuttal Testimony of Mr. Hahn.

Table 1
Narragansett Electric Company
Capital Additions 2006 – 2008

Year	Transmission	Distribution	Total T&D	% change
2006	$638,517	$46,988,796	$47,627,313	
2007	$8,503,766	$47,892,648	$56,396,414	18%
2008	$31,788,587	$67,688,304	$99,476,891	76%
Adj TY	$31,788,587	$88,588,304	$120,376,891	113%

The Table reflects that the Company's 2008 test year spending supports distribution related additions of $67.6 million and total additions of $99.5 million. The Table also reflects if the $20.9 million in projects requested by the Company were included in the test year, the allowance for capital spending on distribution assets in that year would increase to $88.6 million (Adj. TY) and the allowance for total capital additions would increase to $120.4 million (Adj. TY). Hahn Surrebuttal at 13.

The Company's distribution capital budgets for 2009 and 2010, however, are only $60 million and $76 million, respectively. Thus, 2008 unadjusted test year costs already support capital additions anticipated by the Company's rate year capital budget. Id. at 12. Moreover, even if the proposed capital investments are made and the capital tracker is not implemented (as has historically been the case), the Company can still earn its allowed return if, for example, it increases efficiency (decreases expenses), and retires other plant.

The proposed capital tracking mechanism is both unsupported by the Record and unnecessary. The Commission, therefore, should deny the Company's proposal to implement such a mechanism as set forth in its RDR Plan.

6. <u>The Substantial Evidence On The Record Does Not Support The Company's Revenue Decoupling Proposal.</u>

a. Revenue Decoupling Will Not Enable Or Encourage The Company To Pursue Energy Efficiency And Conservation More Aggressively.

The Company also contends that adoption of Revenue Decoupling will: (i) eliminate an "indirect" disincentive for the Company to pursue energy efficiency and conservation programs by stabilizing revenue declines allegedly caused by such programs, <u>Tierney Direct</u> at 29-30, 35, 43, and (ii) create "positive incentives" for the Company to pursue energy efficiency more aggressively than ever. <u>Tierney Direct</u> at 36, 42.

State law, however, requires the Company to fund energy efficiency programs, as well as establishes standards for the eventual implementation of least cost procurement of energy efficiency and energy efficiency measures. Regardless of alleged financial motives, the Company is legally required to pursue energy efficiency and conservation and system reliability procurement. <u>See e.g.</u>, G.L. § 39-1-27.7(a) (requiring Commission to establish standards). <u>Stout Direct</u> at 4.

Commodity costs, moreover, represent a larger portion of a residential and small commercial customer's bill than do distribution costs. <u>Tierney Direct</u> at 38. Moreover, about 55% and 66% of the revenues of the Company's large and general, C & I customers, respectively, are derived from demand or customer charges. <u>Oliver Direct</u> at 30, DIV-BRO-1. Non-commercial customers will make every effort to conserve and implement efficiency programs in order to reduce commodity related costs regardless of the existence of Revenue

Decoupling, Narragansett Electric, Docket No. 3943, Order No. 19563 at 69-70, which only impacts the distribution portion of their bill. Tierney Direct at 38, 45. Revenues of large and general C & I customers are largely already decoupled from the Company's sales due to the fact that the bulk of their revenues are derived from demand or customer charges. Oliver Direct at 22, 30. Revenue Decoupling, then, will not incent customers to implement efficiency programs.

The Company, moreover, has not presented any evidence that it is not fulfilling its state mandated obligation to pursue energy efficiency and conservation measures. In fact, the Record reflects the opposite conclusion: the Company's shareholders possess substantial incentives to pursue energy efficiency programs regardless of decoupling and that the Company has been pursuing the implementation of energy efficiency and conservation programs as completely and aggressively as possible.

The Company's total electric DSM budget (including commitments and shareholder incentives) has increased from $23 million in 2008 to $32.4 million in 2009 and is projected at $43.9 million in 2010 including shareholder incentives and commitments. 11/4/2009 Tr. at 210-11; Energy Efficiency Program Plan ("EEPP") for 2010 (November 2, 2009), Table E-2,-8.[16] Shareholder incentives earned for 2008 and 2009 and 2010 were $675,000 and approximately $1.036 million, and are projected at $1.674 million, respectively. 2008 DSM Report, Table E-4; EEPP, Table E-2,-3. All funds allocated for energy efficiency in 2009 will be used. 11/4/2009 Tr. at 213. In fact, the Company anticipates a negative fund balance at the end of 2009 ($1,117,390), spending "in excess of sources of funds in 2009," EEPP at 22, and is committed to "making every attempt to spend or commit all funds available for DSM" in 2010. EEPP at 17. When asked whether this budget would change in the absence of Revenue Decoupling, the

[16] On December 23, 2009, the Commission rejected the 2010 EEPP, a multi-party settlement agreement, which would have increased the DSM charge to .6 mills per kWh, reasoning that customers should be spared any increases that can possibly be funded by some other means.

Company's principal witness, Timothy Stout, replied they would not. 11/4/2009 Tr. at 222. "Regardless of decoupling," Mr. Stout observed, "the programs will be effectively and well implemented." Id. at 232. No legal or factual basis, then, exists to support the Company's claims that the absence of Revenue Decoupling indirectly inhibits conservation or that the existence of Revenue Decoupling will provide the Company with an incentive to implement efficiency measures more aggressively. The Company's contentions in this regard are without merit.

b. Revenue Decoupling Creates Interclass And Intraclass Inequity.

The Rhode Island Supreme Court has held that the cost-of-service study may be a precondition to consideration of a proposed rate design. Rhode Island Consumer Council, 302 A.2d 757, 774 (R.I. 1973). The study ensures an "objective" means to ensure that the reasonableness of the rates to be assessed to each class of customer is based on cost of serving the various classes of customers. Public Utilities Comm'n, 393 A.2d at 1096.

The Company's Revenue Decoupling proposal uses a single uniform cents per-KWh rate adjustment for all classes. The proposal "greatly increases the potential for shifting revenue requirements among classes of service in a manner that is not supported or consistent with [the Company's] cost of providing service." Oliver Direct at 49. Thus, a uniform cents per-KWh adjustment across all classes will require a class that recovers more than its allocated costs to subsidize a class that falls short of it fully allocated revenue requirements. Oliver Direct at 49. The result is plainly barred by judicially sanctioned cost-of-service principles. Public Utilities Comm'n, 393 A.2d at 1096. Recovery of all reconciliation adjustments through a uniform cents-per-kWh charge for all classes also "will place a disproportionate share of the burden for such adjustments on customers within each class that have a comparatively large kWh requirements, regardless of their load factors or the comparative efficiency of their energy use," Oliver Direct at 50, again a result barred by this Commission. See In Re: Providence Gas Co., Filing Docket No. 1844, Order No. 12124 at 3 (November 27, 1985) (low load customers should be responsible for their respective fair share of costs). See also G.L. § 39-2-2 (barring rate discrimination); G.L. § 39-2-3 (barring unreasonable preferences or prejudices).

E. RATE DESIGN

1. Cost Allocation

This Commission has adopted cost causation as a general principle of rate design. E.g., Valley Gas Co., Docket No. 2276, Order No. 14834 at 27; Providence Gas, Docket No. 1844, Order No. 12124 at 3.

a. Line Transformer Costs Should Be Allocated On The Basis Of Non-Coincident Peaks.[17]

In its latest proposal, the Company allocates line transformer costs on the basis of number of customers in addition to load size, Gorman Rebuttal at 3, conceding that load size of individual customers is an appropriate and necessary basis upon which to allocate the cost of line transformers. The Company's modified allocation proposal for these costs continues to ignore the principles of cost causation.[18] E.g., Valley Gas, Docket No. 2276, Order No. 14834 at 27.

The Division's cost allocation and rate design expert, Dr. Dale E. Swan, demonstrated that the Company has not made any allowance for the different sizes of customers in terms of their loads. Swan Direct at 10-11; Swan Surrebuttal at 6-7. Thus, the Company treats a residential customer on Rate A-16 with a 3 kW load the same as a G-32 customer with a 200 kW

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[17] This Commission has rejected the use of a minimum system study to classify some portion of upstream plant as customer related, In Re: Narragansett Electric Co., Docket No. 1606/1692, Order No. 11227 at 7 (April 30, 1984), and should do so here for the reasons expressed in the Direct Testimony of Dr. Swan. Swan Direct at 9-10.

[18] The Division recommends allocating transformer costs and associated operating and maintenance expense on the basis of the average of the class responsibilities for non-coincident peak demand at primary and secondary voltages. Swan Surrebuttal at 7.

load or a G-62 customer with a minimum load of 3,000 kW. Swan Direct at 11. Even the Company concedes that there is no general rule regarding the number of customers that will be placed on a single transformer. Resp. to Division Data Request No. 18-5. In sum, Dr. Swan concluded, "there is no direct relationship between the number of customers and the costs of transformers or their maintenance." Swan Surrebuttal at 7. Any allocation based on customer numbers, therefore, will unfairly place these costs on customers who may not be responsible for them, thereby violating the principle of cost causation.

b. The Company's Delivery-related Uncollectibles Expense Should Be Allocated On The Basis Of Total Delivery Revenue.[19]

The Company contends that its uncollectibles expenses should be directly assigned to classes in which those costs originated, contending that the principle of cost causation requires the class that generated the expense should pay for the uncollectibles expense. Dr. Swan observed, however, that the *paying* customers that belong to any particular class *are simply not responsible* for the uncollectibles expense that the Company seeks to assign to them. That is, these customers do not cause the expense. Uncollectibles expense, therefore, "should be viewed as one of the general costs of doing business and should be allocated on the basis of some general allocator such as class revenues or energy."[20] Swan Surrebuttal at 8. Cost causation, then, does not provide a rationale supporting the direct assignment of the Company's delivery-related uncollectibles expense. Id.

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[19] Commodity-related uncollectibles expense should be allocated in a similar manner to the delivery-related portion of uncollectibles expense. Swan Direct at 35.

[20] As should the $1.0 million costs of the Economic Development Program should the Commission decide to approve these costs in the Company's revenue requirement.

c. *Customer Service And Information Expenses Should Be Allocated Based On Energy Use At The Meter.*

The Company proposes to allocate customer service and information expenses—approximately $5.4 million—largely on the number of customer bills. Gorman Rebuttal at 6. Again, the Company's allocation proposal is contrary to cost causation principles as it shifts costs to customer that are not responsible for those costs. See e.g., Providence Gas, Docket No. 1844, Order No. 12124 at 3 (cost allocation must be based on cost causation principles).

Dr. Swan demonstrated how the expenses that are booked in Account 908, 18 CFR Ch. I (4-1-04 Edition) are "directly related to class energy use and not the number of customers or bills." Swan Direct at 16. Account 908's description and the specific activities to be included in these accounts (*e.g.*, supervision, processing inquiries on proper use, advice on efficient and safe use of electric equipment) reflect energy use at the meter and is "consistent with the purpose for which these expenses have been made," namely the encouragement of "safe, efficient and economical use of the utility's service." NARUC Manual at 102; Swan Direct at 17-18. Thus, energy use at the meter represents a more appropriate method of allocating these costs among the various customer classes.

d. *Changes In Transmission Charges and SOS Administrative Charge Revenues Must Be Considered In Determining The Class Spread Of The Requested Revenue Increase.*

The Commission has identified "gradualism" as "an important policy consideration" when changing existing rates, particularly if the changes result in large increases. In Re: Tariff Filing by Narragansett Electric Co., Docket No. 1179, Order No. 11226 at 39 (August 1, 1983). The Company, however, has failed to account for other revenue changes—particularly transmission charges and for SOS administrative charge revenues—when "assessing the final spread of revenues among the classes." Swan Surrebuttal at 12.

The Company proposes to shift approximately $4.0 million in transmission revenue recovery from the Large C & I Demand class to the residential class, resulting in an "unusually large total increase" for the latter class. Swan Direct 25. Consistent with principles of gradualism, the Division mitigates this increase by reducing or increasing "each class" distribution revenue requirement by half of the resulting increase or decrease in transmission revenue shift. Swan Direct at 25, 28. The adjustment reduces residential distribution revenue increase from 17% to 12%, assuming a total revenue increase of $35 million. Swan Direct, DES-5 at 2.

2. Designing Rates

a. Mitigation Of Customer Charge Increase Impacts

The Company proposes to increase customer charges for A-16 customers by 100% and for C-06 customers by 67%. With respect to the Company's proposal, Dr. Swan, however, observed:

> [t]hese large increases in customer charges are out of line with the overall proposed increase that [is] in the 25% to 30% range, and they will have adverse impacts on the smallest customers in these two rate classes, who probably can least afford these increases during these troubled economic times.

Swan Direct at 31. Consistent with this Commission's recognition of the principle of gradualism, Narragansett Electric Co., Docket No. 1179, Order No. 11226 at 44, the Division recommends that the customer charge in Rate A-16 increase by no more than $1.00 and the charge in Rate C06 rate class increase by no more than $2.00, 36% and 33% increases, respectively. Swan Direct at 31.

b. Mitigation Of The Impact On The Company's Proposed C & I Large Demand Class

The Company proposes to eliminate the G-62 and B-62 rate schedules and move all customers with loads of 3,000 KW or higher into the G-32 and B-32 rate groups. Under the Company's proposal, delivery service charges for the very largest G-62 customers will increase from 14-18%, and will increase approximately 15-30% for B-62 customers. Swan Direct at 33. Although there is "a basis" for a "much higher increase for current G-62/B-62" as this class yields a "negative return of approximately -460 percent of the jurisdictional average," Swan Direct at 32, 34, the immediate imposition of such large increases is inconsistent with the principle of gradualism adopted by this Commission. Narragansett Electric Co., Docket No. 1179, Order No. 11226 at 44. The Division recommends, therefore, that the Commission retain the G-62/B-62 class, treating the State's largest customers as their own class, while phasing in the movement to rates "equivalent to those paid by G-32/B-32 customers" over a period of three to five years. Swan Direct at 34. During the transition period, any revenue shortfall should be allocated among the other classes with the exception of Lighting and Propulsion. Id. at 34-35. At the end of the transition period, the Division recommends that the Commission combine the two groups of C & I customers into one large C & I demand class as the Company has proposed. Id. at 35.[21]

IV. CONCLUSION

For the reasons expressed in this Brief as well as the Direct and Surebuttal Testimonies of the pertinent Division witnesses, the Division requests that the Commission provide the Company with a 47.50% equity capital structure, a return on equity of 10.1%, and an overall rate

[21] On January 15, 2010, the Division and TEC-RI reached a settlement in principle regarding certain aspects of the Company's proposed rate design. On January 19, 2010, the settling parties held discussions with Company representatives regarding the settlement in principle. If the Company accedes to the settlement, then the Division anticipates providing the Commission with further details of the parties' agreement in its Reply Brief due on January 29, 2010.

of return of 7.54%. The Division further requests that the Commission reduce the Company's base rate revenue requirement as filed by $37.872 million to $241.257 million including, but not limited to, reducing the Company's return on rate base and associated income taxes by $15.529 million, reducing the Company's operating and maintenance expenses by $18.653 million, and reducing the Company's delivery-related uncollectibles account expense by $2.933 million.

The Division's believes the Company's RDR Plan does not comport with the overwhelming national or local legal precedent. Nor does it comport with widely recognized ratemaking practice. For the reasons set forth in this Brief and in the Direct and Surrebuttal Testimony of the relevant Division witnesses, the Division requests that the Commission deny the Company's RDR Plan in its entirety including each of its various components, *i.e.*, Revenue Decoupling, the capital expenditures tracker, the I & M reconciliation mechanism, and the annual inflation adjustment on operating expenses. The Division recommends that the Commission allow recovery of commodity-related, uncollectibles account expense through the Company's SOS rates; however, the manner in which any such adjustment is calculated should be consistent with the Commission's treatment of bad debt in Docket No. 3943. Rates should be designed consistent with the Direct and Surrebuttal Testimony of Dr. Swan.

Respectfully submitted,

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CERTIFICATE OF SERVICE

I certify that a copy of the within Brief was e-mailed to the Service List in Docket No. 4065 on the 22nd day of January, 2010.