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November 15, 2013

Mark D. Marini, Secretary
Department of Public Utilities
One South Station, 2nd Floor
Boston, Massachusetts 02110

**Re: Bay State Gas Company d/b/a Columbia Gas of Massachusetts, D.P.U. 13-75**

Dear Secretary Marini:

Enclosed please find the **Public Version** of the Initial Brief of the Attorney General. The confidential version of the Attorney General's Brief will be filed separately to just the Department and the Company.

Thank you for your attention to this matter. Please do not hesitate to contact me if you have any questions about this filing.

Sincerely,

Assistant Attorney General

Enclosure
cc: Mark Tassone, Hearing Officer
Service List

**COMMONWEALTH OF MASSACHUSETTS**
**DEPARTMENT OF PUBLIC UTILITIES**

| | | |
|---|---|---|
| **Bay State Gas Company**<br>**d/b/a Columbia Gas of Massachusetts** | ) | **D.P.U. 13-75** |

**CERTIFICATE OF SERVICE**

I certify that I have this day served the foregoing documents upon each person designated on the official service list compiled by the Secretary in this proceeding. Dated at Boston this 15th day of November, 2013.

Joseph W. Rogers
Assistant Attorney General
Massachusetts Attorney General
Office of Ratepayer Advocacy
One Ashburton Place
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(617) 727-2200

cc: Service List

**COMMONWEALTH OF MASSACHUSETTS**
**DEPARTMENT OF PUBLIC UTILITIES**

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| **Bay State Gas Company, d/b/a Columbia Gas of Massachusetts** | ) ) ) ) | **D.P.U. 13-75** |

# INITIAL BRIEF OF THE ATTORNEY GENERAL


Respectfully submitted,
MARTHA COAKLEY
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November 15, 2013

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# INITIAL BRIEF OF THE ATTORNEY GENERAL

## I. INRODUCTION

On April 16, 2013, Bay State Gas Company, d/b/a Columbia Gas of Massachusetts ("Bay State" or "Company") filed a petition with the Department of Public Utilities ("Department"), pursuant to G.L. c. 164, § 94 and 220 C.M.R. § 5.00 et seq., for approval of a general increase in its gas distribution rates. The Company seeks to increase its annual revenues by $30.1 million, which it purports to be a 16.7 percent increase in base distribution revenues, or an increase of 7.5 percent in total annual operating revenues, including gas cost recovery. Pursuant to the briefing schedule established by the Department in this proceeding, the Attorney General's Office ("AGO") submits its Initial Brief.

## II. OVERVIEW

Like the Swallows of San Juan Capistrano, Bay State has made its annual return to the Department with yet another base rate filing.[1] As Bay State President, Stephen Byrant, testifies, "[t]his is the third rate case that the Company has filed in four years" (Exh. CMA/SHB-1, p. 5) and he promises to be back next year if the Company does not receive what it wants. Tr. Vol. I, pp. 10-11. Even if the Department gives the Company everything they want, including its

[1] Bay State's RFP for legal service for this rate case, D.P.U. 13-75, was sent out eight days after the Department's order in D.P.U. 12-25. *See* Exh. DPU-1-1 "The Legal RFP was issued on November 9, 2012."

Deferred in-Service Costs ("DISC") proposal, Mr. Bryant will not agree to a stay-out provision. Tr. Vol. I, pp. 14-15. Indeed, NiSource, Bay State's Indiana-based corporate parent, plans on filing annual rate increases in Massachusetts for the foreseeable future. Exh. AG-1-10.

Despite Mr. Bryant's histrionics, that the Department has somehow "wronged" the Company because "we are earning a lower return in Massachusetts than any other distribution company," (Tr. Vol. I, p. 17) the reality is that Bay State has received just and reasonable rates. The real problem is management.

Bay State management's decisions have unnecessarily increased costs to its gas distribution customers. First, it sold almost 20% of its pipeline business by divesting its Northern Utilities subsidiary. *Bay State Gas Company/UNITIL Corp.*, D.P.U. 08-43-A (2008). This divestiture increased costs by stranding more than $5 million in annual Company overhead costs that had been charged to Northern Utilities, but which are now being charged to Massachusetts operations. *Bay State Gas Company*, D.P.U. 09-30, p. 276 (2009). Second, in this case, the Company has demonstrated that the sale of its Energy Products and Services business, completed at the beginning of 2013, will increase overhead costs for Massachusetts gas distribution customers by another $5.7 million on an annual basis. Exh. CMA/JTG-2, Sch. JTG-4, Updated 9/3/13. Third, the Company has failed to grow its customer base, adding just 1.67 percent new customers during the test year compared to a 4.7 percent increase for other natural gas distribution companies like Boston Gas Company. Tr. Vol. I, p. 33. An increase in the number of customers would have added more income to the Company's bottom line, delaying the need to file for base rate increases. Tr. Vol. I, pp. 32-33. Fourth, NiSource Corporate Service Company's ("NCSC") charges to Bay State are out of control. Total charges from this affiliate to Bay State have increased by approximately $14.1 million, a whopping 48%, between

2008 and the 2012 test year - a rate more than ten times the rate of inflation in the last four years.[2] Exh. AG-DR-1, p.7. There is no evidence that Bay State management objected to these costs, since they, too, all work for the affiliate Service Company.[3] Tr. Vol. I, pp. 30-31. Finally, Bay State refused to take advantage of the ability to refinance its notes that are held by NiSource Corporate Finance, Inc., missing the opportunity to save over $5.1 million per year in interest payments. *Bay State Gas Company*, D.P.U. 12-25, pp. 389-390 (2012).

Despite its assertions of "inadequate earning," Bay State and its parent NiSource have no problem purchasing a second executive aircraft,[4] and having executive junkets at the Canyon Ranch in Lenox, MA.[5] Time and time again, costs paid by Bay State to affiliates increase without control, causing customers' rates to rise. If Bay State has "inadequate earnings," it is because its affiliates have sucked it dry. The Department should recognize what is occurring and protect customers. It is time to break the annual rate increase cycle.

## III. PROCEDURAL HISTORY

On April 16, 2013, Bay State filed the instant Petition. The Department docketed this proceeding as D.P.U. 13-75 and suspended the effective date of any rate increase until March 1, 2014 to investigate the propriety of Bay State's request. On April 22, 2013, the Department issued an Order of Notice and Notice of Filing, Public Hearing and Procedural Conference. The Department also included Public Hearings in: Lawrence on May 20; Brockton on May 21; and

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[2] The service company charges to Bay State increased by 8.14% during the test year alone.
[3] Twenty-Four of Twenty-Seven management employees at Bay State actually work for NiSource Corporate Service Company.
[4] Cessna Model 680 Sovereign. http://www.youtube.com/watch?v=QGjTrH1TJbo Despite Mr. Bryant's claim that "it's a more efficient way to move people than to use commercial airlines," (Tr. Vol. I., pp.41-42), the Company has failed to provide any support for Mr. Bryant's claims. The Company makes the same claims in Exh. AG-1-54, but fails to provide support that demonstrates the Bay State employees would have "to make multiple connections at greater cost and delay if they were required to take commercial flights."
[5] *See* Exh. AG-1-55, p. 1, line 13; see also http://www.canyonranch.com/lenox

Springfield on May 22; and Lawrence on May 24. Also on April 22, 2013, in a separate order, the Department suspended the effective date of any rate adjustment until March 1, 2014.

Pursuant to G.L. c. 12, § 11E (a), on April 18, 2013, the AGO filed a notice of its statutory right to intervene. Also on April 18, 2012, pursuant to G.L. c. 12, § 11E(b), the AGO determined that it was necessary and appropriate to retain one or more experts or consultants to assist in this proceeding and filed with the Department a Notice of Retention of Experts And Consultants in this matter ("AGO's Notice"). Neither the Company nor any other party filed comments on the AGO's Notice, which was allowed by the Department on May 17, 2013.

The Massachusetts Department of Energy Resources ("DOER"), the New England Gas Worker's Association (NEGWA)[6] and Conservation Law Foundation ("CLF") filed for full intervention status. The following additional parties also filed Petitions for Limited Participant status: Berkshire Gas Company, Boston Gas Company and Colonial Gas Company d/b/a National Grid, and New England Gas Company. At the May 16, 2013 Procedural Conference, the Department granted the full and limited intervention status to those parties that filed motions.

Over the course of the proceeding, the AGO, the Department and other parties issued a number of information requests. The Department conducted thirteen days of evidentiary hearings between October 1 and October 25, 2013. During the evidentiary hearings, Bay State presented nine witnesses: Stephen H. Bryant, David E. Mueller, Richard Fontaine, Jeffery T. Gore, Vincent V. Rea, Kimberly K. Cartella, Brian E. Elliott, Joseph A. Ferro, Susan Taylor, and Mark P. Balmert. The AGO presented six witnesses: David E. Dismukes, Ph.D., J. Randall Woolridge, Ph.D.; Rebecca Bachelder; David Effron, Allen Neale, and Donna Ramas.

[6] On May 15, 2013, NEGWA withdrew its petition.

## IV. DESCRIPTION OF THE COMPANY

Bay State Gas Company, d/b/a Columbia Gas of Massachusetts, is a wholly-owned subsidiary of NiSource, Inc. ("NiSource"). Bay State is a natural gas distribution company that provides retail service to approximately 295,000 residential, commercial and industrial customers in three divisions throughout seventy-two Massachusetts cities and towns. The Company's operations are divided into three non-contiguous geographic divisions identified by their major cities (i.e., Springfield, Lawrence and Brockton).

Bay State's parent corporation, NiSource was created in 1998 with the merger of Bay State Gas Company and Northern Indiana Public Service Company ("NIPSCO"). Shortly thereafter, in 2000, NiSource merged with Columbia Energy Group ("Columbia"), which was the owner and operator of two major interstate natural gas pipelines and five natural gas local distribution companies in Maryland, Virginia, Kentucky, Ohio and Pennsylvania. Through its combined operations, NiSource serves more than 3.3 million customers in seven states and operates approximately 57,000 miles of distribution pipeline.

NiSource, headquartered in Merrillville, Indiana, is a registered public utility holding company subject to the jurisdiction of the Securities and Exchange Commission ("SEC").

## V. STANDARD OF REVIEW

The Department must review the "propriety" of general rate increases under G. L. c. 164, § 94 ("Section 94"). In reviewing the "propriety" of a proposal by a utility under Section 94, the Department must determine whether the proposed rates are just and reasonable. *Attorney General v. Department of Telecommunications and Energy*, 438 Mass 256, 264 n. 13 (2002); *Berkshire Gas Company*, D.P.U. 96-67, p. 6 (1996). An application of a generic public interest test derived from organic authority must give way to the specific statutory just and reasonable analysis required when examining a request for a general increase in rates. *Attorney General v. Department of Telecommunications and Energy*, 438 Mass at 270; *see also Cambridge Electric Light Company v. Department of Public Utilities*, 333 Mass. 536 (1956).

The party seeking the rate increase bears the burden of proof. *Town of Hingham v. Department of Telecommunications and Energy*, 433 Mass. 198, 213-14 ( 2001), citing *Metropolitan District Commission v. Department of Public Utilities*, 352 Mass. 18, 24 (1967); *Wannacomet Water Co. v. Department of Public Utilities*, 346 Mass. 453, 463 (1963). Included in that burden is a responsibility to develop a record sufficiently complete to support a Department order in its favor on any contested issue. *Fitchburg Gas and Electric Light Company*, D.T.E. 99-118, p. 7, n.5 (2001) (the Company bears the burden of proving each and every element of its case by a preponderance of "such evidence as a reasonable mind might accept as adequate to support a conclusion."); G. L. c. 30A, § 11(6); P. LIACOS, HANDBOOK OF MASSACHUSETTS EVIDENCE, § 14.2 (7th ed. 1999). In Section 94 proceedings, the intervenors have neither the burden of production nor the burden of proof. D.T.E. 99-118, p. 7 (2001). To prevail, however, intervenors must produce evidence necessary to rebut a Company's allegations. D.T.E. 99-118, p. 9.[7] G.L. c. 30A, §§ 10, 11.

The Department must evaluate all evidence, including rebuttal evidence and negative evidence, and make findings that result in just and reasonable rates.[8] The Department, however, cannot validly do so without furnishing detailed and subsidiary findings of fact and conclusions

[7] "[T]he burden of proof is the duty imposed upon a proponent of a fact whose case requires proof of that fact to persuade the factfinder that the fact exists or, where a demonstration of non-existence is required, to persuade the factfinder of the non-existence of that fact."); *Fitchburg Gas and Electric Light Company*, D.T.E. 99-118, p. 7, (2001.)

[8] The Department must weigh all of the evidence, not just the evidence that supports the conclusion reached, but also contrary evidence that derogates from that conclusion." *Town of Hingham v. Department of Telecommunications and Energy*, 433 Mass. 198, 215 (2001).

of law sufficient to demonstrate that the overall rate determination is just and reasonable.[9] "G.L. c. 30A, s 11(8), requires the decision of the department to 'be accompanied by a statement of reasons ... including determination of each issue of fact or law necessary to the decision.'" *Massachusetts Institute of Technology v. Department of Public Utilities*, 425 Mass 856, 867 (1997). *NSTAR Electric Company v. Department of Public Utilities* 462 Mass. 381, 387 (2012).

A rate is not just and reasonable simply because a utility says so. If the Company fails to carry its burden by a preponderance of the evidence, the Department must deny the Companies' requested rate treatment for the proposed adjustment. *Fitchburg Gas & Electric Light Company v. Department of Public Utilities*, 375 Mass. 571, 582-583 (1978). The Department should be guided by its duty to protect public interests and not promote private interests. *Mass.-American Water Company,* D.P.U. 95-118, p. 77 (1996). *Fitchburg Gas and Electric Light Company*, D.P.U. 09-09 pp. 22-23, citing *Commonwealth Electric Company v. Department of Public Utilities*, 397 Mass. 361, 369 (1986); *Attorney General v. Department of Pub. Utilities*, 390 Mass. 208, 235 (1983); *Lowell Gas Light Co. v. Department of Pub. Utilities*, 319 Mass. 46, 52 (1946).

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[9] "[W]e have insisted that the agency make subsidiary findings of fact on all issues relevant and material to the ultimate issue to be decided, and that it 'set forth the manner in which it reasoned from the subsidiary facts so found to the ultimate decision reached'." *Massachusetts Institute of Technology v. Department of Public Utilities*, 425 Mass 856, 871 (1997) *citing School Comm. of Chicopee v. Massachusetts Commission Against Discrimination*, 361 Mass. 352, 354-355 (1972).

## VI. ARGUMENT

### A. The Department Should Eliminate Many of Bay State's Automatic Adjustment Mechanisms

Bay State's various adjustment mechanisms allow it to recover its actual costs from customers for a specified function on a periodical basis outside of a rate case. One of the major purposes of these adjustment mechanisms is to reduce the frequency of rate cases.[10] However, Bay State's recent history of rate case filings and its expected automatic future rate case filings vitiate this important benefit.

Bay State has filed a rate case in three out of the last four years. Evidence provided in this case demonstrates that the Company intends to file annual rate cases until at least 2018. Exh. AG-1-10 (A) Confidential, p. 52 of 109; Exh. AG-1-10 (B) Confidential, p. 52 of 109; Exh. AG-1-10 (C) Confidential, p. 52 of 109. These annual rate case filings in addition to annual adjustment mechanism filings create an undue administrative burden for the Department and AGO, and also increase rate case and investigative expenses that are reflected in customer rates. Constantly preparing and supporting rate cases through litigation drains management resources from the Company that would be better spent improving the efficiency of its operations, rather than constantly seeking higher rates from customers. If Bay State does not agree to a hiatus in rate case filings for three to five years (the typical rate case filing schedule of most other Massachusetts utilities), then the Department should eliminate the following adjustment mechanisms: Pension & PBOP Expense Factor; TIRF; and Revenue Decoupling Adjustment Factor. Pro forma test year adjustments can be easily made in the Company's annual rate case filings without the need to administratively burden the Department with separate reconciling mechanism proceedings. The prudence of the existing historical costs recovered through each

[10] Adjustment mechanisms are a "useful as a way to avoid repetitive and costly general rate proceedings." *NSTAR Gas & Electric*, D.T.E. 03-47-A, p. 17, fn. 17 citing *Worcester Gas Light Company*, D.P.U. 11209 (1955).

reconciliation mechanism can be determined in one final rate case proceeding by the Department to close out the adjustment clauses to be eliminated.

This is an appropriate response to a Company that indicates that it will file a new base rate case next year if it does not receive exactly what it wants in this case. *See* Tr. Vol. I, pp. 10-11. While the Department arguably may not deny the Company the right to file for a new general rate increase pursuant to G.L. c. 164, § 94, it can certainly use its inherent power over rate mechanisms in response to the to eliminate its other repetitive and time consuming filings that are no longer needed, in light of the Company's annual rate case filings.

### B. The Department Should Reject the Company's Updates

This rate case proceeding has been filed pursuant to the recent amendments to G.L. c. 164, § 94, which authorize the Department to suspend the effective date of the rates for ten months, while it undertakes an investigation. In response to the General Court's modification of § 94, Mr. Bryant demands that an "accommodation" be made for Bay State. Exh. CMA/SHB-1, p. 40. He claims that the ten-month suspension period "will impair a utility's ability to obtain rates that reflect current costs and this will simply promote the need for more rate cases."[11] *Id*.

The procedural schedule allowed the Company to proffer an updated cost of service on June 30, 2013, for O&M and capital expenditures related to the NIFIT program, and other non-revenue capital additions through April 30, 2013; and on September 3, 2013, a final update was filed of O&M and capital expenditures related to NIFIT project through August 31, 2013; and other non-revenue capital additions through June 30, 2013.[12] Although the procedural schedule

[11] As indicated above, the record in this case establishes that Bay State already has an annual filing plan through 2018, notwithstanding any legislative or Department changes to the ratemaking process.

[12] The June 30 update included updated testimony of Richard Fontaine, David E. Mueller and Jeffery T. Gore along with updated schedules. The September 3 update included the testimony of Bruce M. Sedlock regarding the recent Massachusetts Franchise Tax rate change and the testimony of Jeffery T. Gore regarding the update to the revenue requirement calculation with known changes since the June 30, 2013 Update filing.

allowed for the updates, the Department's procedural order indicated that the "inclusion of this [June 30, 2013] update step and the similar step on September 3, 2013, does not constitute a ruling on the propriety of allowing the updated information in the record." H.O. Procedural Order, p. 2 (May 17, 2013).

The Department must reject the Company's June 30 and September 3 updates as improper.[13] The General Court has spoken clearly that a full ten-month time frame is needed to conduct an adequate investigation of Bay State's rate filing. *See Saccone v. State Ethics Commission*, 395 Mass. 326, 335 (1985); *Telles v. Commissioner of Insurance*, 410 Mass. 560, 564-565 (1991) (an administrative agency has no authority to promulgate rules and regulations which are in conflict with the statutes or exceed the authority conferred by the statutes). The Department may not circumvent that ten-month period to review the proposed rate, granted both to the Department and to intervenors, by permitting the Company to amend its petition on a schedule of its own choosing and thereby defeating the ten-month review period.[14]

Mr. Bryant's attack on the General Court's act is based on the assumption that rates set on the basis of a historical test year will prove deficient with a Company that is involved in a post-test year construction program, like its Targeted Infrastructure Replacement Program.[15] In theory, everything else being equal, if rate base grows disproportionately to revenues after the test year, a Company may fail to earn its authorized return. While this may be an "algebraic

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[13] *See* NiSource Corporate Services section below for a description of the moving target many of the updates created.

[14] As of November 13, 2013, Bay State is still updating schedules and exhibits based on errors the Department Staff identified. See Bay State November 13, 2013 filing ("corrected" versions of Exh. DEM- 6 and Exh. DEM-8, along with the relevant project documentation). The continued need to "update" in order to correct errors, long after the hearings have closed and the parities can verify the accuracy of the documents, are an indicia of the lack of reliability of Bay State's entire filing. Rather than present a fully prepared and documented rate filing, Bay State is involved in a hasty money grab rather than a legitimate rate increase. So much for the Company's representation for a quick turnaround. Tr. Vol. 5, pp. 522-523.

[15] Actually, Bay State has one of the most favorable regulatory environments when compared to other NiSource affiliates. Tr. Vol. I, pp. 37-38; citing Company's Response to AG-1-10-A p. 67.

truism," in the "real world" "everything is never equal." *Eastern Edison Company*, D.P.U. 1580, p. 20 (1984). The Company's revenues and expenses inevitably change. With efficient and economical management, a utility can actually profit from these changes. Why else has NSTAR Gas not filed a fully litigated rate case since 1991 (D.P.U. 91-60),[16] nor Berkshire Gas Company since the end of its Performance Based rate plan. It is not uncommon for companies to over-earn its authorized return. *Fitchburg Gas and Electric Light Company*, D.T.E. 99-118 (1999).

By corollary, in restoring Section 94 to its pre-1975 text, the General Court also re-introduced an important consumer protection to reduce waste and inefficiency – "Regulatory Lag" – "the time gap between when a utility undergoes a change in cost or sales levels and when the utility can reflect these changes in new rates." K. Costello, "How Should Regulators View Cost Trackers?" National Regulatory Research Institute (Sept. 2009), p. 4.

The General Court's action is consistent with good economic theory, which "predicts that the longer the regulatory lag, the more incentive a utility has to control its costs; when a utility incurs costs, the longer it has to wait to recover those costs, the lower its earnings are in the interim." *Id*. "Regulatory lag can be a useful ratemaking tool to deter utility waste and cost inefficiency." *Bay State Gas Company*, D.P.U. 12-25, p. 22 (2012). "The utility, consequently, would have an incentive to exercise efficient management and minimize additional costs." *Id*. In addition, an efficiently managed utility has an "incentive between rate cases to improve its earnings through cost reductions or increased demand" because it can keep those earnings. *NYNEX*, D.P.U. 94-50, p. 110, n. 71 (1995).

[16] In fact, NSTAR agreed as part of its most recent merger settlement to maintain its current base distribution rates until January 1, 2016, during which period it would actually have the opportunity to retain the benefits of any cost reductions that it may realize as a result of its merger.

The Department should reject Bay State's attempt to circumvent the amendments to Section 94. The Department relies on historical test year data, adjusted for known and measurable changes when setting base rates.[17] The Department has determined that,

> the use of a calendar test year is the most efficient means to conduct such an investigation. When considering a s. 94 rate case, the Department examines a test year, which usually represents the most recent twelve-month period for which complete financial information exists, on the theory that the revenue, expense, and rate base figures during that period accurately reflect the utility's present financial situation and fairly predict the company's future performance. To the extent that known or anticipated changes in revenues, expenses, or rate base will distort the correlation among these elements, adjustments are made in the test year data to reflect those changes. *Boston Edison Company v. Department of Public Utilities*, 375 Mass. 1, 24, 375 N.E.2d 305 (1978) cert. denied 439 U.S. 921 (1978).
>
> In addition, the Company already files its costs and revenues on a calendar-year basis in its annual report to the Department.

*Fitchburg Gas and Electric Light Company*, D.T.E. 99-118, Interlocutory Order Regarding Scope of Proceeding and Motion to Compel Discovery, p. 8 (2001).

### C. Distribution System Integrity Management Program and Capital Plans

In 2009 the Pipeline and Hazardous Materials Safety Administration ("PHMSA") established requirements for a program of integrity management for gas distribution pipeline systems, more commonly known as the Distribution Integrity Management Program ("DIMP"). 49 C.F.R. § 192.1000 *et seq*; Exh. AG 12-8, p. 3 of 112. The Federal Pipeline Integrity, Protection, Enforcement, and Safety Act of 2006 directed PHMSA to create minimum standards for integrity management programs for gas distribution companies. Pub. L. 109-468 (2006). Rather than imposing a one-size-fits-all specification for integrity management, PHMSA

[17] See Rate Base section below regarding how the Company's proposal is a move towards a future test year. Section VI.F, *infra*.

concluded that a requirement for operator-specific programs to manage pipeline system integrity would be more effective given the diversity in distribution systems and the threats facing them. 74 Fed. Reg. 63906 (2009).[18] The integrity management program can be thought of as a self-examination process that may or may not result in the Company changing any operating, maintenance or investment behavior. According to federal regulations, PHMSA requires system operators to have:

- Developed and demonstrated an understanding of the company's system.
- Identified and considered threats to each gas distribution facility.
- Completed a risk evaluation and ranking of their distribution system.
- Developed criteria for deciding when risks require measures to reduce them.
- Determined the measures to reduce risk.
- Begun implementing the measures to reduce risk or have a plan to implement measures to reduce risk which includes an implementation schedule.
- Assessed the effectiveness of their leak management program and taken steps, if necessary, to correct deficiencies.
- Established a baseline measurement for each performance measure required by 49 C.F.R. §§192.1007(e)(1)(i)-(v).
- Developed performance measures to evaluate the effectiveness of measures to reduce risk, have a plan to collect the performance measure data, and begun collecting data to establish a baseline measurement.
- Determined the appropriate period for conducting DIMP program evaluations.
- Reported performance measures required by 49 C.F.R. §192.1007(g) for calendar year 2010.
- Collected data as needed for mechanical fitting failures resulting in hazardous leaks beginning January 1, 2011.

[18] Further information concerning the scope of the DIMP program is available on the PHMSA website. http://primis.phmsa.dot.gov/dimp/

- Identified records requiring retention and have maintained them.

49 C.F.R. § 192.1007.

The PHMSA regulations guiding the program created a comprehensive framework and iterative process to assist with integrity management that should be nuanced and tailored to a company's system. It did not require any specific changes to operations, maintenance, or investments. Companies were required to study their own systems to gain operational awareness and consider areas for potential improvements. Gas distribution system operators were given until August 2, 2011, to write and implement a program. 49 C.F.R. § 192.1005. Bay State completed its DIMP on the last day for compliance, August 2, 2011, and updated the program documentation on January 1, 2012, and January 25, 2013. Exh. AG 12-8, p. 122 of 112. The version of the plan in the record appears to be the most recent update. *Id*. Although the Company has updated a limited number of sections of its plan in 2013, the data analysis in the numerous charts and metrics ends in 2011.[19]

According to the Company's filing "[a]dministration of DIMP requires a ramp-up in capital replacement for leak-prone mains and services," Ex. CMA/DEM-1, p. 23, however, there is plainly no requirement in the PHMSA regulations mandating any particular level of capital investment under the DIMP or changes to long term capital plans, as the Company pretends. Moreover, any accelerated capital expenditures based on integrity concerns should be supported with analysis within the DIMP; but here the Company admitted during hearings that it had no quantifiable analysis for its decision to set the pace of replacement for a quarter of its system to the 20 year mark, Bay State's current target. Tr. Vol. II, p. 274-275. No cost benefit analysis of any sort was identified to support this long term capital plan. Why not 15 years for 10% of the

[19] Other than Table A-3 and Table A-11, which references updates in 2012, the remainder of the DIMP data does not appear to have changed since 2011 figures. Exh. AG 12-8, pp. 79, 88 of 112.

system or 25 years for 75% of the system? The Company does not say, and that silence is telling.

Although the Company pointed to specific sections of the DIMP during cross examination to support its decision to accelerate replacements under its capital plans, the referenced part of the DIMP simply memorialized the decision that the Company already made. Tr. Vol. II, p. 2667-267, *citing* Exh. AG 12-8, p. 104 of 122. What is more, the data examined in the Company's DIMP primarily ends in 2011, yet the Company is relying on it to convince the Department to approve investment decisions for 2012 and capital planning into the future. The distribution system is dynamic, changing with patterns of investment and maintenance, and if the Company intends to rely on the DIMP to justify ramped-up capital spending, it must provide the Department with an updated DIMP that at least includes data for the 2012 test year used in this case.

There is no connection between the levels of acceleration of bare steel and cast iron replacement spending and the specific goals that the Company intends to meet with this capital plan. The Company actually describes the analytical process that went into the determining the ramped-up pace as "fluid" and "that could increase or could decrease; it just depends on a lot of factors." Tr. Vol. II, pp. 274-275. This response is another way of saying that the Company, more-or-less, pulled the pace of replacement out of thin air, but it is the main cost driver for accelerated replacements under the TIRF.

This approach should be troubling to the Department, and such a leap is completely at odds with the underlying philosophy of the DIMP. DIMP was designed for a utility to examine its own system and make nuanced decisions based on the existing state of its facilities. PHMSA did not impose a one-size-fits-all regime of solutions by simply accelerating the removal of bare steel and cast iron because "less is better," but that is essentially what the Company is doing with its capital plan under the auspices of the DIMP.  According to the Averch-Johnson Effect[20] utilities will have incentives to select sub-optimal capital investments over O&M solutions because the utility can earn a return on the capital investment but not on the O&M expense, so the Department should closely scrutinize substantial investment programs, like accelerated replacement, that have significant gaps in analytical justification.  To the extent that the Company can demonstrated that the process of examining its system through a federally mandated program indeed revealed material shortcomings in its existing integrity management requiring ramped-up investment, it has produced a document that conclusively proves its own imprudent management of the safety of its distribution system and placed the public at risk.  It would be difficult for the Company to argue that it had no pre-existing duty to evaluate the safety of its system prior to the promulgation of 49 C.F.R. § 192.1000 *et seq*., and take appropriate remedial action based on the results of that review.

By failing to link the proposed level of accelerated spending on cast iron and bare steel replacement in its long term capital plan with any sort of analysis of the DIMP itself, the Company proposes spending significant dollars for ramped-up replacements with special cost recovery from customers, but with potentially uncertain results.  Such a proposal is unlikely to result in a least cost solution for integrity management.  The Department must reject this ad hoc type of management for investments of this magnitude that have such clear safety consequences for the public.  The AGO fully supports least cost solutions to a safe and reliable gas distribution system so that customers are assured of reasonably priced gas delivery services in keeping with the Company's public service obligations.  The Company filing did not satisfy these

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[20] Averch, Harvey & Johnson, Leland L., "*Behavior of the Firm Under Regulatory Constraint*", American Economic Review (1962).

requirements in this case. Although the Department would be justified in these circumstances to deny recovery of ramped-up replacement costs for these reasons, the AGO recommends that the Department require the Company to file a cost benefit analysis with its next TIRF filing, or request for approval of a capital plan[21] that links the desired system safety benefits with a range of least cost alternative solutions for accomplishing those goals.

## D. Distribution System Delivery Capacity

### 1. NETWORK ANALYSIS AND SYSTEM MODERNIZATION

The Company must prove that the pipes, like other capital investment, it seeks to include in rate base are prudent as well as used and useful in the service of customers. *Fitchburg Gas and Electric Light Company*, D.P.U. 07-71, p. 27 (2008); *Town of Hingham v. Department of Telecommunications and Energy*, 433 Mass. 198, 202 (2001). In this case it has not adequately provided an analysis of system capacity associated with system capital additions to sustain this burden. As explained by the AGO's witness Allen Neale, Network Analysis is a useful tool for examining the effects on the distribution system's ability to deliver gas when system components are replaced or expanded. Exh. ARN-1, p. 9. Infrastructure "replacement" is a far more complex undertaking than simply putting the same size main in the ground as was taken out. Exh. ARN-3, pp. 17-31; Exh. AG 21-10(a). With the aid of Network Analysis, when the Company planners decide to remove a main, the pipe segment may be replaced with the same diameter main, a smaller diameter main, or be eliminated altogether. Exh. ARN-3, p. 20. The size of the main along with the system pressure, a factor affected by regulator stations that reduce gas pressure coming off the citygate and throughout different operating pressure regions, (*Id.*, pp. 23-24), determine how much gas can be delivered to any section of the Company's

[21] If House Bill No. 2950 becomes law, then the current TIRF mechanism may be abandoned for more favorable treatment under the new law, but Bay State must first file a capital plan for approval with the Department.

system.  *Id*., pp. 21-22.  And, the Company is in the process of moving its system from a low to a high pressure system, which will greatly increase overall system capacity to deliver gas.  *Id*., pp. 21-22.  All of these factors must take into consideration how much supply customers may actually need throughout the operating areas, and these factors change.

It is reasonable to see that as a planner reviews Network Analysis over time, the planner would be able to observe the effect that load growth, or the loss of customers, has on the system. Exh. ARN-1, p. 9.  As new load is added to the distribution system, it follows that gas pressures would drop.  When those pressure drops become too severe the remedy is larger pipe, pressure regulation, or other engineering solutions.  Exh. ARN-3, pp. 17-31.  Network Analysis tools allow a system planner to optimize the length and diameter of the pipe that needs to be installed to remedy any design-day low pressure issues.  *Id*.  Just as gas supplies are requisitioned to meet the design day distribution system needs, the system itself must be designed to deliver those supplies to the customer.  Bay State agrees with these basic gas engineering principles:

> All of our systems are designed for a peak-day design condition, I believe in our case it is minus 20 degrees Fahrenheit. So essentially the model takes a look at current demand and correlates it to the historical weather conditions experienced at that time. It then uses various statistical processes to extrapolate what the demand on our system would be under those conditions. And then that's what's used for our final design.

*Id*., p. 21.  Based on this testimony, the Company designs its system "for a peak-day design condition" and uses the SynerGEE software system to model each of its three service areas.  Exh. AG 21-10 (f) – (m).  SynerGEE computerizes a range of distribution system modeling and engineering functions that determine the impacts on system capacity to deliver gas from replacement, expansion, and reliability projects.  *Id*.

As the record amply demonstrates, without the technical assistance of Network Analysis it would not be possible for the Company to perform distribution system capital activities with any degree of understanding about the how much gas the system would be able to deliver after the project is complete. That would jeopardize reliability. The deliverability of gas to customers lies at the heart of the public service obligation of any local gas distribution company, including Bay State. The Network Analysis would help demonstrate what portion of a pipe is useful for delivery of gas, and what part may be excess capacity.

#### *a) Failure to Provide Technical Analysis*

The Company did not produce the Network Analysis associated with the investments in pipe that it seeks to include in rate base. The Company claims that it does not save the software configurations, so the SynerGEE runs to support individual pipe investments decisions are unavailable. Exh. AG 21-12; ARN-1, p. 10. This is true despite the fact that the Company stated under oath that the "[a]dministration of DIMP requires a ramp-up in capital replacement for leak-prone mains and services," Exh. CMA/DEM-1, p. 23, and federal law requires that DIMP compliance documentation be retained for ten years. 49 C.F.R. § 192.1011. The Company did not provide a substitute analysis, so the Department has no substantial evidence in the record upon which to conclude the degree to which the proposed pipe additions to rate base identified in Exh. AG 21-8 and Exh. AG 21-9 are prudent, used, and useful in the service to customers. How did system and sub-system and deliverable volumes change over time with each segment addition? Neither the Department nor AGO can tell based on this record; yet this inquiry is a critical part of examining the prudence of the added capacity.

Under Department precedent, the failure to provide adequate reviewable documentation will result in exclusion from rate base. *Boston Gas Company*, D.T.E. 03-40, p. 52 (2003). The Department does not permit one side in a litigated dispute to rely on the results of technical analysis, while simultaneously depriving the other side of the opportunity to examine that same technical information. *Verizon*, D.T.E. 01-20, pp. 16-19 (2001). However, that is precisely what has occurred in this case. Exh. AG 21-12. "For costs to be included in rate base, expenditures must be prudently incurred, and the resulting plant must be used and useful to customers." *Town of Hingham v. Department of Telecommunications and Energy*, 433 Mass. 198, 202 (2001). The Department's standard for prudence reviews is well known:

> A prudence review must be based on how a reasonable company would have responded to the particular circumstances and whether the company's actions were in fact prudent in light of all circumstances which were known or reasonably should have been known at the time a decision was made.

*Boston Edison Company*, D.P.U. 906, p. 165 (1982). Without the same Network Analysis to review, neither the Department nor the AGO can assess the resulting system capacity from the proposed additions to rate base. The Department cannot assume precise technical quantified data, like the amount of deliverability across the Company's system. *Boston Gas Company v. Department of Public Utilities*, 436 Mass. 233, 240-242 (2002) (accumulated inefficiencies value requires direct quantitative evidence). The record lacks substantial evidence to support a conclusion that the Company's main investments are prudent, and so the Department must exclude the capital additions listed in Exh. AG 21-8 and Exh. 21-9 from rate base. Even if the Company could demonstrate the prudence of these investments – which it cannot on this record – the lack of contemporaneous Network Analysis also deprives the Department the ability to determine the extent to which the investments are used and useful. As explained below, the record in this case fully supports the AGO's concerns about the amount of system capacity the Company seeks to include in rate base through operation of the TIRF or under the modernization plan.

### *b) Peak Day Exceeds Design Day in Springfield*

The AGO's gas engineering expert witness, Allen Neale, noted in prefiled testimony that the Company could be generating excess system capacity under its approach to pipe investments. Ex. ARN-1, pp. 6-7. This observation was well founded, as litigation of the case eventually revealed. In response to a record request for the Company to "please identify how much gas, in dekatherms, can be delivered to customers on a design day versus peak day, by service area," the Company revealed that in 2013 its Springfield Service Area experienced a Peak Day sendout that eclipsed its Design Day sendout:

| Springfield | | |
|---|---|---|
| Peak Day | | Fcst Design Day |
| Dth | Date | Dth |
| 161,387 | 1/24/2013 | 160,781 |

RR-AG-3. Peak Day should not exceed Design Day, as even the Company agrees:

> Delivery of reliable gas service is necessary to meet the Company's regulatory and public safety obligations. Failure to maintain the gas distribution system in a manner capable of delivering usable gas supply to individual customers will likely result in outages usually during the coldest time of the year when customers need and expect reliable gas service the most. Both intermittent gas service and the loss of gas service pose a threat to health, safety and property.

Exh. A 21-10(a). The Company has also stated unequivocally that its "systems are designed for a peak-day design condition." Ex. ARN-3, p. 21. Yet, unless the Company failed to deliver gas in Springfield on January 24, 2013, this system condition indicates that Bay State has more capacity than necessary to meet its forecasted customers' needs in the Springfield operating division. This system anomaly should be a red flag for the Department to examine further the actual system capacity the Company is building under modernization, and should not be lightly brushed aside for at least two reasons.

(1) The Company Targets Excess Capacity

First, when pressed on the excess capacity issue during hearings, the Company finally testified that it engineers the distribution system for a 3% increase in capacity during the "redesign and replace" efforts:

> And so basically what we're looking for, what we're assuming is basically a 3 percent load growth distributed throughout the existing system.

Tr. Vol. II, p. 254-255. As for the amount of capacity being added under the modernization program, the Company testified that that it does not differentiate capacity targets by program:

> The infrastructure replacement program really accounts for everything that we're looking to do, whether they are or they aren't included in TIRF. . . . It's all aggregated together.

Tr. Vol. II, p. 257. When questioned about how the Company derived the assumed 3% capacity growth metric, the Company referred to its forecast and supply plan as the source. Tr. Vol. II, p. 254-255. But in response to RR AG-4, the Company revealed that the most recent five-year forecast and supply filed in D.P.U. 13-161 projects only a 1.2% increase. That case is pending with the Department, and the Company did not provide the growth rate from the currently approved forecast and supply plan in D.P.U. 11-89 (2012), which is undoubtedly lower than 1.2%. The Company uses a target capacity increase far in excess of anticipated needs in its most recent forecast, a filing that should reflect the most current market conditions and prices.

In the record request response, the Company attempts to qualify the use of the 3% assumed capacity increase to only "replacement" areas with reliability issues, RR AG-4, but this statement is contradicted by repeated answers elsewhere during live testimony regarding the use of the 3% load growth figure across the system generally and on an "aggregated" basis for all categories of projects under the modernization plan. Tr. Vol. II, pp. 254-257. The Department should give less weight to attempts in a record request response to contradict live testimony considering that the witness is no longer on the stand and subject to follow-up examination. In any event, the after-the-fact elaboration contains no analysis whatsoever supporting the 3% load growth assumption either system-wide or in more limited regions, nor does it affirmatively state that the Company actually uses the 1.2% forecasted growth figure for system engineering purposes. The Company suggests that the 3% figure used in areas of the system where the Company anticipates growth over the five-year horizon, RR-AG-4, but for that to be true, the Company must have performed another forecast or reliability study for the qualifications in AG RR-4 to be anything more than a guess of future system needs. Customers should not be forced to pay for guesses. No such five year "plus" forecast was identified or provided for localized 3% growth rates, while the record request indeed asked for the source of the 3% figured.

While the Company fails to supply any analytical support at all demonstrating why building its system to 250% over projected future capacity needs is prudent, the Company stated in response to questions about its system requirements that:

> The Company builds, maintains and expands its distribution system to reliably meet firm end-user demand, particularly ensuring that distribution capacity is adequate to serve its firm customers on design day. In conjunction with on-system distribution capacity, the Company contracts for upstream pipeline deliverability or capacity to its various city-gates and maintains on-system plant vaporization capacity to secure deliverability of supply to satisfy, essentially closely matching, firm end-user demand on design day.

Exh. AG 27-1. This response, of course, largely misses the mark, because it addresses the availability of physical gas supply and not the upper limit of deliverability of that supply across its distribution system.

(2) Intergenerational Equity

Second, the Company has provided no basis to support such an intergenerational subsidy from existing customers to hoped-for future ones, nor directly addressed the issue. How much more system capacity the Company targets and constructs is the relevant issue. As noted by Mr. Neale:

> [I]t's foolhardy to take a 30-year view of looking at the needs of your system, because that load may not materialize, and you would have overbuilt your system, and you would ask the current customers to pay for that.

Tr. Vol. XII, p. 1238. Today's customers should not be forced to pay for an open-ended amount of excess capacity in the hopes that new customers will eventually materialize to soak up demand. That is why rate base is limited to used and useful investments, prudently incurred. *Fitchburg Gas and Electric Light Company*, D.T.E. 98-51, p. 9 (1999), *citing Boston Gas Company*, D.P.U. 96-50 (Phase I) at 15 ("For ratemaking purposes, the Department determines rate base according to the cost of the utility's plant in service as of the end of the test year under a used and useful standard;" therefore, the excess capacity is neither used nor useful to future ratepayers.). In order to qualify for inclusion in rates, a utility's plant investment must be in service and providing benefits to then-existing customers. *Id*. *See also Hingham v. Department of Telecommunications and Energy*, 433 Mass. at 203 ("a public utility's rate base is its total prudent investment in property that is "used and useful" to the public in providing utility service during the test year."). Further, the program cannot provide net economic benefits to ratepayers. *Western Massachusetts Electric Company*, D.P.U. 85-270, pp. 60-107 (1986).

While there may be some degree of capacity held for near term system expansion, Tr. Vol. XII, p.1237-1238, the TIRF program as currently administered, as well as the proposed rate base additions for pipes, allocates 100% of the costs of the excess distribution system capacity to present customers regardless of the net benefits to customers of the individual plant additions. *Id*. As admitted by the Company, new business capacity expansion projects are different than replacement projects and are subject to an internal rate of return analysis. Tr. Vol. II, p. 255. That analysis was apparently not performed with the ongoing 3% rule of thumb uprating, and the Department has not approved expansion cost recovery by stealth under the TIRF. *Fitchburg Gas and Electric Light Company*, D.T.E. 98-51, p. 9 (1999), *citing Boston Gas Company*, D.P.U. 96-50 (Phase I) at 15.

Furthermore, the proposed current long term forecast estimates only a 1.2% increase, while the Company uses a figure that is 250 % of this amount without analysis to support such a huge increase over what is already being forecast as needed. Shareholders are allocated no cost, and can earn a return almost immediately, whether the plant ever provides fully useful service to new or existing customers. This apportionment is without question unjust and would not be affirmed by the courts. *Town of Hingham v. Department of Telecommunications and Energy*, 433 Mass. at 202. ("For costs to be included in rate base, expenditures must be prudently incurred, and the resulting plant must be used and useful to customers.") The "used and useful" standard generally requires that a utility plant must be in commercial operation and providing net benefits to [current] customers in order for expenses associated with it to be included in rate base."). Therefore, allocating 100% of the future costs of extra capacity to present customers fails to satisfy the "used and useful" standard because the future extra capacity is not in service at the end of the test year and fails to provide net economic benefits to ratepayers. *Western Massachusetts Electric Company*, D.P.U. 85-270, pp. 60-107 (1986).

With current customers picking up 100% of excess system capacity costs, the Company will have zero investment risk for unused capacity and no incentive to restrain its investment decisions, none of which will result in a least cost pipe replacement program or expansion planning. The Company has accomplished this thoroughly lopsided allocation of costs and benefits silently, and without directly vetting this issue with Department through prefiled testimony or study. The results of such an analysis cannot be assumed. *Boston Gas Company v. Department of Public Utilities*, 436 Mass. at 240-242. *See also Massachusetts Institute of Technology v. Department of Public Utilities*, 425 Mass. 856, 870 ("In fact, the department's initial order concedes that it lacked information on which to base its decision, stating 'there is little information regarding the efficiency improvements that should result as regulated companies move from [COS] to [PBR].' While we recognize that some uncertainties cannot be precisely quantified, we do require more than a conclusory statement to that effect."). The record lacks any evidence either to allocate 100% of excess system capacity cost to today's customers or conversely to determine what amount of excess system capacity may be reasonably built in anticipation of load growth or system expansion. The Department must exclude excess capacity from rate base either through a subsequent investigation to examine the amount of excess capacity that should be deducted from rate base or as a new variable added to the TIRF mechanism to reduced excess capacity from rate base in annual filings.

## E. Modifications to the Targeted Infrastructure Recovery Factor

### 1. INTRODUCTION

While it is the AGO's position that Bay State's Targeted Infrastructure Recovery Factor ("TIRF") should be eliminated due to the expected future annual rate case filings, it is necessary to discuss the significant modifications that Bay State has requested in this docket to change the TIRF from what was approved by the Department in D.P.U. 09-30, and D.P.U. 12-25. Specifically, Bay State requests the Department approve modifications of the TIRF to (1) significantly change the existing one percent rate impact cap, (2) allow a “waiver” provision if Bay State decides for itself that the Department’s threshold replacement level of 38 miles of main per year is not attainable, and (3) include carrying costs couched as Deferred In-Service Costs (“DISC”) as TIRF-eligible. All of the proposed modifications have the potential to seriously erode key ratepayer protections associated with the TIRF. Furthermore, the prohibition of carrying costs in investment tracker mechanisms is well established Department policy, and inclusion of such costs is counter to one of the primary, if not the primary, rationale for the Department’s approval of the TIRF in D.P.U. 09-30, p. 130.

The time is also ripe for the Department to take a measured review of its current enforcement mechanism adopted in D.P.U. 12-25. The AGO recommended in the last Bay State rate case that the Department adopt strict leak-rate based performance targets for Bay State to meet. Since the TIRF inception, Bay State’s leak inventory has increased considerably compared to pre-TIRF levels, creating harmful economic, safety, reliability, and potentially even GHG emissions and other environmental effects for ratepayers. Setting strict leak-rate based performance targets with corresponding adjustments to Bay State’s TIRF-related return on equity would tie the TIRF to achieving meaningful public benefits from reduced natural gas leaks, while eliminating existing concerns of program continuity.

### 2. OVERVIEW

The Department has a long history concerning proposals made by Bay State to establish infrastructure cost recovery riders. As early as 2004 in D.T.E. 05-27, Bay State proposed the recovery of costs associated with its Steel Infrastructure Replacement (“SIR”) program through a base rate adjustment mechanism, a proposal which Bay State revisited again two years later as part of D.P.U. 07-89. In both proceedings, the Department rejected the Company’s proposed infrastructure cost recovery rider as being unnecessary since the Company's proposed rate of replacement was consistent with historic replacement rates, and thus could not be defined as accelerated. *Bay State Gas Company*, D.T.E. 05-27, pp. 46-49 (2005); *Bay State Gas Company*, D.P.U. 07-89, pp. 43-44 (2008). The Department also noted that the proposal's annual infrastructure recovery mechanisms were inconsistent with and would undermine the efficiency incentives that were part of Bay State's then-active performance-based regulation ("PBR") price cap formula. *Bay State Gas Company*, D.T.E. 05-27, p. 48 and n. 44.

Bay State requested yet another infrastructure cost recovery mechanism, termed the Targeted Infrastructure Reinvestment Factor ("TIRF"), which was ultimately approved by the Department in D.P.U. 09-30. The Department's approval was based upon what it saw as "three significant differences" from the Company's prior SIR proposals. *Bay State Gas Company*, D.P.U. 09-30, pp. 130-131 (2009). First, the TIRF was based upon actual incremental replacement investments, and not representative replacement investments as was proposed in prior cases. *Id*. Second, the TIRF excluded carrying charges. *Id*. Third, the TIRF included a one-percent rate impact cap, a protection missing from prior Bay State proposals. *Id*. The Department found "these structural differences in the [TIRF] recovery mechanism constitute a substantive change" relative to the Company's previous proposals. *Id*. The Department also formally terminated the Company's PBR plan, removing an important Department reservation in reviewing prior infrastructure cost recovery proposals. *Id*.

However, in each of its last two rate case filings, Bay State's replacement investment recovery proposals have violated the conditions and protections established by the Department in D.P.U. 09-30 when approving the original TIRF. Having been granted the proverbial "inch," Bay State has continually sought the proverbial "mile." First, in D.P.U. 12-25, Bay State requested that the Department abandon the TIRF in favor of a Rate Year/Rate Base ("RY/RB") proposal that amounted to a fully forecasted test year incorporating 80 percent of Bay State's anticipated (not actual) capital budget. The Department had repeatedly noted in D.P.U. 09-30 that its approval of the TIRF was based upon the confidence that the TIRF was limited and targeted in nature, *Bay State Gas Company*, D.P.U. 09-30, pp. 133-134 (2009), yet in D.P.U. 12-25, Bay State proposed a TIRF mechanism which was anything but targeted, expanding the definition of eligible investments to include all infrastructure investment associated with non-revenue generating steel and cast iron service lines and mains 12 inches and less in diameter. *Bay State Gas Company*, D.P.U. 12-25, pp. 26-27. Now, in the current proceeding, Bay State seeks to undermine many of the key ratepayer protection mechanisms included in the original TIRF approved in D.P.U. 09-30.

In D.P.U. 12-25, the Department rejected Bay State's RY/RB proposal, on the grounds that (1) the mechanism was akin to the institution of a future test year, (2) it dramatically expanded the scope of the TIRF, (3) it undermined positive elements of regulatory lag, and (4) Bay State failed to adequately establish that its operating costs are efficient. D.P.U. 12-25, pp. 19-24. The Department further noted that the existing TIRF had failed to deliver an accelerated level of non-cathodically protected steel main replacements. *Bay State Gas Company*, D.P.U. 12-25, p. 47 (2012). However, the Department found that the public benefits of accelerated replacement of leak-prone infrastructure had not changed, *Id*., and approved a more modest request by Bay State to expand the existing TIRF to include small-diameter (i.e. twelve inches or less) cast-iron and wrought-iron mains, but establishing a "threshold level" of main replacement of 38 miles per year, while declining to adopt a leak-rate proposal as requested by the AGO. D.P.U. 12-25, pp. 49-54.

Bay State now seeks to weaken TIRF ratepayer protections through three modifications under the premise that declining gas prices have jeopardized its ability to replace the Department's 38 mile threshold level under the mechanism, and that certain costs incurred between the in-service date of a TIRF project and the date on which TIRF recovery commences for a project causes the Company to file frequent rate cases. Exh. CMA/SHB-1, pp. 8-9. First, Bay State proposes to modify the rate impact cap of the TIRF from 1.0 percent of total revenue to 3.75 percent of base revenues. Exh. CMA/SHB-1, pp. 32-33. Second, Bay State proposes to allow the company the ability to file for a waiver under circumstances where it cannot meet the Department's 38 mile threshold. Exh. CMA/SHB-1, pp. 34-35. Lastly, Bay State requests the recovery of DISC, allowing rate recovery of financing costs incurred from the point that a project goes into service to the point that rate recovery commences through the TIRF. Exh. CMA/SHB-1, p. 36.

As justification for the need for the proposed DISC in the TIRF mechanism (and to a lesser extent the other two proposed modifications), Bay State presents a catalog of presumed failures in the Department's current regulatory structure hindering, if not outright preventing, the Company's ability to earn its authorized rate of return. Tr. Vol. I, p. 100. This argument is not supported by the record evidence. The Department already provides a full suite of generous cost recovery mechanisms, when compared to fellow NiSource subsidiaries. Tr. Vol. I, p. 37-41; *see also* Exh. AG-1-10-A. Moreover, as Dr. Dismukes' operating cost analysis shows, the Company's operating cost efficiencies are worse than like-situated utilities, suggesting the Company has not exhausted potential efficiency gains. Exh. AG/DED-1, pp. 81-86.

Furthermore, in approving the TIRF in D.P.U. 09-30, the Department conditioned its decision on the belief that that "more aggressive replacement of bare steel is appropriate and desirable from a public policy perspective given the potential benefits to public safety, service reliability, and the environment." *Bay State Gas Company*, D.P.U. 09-30, p. 133 (2009). However, Bay State has clearly failed to reduce active leaks on its system through the accelerated replacement of leak-prone facilities through the TIRF. From 2008, the year immediately prior to the adoption of the TIRF, to the 2012 test year, active leaks on Bay State system have increased approximately five fold. Exh. AG/DED-1, Schedule DED-18. Likewise, the cost effectiveness of Bay State's replacement efforts have significantly worsened through the course of the TIRF, with replacement costs per mile of replaced main more than tripling since 2008, or increasing by an entire factor of eight since 2007. Exh. AG/DED-1, Schedules DED-10 and DED-11.

Bay State's historically poor TIRF performance record, coupled with its current request to jettison Department policy from D.P.U. 09-30, more than justifies rejecting the Company's proposed modifications to the TIRF. In fact, the Department should move one step further and establish a new enforcement mechanism that scales Bay State's TIRF-related return on equity directly to the Company's achievement of leak-based performance standards. This new enforcement mechanism will ensure that the TIRF mechanism provides its originally anticipated public benefits that in large part have failed to materialize.

The AGO recommends that if the Department allows continuation of any TIRF mechanism, it should replace its current enforcement mechanism adopted in D.P.U. 12-25 with a strict leak-rate based performance target of a five percent per year reduction in corrosion-related leaks from mains and seven percent per year reduction in corrosion-related leaks from services. Exh. AG/DED-1, p. 71. Allowed rates of return should be adjusted to increase or decrease as leak performance improves or worsens, such that if the Company misses its leak reduction target by one percent, its allowed return on equity under the TIRF would also be reduced by one percent. The AGO further recommends that a 25-basis point cap be placed on increases or decreases to allowed return on equity from these performance adjustments. Exh. AG/DED-1, p. 72. In making this recommendation, the AGO notes that the leak reduction targets are based on the five-year average leak reduction rates experience by Bay State prior to the adoption of the TIRF. *Bay State Gas Company*, D.P.U. 12-25, p. 34 (2012); citing AGO Brief p. 37 and Exh. AG/DED-1, pp. 3-4. These proposed performance benchmarks are not designed in any way to be punitive to the Company, but rather are designed to return infrastructure replacement performance to rates seen prior to the adoption of the TIRF.

### 3. THE DEPARTMENT SHOULD REJECT BAY STATE'S PROPOSED MODIFICATIONS TO THE TIRF

Bay State's proposal consists of three modifications to the TIRF. First, Bay State proposes to change the existing one percent rate impact cap set by total revenues, to one calculated as 3.75 percent of base distribution revenues. Second, Bay State proposes to allow itself to utilize a waiver process that would allow Department approval of an annual work plan under the Department's threshold replacement level of 38 miles of main per year. Finally, Bay State requests approval of carrying costs associated with TIRF investments in the form of DISC.

#### *a) Existing Rate Impact Cap Is Sufficient to Meet the Upper Bound of the Company's Current Investment Targets.*

Bay State claims that while the current one percent rate impact cap was sufficient at the time of Department approval in D.P.U. 09-30 to allow predictable operations, two changes made to the TIRF in D.P.U. 12-25 and the decline of gas revenues in the marketplace have rendered the cap as insufficient to cover basic program costs required of the TIRF. Exh. CMA/SHB-1, pp.

32-33. However, the record shows that Bay State has failed to convincingly demonstrate this purported necessity.

As shown by Dr. Dismukes, the Company has historically invested far less in pipeline replacement than allowed under the existing one percent rate impact cap. Exh. AG/DED-1, pp.19-20; and Exh. AG/DED-1, Schedule DED-3. In fact, Dr. Dismukes found that Bay State had only averaged annual investments equal to 56.9 percent of that allowable under the existing rate impact cap. *Id*. Dr. Dismukes further demonstrated that going forward, the current rate impact cap is not likely to be an investment constraint to the Company for two reasons. First, Bay State base distribution revenues have been growing at an average annual rate of over four percent for the past three years, with shares of total revenue increasing from 21 percent of the Company's total revenues to over 45 percent, during the same time-frame. Exh. AG/DED-1, p. 20; and Exh. AG/DED-1, Sch. DED-4. Second, independent analysis from the Energy Information Administration ("EIA") projects natural gas commodity prices to increase by an inflation-adjusted annual average of nearly two percent through 2028, which should cause comparable increases in commodity revenues for the Company. Exh. AG/DED-1, p. 21. Dr. Dismukes estimates that there will be considerable headroom over the next eight years between anticipated TIRF investments, and the maximum allowable investments under the existing one percent rate impact cap. Exh. AG/DED-1, p. 23; and Exhibit AG/DED-1, Schedule DED-8.

**#BEGIN CONFIDENTIAL#**[redacted]

[redacted] **#END CONFIDENTIAL#** The Department should reject the Company's request to modify the TIRF rate impact cap as without a clear demonstrated foundation of need.

#### ***b) The Company Has a Cost Containment Problem, Not a Revenue Problem.***

The record shows that Bay State's complaint that slow revenue growth is inhibiting the Company's ability to make infrastructure investments under the current TIRF one percent rate impact cap ignores the impact of Bay State's failure to control its pipeline replacement unit costs, which have had a large, if not larger, impact on its ability to operate under the rate impact cap than slow revenue growth. Specifically, the Company's replacement costs per mile of replaced main and replaced service have increased 216 and 145 percent, respectively, over the past ten years. Exh. AG/DED-1, p. 24; and Exh. AG/DED-1, Schedule DED-10. Revenues during the same period have declined by only 20 percent. *Id*.

Bay State's inability to control pipeline replacement unit costs is even more striking when examined since the approval of the TIRF. Since 2008, the year immediately prior to the approval of the TIRF, total costs of replaced mains per mile of main has more than tripled. *Id*. In D.P.U. 09-30, the Company provided data showing that projected replacement costs of mains and services would be barely more than $269,000 per mile of main replaced. Exh. AG/DED-1, p. 25; and Exh. AG/DED-1, Schedule DED-11. However, to date, unit costs have exceeded this estimate by a baffling 356 percent, having averaged nearly $950,000 per mile of main replaced. *Id*. Further, Bay State had the highest pipeline replacement unit costs of all Massachusetts natural gas utilities granted infrastructure tracker mechanisms in 2012, Exh. AG/DED-1, p. 25; and Exh. AG/DED-1, Schedule DED-12, and one of the highest rates of unit cost growth. Exh. AG/DED-1, pp. 25-26; and Exh. AG/DED-1, Schedule DED-12.

The Department should put Bay State on notice that it will not weaken key ratepayer protection due to the inability of the Company to prudently manage its costs of operations. This is consistent with the Department's clear cost containment sensitivities expressed in D.P.U. 12-25:

> In addition to the above findings, we also stress, as we did in D.P.U. 09-30, that the TIRF is not intended to permit the Company to invest capital dollars irresponsibly. The importance of this fact is heightened by the establishment of the threshold level of main recovery. Bay State retains the flexibility and discretion to make main replacement decisions, so long as the Company meets the threshold level of miles of leak-prone pipe replaced. However, <u>we expect that the Company will manage its replacement activities in an efficient and effective fashion</u> in order to meet the annual main replacement threshold. *Bay State Gas Company, D.P.U. 12-25,* p. 55 (2012), internal citations removed and emphasis added.

***c) The Company's Claims That the Need for Change Arises from the Department's Decision in D.P.U. 12-25 Ignores the Facts in the Record.***

Bay State's claim that the need to change the existing rate impact cap arises even partially from the Department's decision in D.P.U. 12-25 to include small diameter cast iron mains and services and adopt a threshold level of annual installations of 38 miles of mains and associated services is unbelievable and ignores the record evidence in both D.P.U. 09-30 and D.P.U. 12-25. To the extent that the existing one percent rate impact is insufficient to allow the Company to engage in accelerated replacement efforts under the TIRF, an argument the AGO contests, it is a problem solely of the Company's own making, and not the Department's.

Prior to its TIRF proposal in D.P.U. 09-30, Bay State had sought a similar base rate adjustment mechanism to recovery costs associated with its SIR. The Company made this proposal first in D.T.E. 05-27, and then two years later revisited the proposal as part of D.P.U. 07-89. In both proceedings, the Department rejected the Company's proposed infrastructure cost recovery rider for a number of reasons, including because the mechanism was deemed unnecessary since the Company's proposed rate of replacement was consistent with historic replacement rates, and thus could not be defined as accelerated. *Bay State Gas Company*, D.T.E. 05-27, pp. 46-49 (2005); *Bay State Gas Company*, D.P.U. 07-89, pp. 43-44 (2008). In proposing the TIRF in D.P.U. 09-30, Bay State explicitly included ratepayer protection mechanisms including a rate impact cap based on one percent of total revenues from the prior calendar year. Exh. AG/DED-1, pp. 43-44. The moderation of Bay State's infrastructure recovery proposals worked, and the Department in D.P.U. 09-30 approved the TIRF based upon what it saw as "three significant differences" from the Company's prior SIR proposals, including notably the included one percent rate impact cap. *Bay State Gas Company*, D.P.U. 09-30, pp. 130-131 (2009).

In D.P.U. 12-25, the Bay State proposed two modifications to the TIRF if the Department rejected its proposed RY/RB methodology. One of these modifications was to include small diameter cast-iron and wrought iron mains within the tracker. D.P.U. 12-25, p. 26. In proposing this addition, the Company noted that cast-iron and wrought-iron pipes less than 12 inches in diameter "have a relatively low beam strength and as such are more susceptible to cracks and breaks." *Id*. The Department approved Bay State's requested modification, noting a Pipeline Hazardous Materials Safety Administration ("PHMSA") advisory to operators to accelerate the repair, rehabilitation, and replacement of aging high-risk cast-iron pipe in the wake of a deadly cast-iron explosion in Pennsylvania. D.P.U. 12-25, p. 49.

Notably, both the original one percent rate impact cap in D.P.U. 09-30 and the expansion of the TIRF to include small diameter cast-iron and wrought-iron mains in D.P.U. 12-25 were proposals of Bay State, and not any other party to the proceedings, nor the Department. Indeed, the Company requested cost recovery of all cast iron mains less than 12 inches in diameter, a threshold greater than that approved for other gas utilities in the Commonwealth. D.P.U. 12-25, p. 49. Furthermore, nowhere in D.P.U. 09-30 was Bay State prohibited from proposing to modify the existing rate impact cap. One of the few references to the rate impact cap in D.P.U. 12-25 explicitly stated that "the Company is not proposing to change the one percent cap for the Modified TIRF, with the inclusion of cast-iron infrastructure." Exh. AG/DED-1, p. 26. If either the inclusion of small diameter cast-iron and wrought-iron mains or post-2009 natural gas prices is the reason for the need to modify the TIRF rate impact cap, D.P.U. 12-25 would have been an appropriate venue to address these issues. In D.P.U. 12-25 the Department was adequately positioned to both weigh the benefits of accelerated replacement of cast-iron and wrought-iron mains with the reduced ratepayer protections needed to allow the Company appropriate flexibility, and examine the effect of falling natural gas prices on the Company's ability to make adequate accelerated infrastructure investments, as that case was argued a full four years after natural gas commodity prices had fallen from their all-time highs. Exh. AG/DED-1, p. 27.

Bay State's argument that the Department's "mandate" of the 38 mile annual replacement rate is justification for any need to modify the existing TIRF rate impact cap is similarly disingenuous. The Department imposed no such mandate, but rather set a threshold replacement target level of 38 miles given Bay State's "poor" pipeline replacement performance in the three years following its TIRF adoption. D.P.U. 12-25, p. 53. The Department determined 38 miles as an appropriate threshold as this was the average annual replacement rate for the years 2007 through 2011, with Bay State notably operating outside of the TIRF for the years 2007 through 2009. D.P.U. 12-25, p. 54. Furthermore, the evidence in the record shows that 38 miles is far below the 53 to 70 mile annual replacement the Company would need to replace its entire leak-prone infrastructure in the Company's time-frame of 15 to 20 years. Tr. Vol. I, pp. 105-107. The Department should reject the proposed modification of the TIRF rate impact cap as a "bait-and-switch" ploy. The raison d'être for the TIRF was to encourage utilities to replace the so-called leak-prone infrastructure within a time-frame necessary for the safe operation of their distribution systems. The Department should reject the proposed modification of the rate impact cap as contrary to the core design of the TIRF.

#### 4. THE COMPANY'S PROPOSAL UNDERMINES AN IMPORTANT RATEPAYER PROTECTION ASPECT OF THE TIRF.

In both D.T.E. 05-27 and D.P.U. 07-89, the Department rejected requests by Bay State to implement a SIR charge. In proposing the current TIRF mechanism in D.P.U. 09-30, the Company included the current one percent rate impact cap as a means to limit the rate impacts of the mechanisms on Bay State customers, while preserving the discretion of the Company's management by deferring investments in excess of the cap to future recovery periods. Exh. AG/DED-1, pp. 43-44. The proposed rate impact cap was one of three items the Department identified as "structural differences" from the prior rejected SIR proposal. *Bay State Gas Company*, D.P.U. 09-30, p. 130 (2009).

The Company now attempts to weaken this vital ratepayer protection mechanism critical to the approval of the original TIRF in D.P.U. 09-30 by both increasing the monetary value of the cap, *see* Exh. DPU-6-1; *see also* Exh. AG/DED-1, Schedule DED-9, and furthermore replacing the emphasis on total revenues with only distribution revenues. As noted by the Mr. Bryant during the hearing, when examining mitigation of rates from year to year, it is more important to ratepayers that total bills are not exorbitantly increasing than it is that the distribution portion of a ratepayer's bill is contained. Tr. Vol. I, p. 96.

#### *a) Waiver Request*

Bay State requests that the Department accept a proposed modification of its existing TIRF to include a waiver provision, providing the Company with the opportunity to seek the Department's approval of annual work plans in circumstances where the Company believes it should focus on goals other than linear feet of main. Exh. CMA/SHB-1, p. 31. The Company notes that it "accepts" the Department's 38 mile threshold requirement and "anticipates" exceeding the requirement in order to meet the goals of it system modernization plan. Exh. CMA/SHB-1, p. 34. However, Bay State believes there could be circumstances in the future where work may be reasonably and prudently devoted to specific larger-scale projects that preclude the Company from meeting the Department's threshold. *Id*. The Company does not define any limitations on the duration for these requested waivers, and goes so far as to note that such requests could be for "one or more construction seasons." Exh. AG/DED-1, p. 47; citing Exhibit CMA/DEM-1, p. 32.

##### (1) The Company Misinterprets the Department's Order in D.P.U. 12-25.

In requesting the inclusion of a waiver provision within the Company's TIRF, Bay State states that the Department's order in D.P.U. 12-25 "mandated" that the Company replace of 38 miles of priority mains per year or risk losing the TIRF. Exh. CMA/SHB-1, p. 32. This is an obvious misinterpretation of the Department's order. The Department's imposition of a 38 mile threshold level of replacement activity was a "performance metric," and not a "mandate" as stated by Bay State. D.P.U. 12-25, pp. 51 and 54. The Department adopted this standard given the Company's "poor" pipeline replacement performance in the three years following its TIRF adoption. D.P.U. 12-25, pp. 47 and 54-55. The Department even frustratingly noted in D.P.U. 12-25 that "the Company's pre-TIRF levels of main replacement exceeded the annual replacement levels that were experienced after the TIRF was approved." D.P.U. 12-25, p. 54.

In developing the 38 mile threshold level, the Department consulted historical Bay State pipeline replacement activities, specifically the average annual replacement rate for the years 2007 through 2011. D.P.U. 12-25, p. 54. Notably, Bay State operated outside of the TIRF for the years 2007 through 2009, or half of the selected time frame. In this manner, the performance standard adopted by the Department was clearly set to be consistent with historic trends and designed in a fashion to incent the Company to replace pipes at a rate consistent with minimum expectations, as well as the Company's assertions, at the time of the TIRF's approval. D.P.U. 12-25, pp. 53-54. Bay State, in proposing to allow a waiver provision to the TIRF, fails to appreciate or even acknowledge that its poor performance in prior years necessitated the Department's 38 mile threshold as a "safeguard" to ensure that public benefits of the program are realized. D.P.U. 12-25, pp. 47-48.

Furthermore, the Company's belief that it may have difficulties in the future meeting the Department's 38 mile replacement threshold ignores Bay State's own time schedule for replacement activities. Mr. Stephen Bryant, president of Bay State, stated before the Department that it was "looking at orders of magnitude somewhere in the fifteen to twenty-year range" for replacement of all of the Company's leak-prone infrastructure. Tr. Vol. I, p. 105; *see also* Exh. CMA/SHB-1, p.5. With the utility having 1,082 miles of such infrastructure on its system at the end of 2012,[22] Bay State must average approximately 54 to 72 miles of replacement per year to

[22] The Company possessed 1,103 miles of leak-prone pipeline at the end of 2011, and replaced 21 miles in 2012. *See*, D.P.U. 12-25, Exhibit CMA/DAR-1, p. 43. Exhibit AG/DED-1, Schedule DED-11.

meet its internal deadline of replacing its entire leak-prone infrastructure in 15 to 20 years. *See* Tr. Vol. I, pp. 105-106. This is a full 42 to 89 percent greater than the Department's threshold adopted in D.P.U. 12-25.

(2) The Company's Waiver Request Is Tantamount To A Pre-Determination Of Prudence.

The Company's waiver request carries the additional uncertainty of Bay State arguing in the next prudence review that the Department's granting of the waivers should be deemed as the equivalent to a pre-determination of prudence. Exh. AG/DED-1, p. 53. Thus, if the Department approves such future waiver requests, the Department should specifically indicate that this does not impact and future prudence recourse, as well as the prudence recourse of other parties.

### 5. DEFERRED IN-SERVICE COSTS

Bay State proposes to radically expand its existing set of TIRF-eligible costs to include those incurred from the point that a project goes into service to the point that rate recovery commences in the tracker. Exh CMA/SHB-1, p. 36. The costs proposed by Bay State include financing costs, depreciation expenses, and taxes, collectively referred to as DISC. Exh. CMA/JTG-1, p. 63 and; Exh. CMA/SHB-1, p. 36. Under Bay State's proposal, financing costs would be based on the Company's long-term debt costs and be booked as a deferral until its next rate case. Exh. CMA/JTG-1, p. 64. The Company positions its proposal under the guise that the existing ratemaking process does not account for DISC costs, and that accounting for DISC is necessary to bring rates into alignment with costs. Exh. CMA/SHB-1, pp. 36-37.

### *a) The Company's Proposal Is Contrary to one of the Key Department Rationales for Approving the TIRF in D.P.U. 09-30.*

Bay State's DISC request pretends that the Company has not previously applied for carrying charges associated with infrastructure replacement trackers. This is simply untrue. Prior to the Department's approval of the TIRF in D.P.U. 09-30, Bay State twice proposed a SIR mechanism which included a carrying cost component. *Bay State Gas Company*, D.T.E. 05-27, (2005); *Bay State Gas Company*, D.P.U. 07-89, (2008). In both proceedings, the Department rejected the Company's proposed infrastructure cost recovery rider for a number of reasons, including that the mechanism was deemed unnecessary since the Company's proposed rate of replacement was consistent with historic replacement rates, and thus could not be defined as accelerated. *Bay State Gas Company*, D.T.E. 05-27, pp. 46-49; *Bay State Gas Company*, D.P.U. 07-89, pp. 43-44 (2008). As a means of presenting the TIRF as more palatable than the prior SIR proposals, Bay State dropped the carrying costs component from its TIRF proposal, and touted that it had done so by specifically noting that, "[t]his [removal of carrying costs] represents a substantial modification to earlier proposals and imposes 100% of the financing cost burden during this interval (10 to 22 months) on Bay State." Exh AG/DED-1, p. 55.

In approving the TIRF, the Department rejected an argument by the AGO and the United Steelworkers of America that the proposal was essentially no different than the prior SIR mechanisms rejected by the Department in D.T.E. 05-27 and D.P.U. 07-89. *Bay State Gas Company*, D.P.U. 09-30, pp. 129-130 (2009). The Department noted that the TIRF possessed three "significant differences" with prior SIR proposals, one of which was the omission of a carrying cost component. *Bay State Gas Company*, D.P.U. 09-30, p. 130 (2009). Bay State's current reversal for all intents and purposes of this important ratepayer protection should be rejected by the Department. DISC, as well as the other proposed TIRF modifications, represents a transparent attempt to achieve a "bait-and-switch" on the part of Bay State to attain what the Department previously rejected.

#### ***b) The Company's Proposal Ignores Clear Department Precedent Of Not Allowing Carrying Costs Associated with Infrastructure Trackers.***

Bay State's DISC proposal pretends that this is not an issue that the Department has previously considered, and rejected. The Department very clearly articulated in D.P.U. 10-55 its policy reasons for excluding carrying costs from infrastructure replacement trackers. Specifically, the Department noted the clear detrimental effect such inclusion would have on the positive effects from regulatory lag. *Boston Gas Company*, D.P.U. 10-55, pp. 134-135 (2010).

> National Grid [Boston Gas] argues that a billing delay carrying charge is needed because the acceleration of replacement activities for leak-prone facilities will require substantially more capital on a year-to-year basis than National Grid has required in the past. However, the Department has previously expressed concerns about utility companies' acceleration of capital expenditures supported by a special ratemaking mechanism that would allow immediate cost recovery because it reduces and potentially eliminates the important incentive that regulatory lag provides to companies to maintain an appropriate balance between investing in capital improvements and incurring O&M expenses.

*Boston Gas Company,* D.P.U. 10-55, pp. 134-135 (2009); *citing Bay State Gas Company,* D.P.U. 09-39, p. 81 (2009).

Further, it should be noted that in rejecting the proposal of Boston Gas Company to include carrying charges as an element of annual TIRF revenue requirement, the Department referenced its finding in D.P.U. 09-30 approving Bay State's TIRF as precedent for its rejection of carrying charges. *Boston Gas Company*, D.P.U. 10-55, p. 135 (2010). The Department should reject Bay State's DISC request for the same reasons.

### *c) Addition DISC Accounting Issues*

There are other technical problems with the Company's proposed DISC mechanism that will cause it to overstate the Company's costs. These include determining the actual in service date of any plant additions, the use of long-term debt as a carrying charge, and the assumption that the Company pays property taxes on plant investment from the date that the plant goes into service. Each of these will be discussed below.

First, the Company's proposal to start charging costs on the date that the plant goes into service will mean that the Company and the Department will have to attempt to verify and track each vintage of plant, by the date it actually went into service, so that the calculation of any associated carrying costs might be correctly calculated. Exh. CMA/SHB-1, p. 36. Dating plant in service dates for each plant addition is essentially impossible for the Department to review and approve; it would require the Department to take evidence, review each individual addition, and issue a finding of fact on each addition. Moreover, the Company will have every incentive under this regime to improperly account for investment as "in service" at the earliest date, even though it might not actually be in service, in order to start accruing carrying charges at the earliest possible date.

Second, the Company is proposing to use the cost of long-term debt as the carrying cost rate when that is not the Company's actual cost rate. *Id*. The only carrying cost rate that the Department can recognize is the Company's short-term debt interest rate. Until the Company receives approval from the Department to issue any new securities after meeting the net plant test, the only assumption can be that the Company is financing plant investments with short-term debt.[23] G.L. c. 164, § 14, Indeed, short-term debt is the first source of funds that both the Department and the Federal Energy Regulatory Commission assume is used to fund construction.[24] Therefore, the Department must reject the Company's proposed use of long-term debt as the carrying charge in any proposed DISC mechanism.

Third, the Company proposes to include property taxes in the DISC mechanism, even though it will not have to pay those taxes for as much as a year and a half after the plant goes into service. Exh. CMA/SHB-1, p. 36. Municipalities value the Company's property to assess property taxes once a year, on January 1. Tr. Vol. I, p. 688. The tax invoices for that January 1 valuation are then sent out for payment after July 1 of that year. *Id*. Thus, plant investment put into service in mid-January of 2012, the test year in this case, would not start to accrue property taxes until the mid-point of 2013, almost a year and a half later. *Id*., pp. 688-689. Even plant investment put into service as of the end of the test year does not start to accrue property taxes for six months after it's in service date. Therefore, the Department must reject the Company's proposal to include property taxes in the determination of any DISC mechanism.

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[23] Before approving the issuance of stock, bonds, coupon notes, or other types of long-term indebtedness by an electric or gas company, the Department must determine that the proposed issuance meets two tests. G.L. c. 164, § 14.

(1) First, the Department must assess whether the proposed issuance is "reasonably necessary for the accomplishment of some purpose having to do with the obligations of the company to the public and its ability to carry out those obligations with the greatest possible efficiency." *Fitchburg Gas & Electric Light Company v. Department of Public Utilities*, 395 Mass. 836, 842 (1985) ("Fitchburg II"), citing *Fitchburg Gas & Electric Company v. Department of Public Utilities,* 394 Mass. 671, 678 (1985) ("Fitchburg I") and *Lowell Gas Light Co. v. Department of Public Utilities,* 319 Mass. 46, 52 (1946).

(2) Second, the Department must determine whether the Company has met the Department's "net plant test" derived from G.L. c. 164, §16. To satisfy the net plant test, a company must present evidence showing that its net utility plant (original cost of capitalizable plant less accumulated depreciation) equals or exceeds its total capitalization (the sum of its long-term debt and its preferred and common stock outstanding, exclusive of retained earnings) and will continue to do so following the proposed issuance. *Colonial Gas Company,* D.P.U. 84-96, at 5 (1984).

[24] 18 C.F.R. 201 Gas Plant Instruction 3(17)(a) – "Allowance for Funds Used During Construction."

#### *d) The Company Has Not Adequately Demonstrated the Need for the Proposed Disc Modification to the TIRF.*

In proposing its DISC modification to the TIRF, Bay State suggests that a failure in the current regulatory structure within the Commonwealth prevents the Company from sufficiently covering all of its costs. Tr. Vol. I, p. 13. The facts in the record show that this purported failure is apparently not shared by management at Bay State's parent company NiSource, as NiSource notes that of all of its subsidiaries, Bay State has one of the most favorable regulatory environments. Tr. Vol. I, pp. 37-38; citing Company's Response to AG-1-10-A p. 67.

Dr. Dismukes presented results of two separate cost efficiency analyses within his Direct Testimony. Exh. AG/DED-1, pp. 80-93. These cost efficiency analyses are based on publicly available data from the Department of Energy's Energy Information Administration. *Id*. Dr. Dismukes' cost per customer analysis yields two major conclusions. First, Bay State's O&M costs per customer are 14 percent lower than like-situated peer utilities, and 34 percent lower than other peer Massachusetts LDCs. Still, the Company's total O&M costs per customer is some 59 percent higher than the "best performing company" of the Company's peers, and 14 percent higher than other NiSource gas distribution companies. *Id*. Furthermore, Bay State's O&M cost advantage has remained consistent compared to the regional peer average, and has improved relative to other peer Massachusetts LDCs. *Id*. Second, the Company's A&G expenses per customer are some 82 percent higher than the average of like-situated peer utilities, 47 percent higher than the average of peer Massachusetts LDCs, some 449 percent higher than the "best performing company" of the Company's peers, and 118 percent higher than the average of other NiSource gas distribution companies. *Id*. Furthermore, Bay State's A&G costs per customer are becoming worse relative to the regional and Massachusetts peer average. *Id*.

The Department should reject the Company's suggestion that it is the Department's practices and policies that have caused it to be unable to sufficiently cover the Company's costs associated with accelerated infrastructure investment as the Company has failed to prove there is a problem, nor has it demonstrated that any problem is caused by regulatory deficiencies.

### 6. THE DEPARTMENT SHOULD IMPLEMENT A NEW PERFORMANCE METRIC WHICH HOLDS THE COMPANY'S TIRF-RELATED RETURN ON EQUITY ACCOUNTABLE TO ANNUAL LEAK REDUCTION PERFORMANCE.

If the Department does not eliminate the TIRF, Bay State must be held to account for its poor performance under the TIRF. Bay State's approval of the TIRF in D.P.U. 09-30 was clearly predicated on the mechanism attaining certain benefits that the Department found to be in the public interest, including the reduction of leaks from leak-prone facilities and the replacement of bare and unprotected steel infrastructure.

> [The Department concludes] that more aggressive replacement of bare steel in appropriate and desirable from a public policy perspective given the potential benefits to public safety, service reliability, and the environment. *Bay State Gas Company,* D.P.U. 09-30, p. 133, (2009).
>
> …the infrastructure replacement subject to this special ratemaking treatment is limited in both its scale and scope and contains the protections needed to prevent the recovery of any investment deemed imprudent. The funds will be used to replace *a very specific category of non-revenue producing infrastructure, the accelerated replacement of which is viewed by the Department as in the public interest*.

*Id*., pp. 133-134, emphasis added.

The Company, however, has failed to perform in a fashion consistent with Department expectations, and if the TIRF is continued, some form of performance metric should be included in the mechanism. From 2008, the year immediately prior to the adoption of the TIRF, to 2012, active leaks on Bay State system have increased approximately five fold, Exh. AG/DED-1, Schedule DED-18, creating harmful economic, safety, and reliability effects for ratepayers, as well as potentially adding GHG emissions. The Department should take every action to ensure the TIRF mechanism in the future produces the public benefits upon which the original mechanism's approval was predicated. Specifically, the Department should not allow the TIRF to continue without setting enforceable leak reduction targets to benchmark the Company's ongoing performance. The AGO recommends that the Department require the Company to reduce its annual corrosion-related leaks by five percent per year for the Company's mains and seven percent per year for the Company's services. Exh. AG/DED-1, p. 71. This is consistent with the AGO's recommendation in Bay State's prior case, D.P.U. 12-25. D.P.U. 12-25, p. 34-35. In making its recommendation in D.P.U. 12-25, the AGO noted that the leak reduction targets were based on the five-year average leak reduction rates encountered by Bay State prior to the adoption of the TIRF. D.P.U. 12-25, p. 35; Exh. AG/DED-1, p. 71 (2012). Consistent with the AGO's views in D.P.U. 12-25, the proposed performance leak reduction benchmarks are not designed in any way to be punitive to the Company, but are generally designed to return the Company's service performance to rates seen prior to the adoption of the TIRF. D.P.U. 12-25, p. 34.

As an enforcement mechanism the AGO recommends that the Department incorporate into the TIRF a direct one-to-one penalty provision on Bay State's allowed return on investment associated with the mechanism, such that for every percentage deficiency in the Company's leak reduction target, the Company's return on investment is also reduced by a percentage point. Exh. AG/DED-1, pp. 71-72. The AGO further recommends a cap on any increase or decrease to the Company's return on investment be set at 25 basis points to ensure some degree of stability in the Company's overall returns. .

### 7. THE DEPARTMENT SHOULD UPDATE THE EXISTING O&M CREDIT OF $2,542 PER MILE REPLACED TO $2,771 PER MILE REPLACED.

The Department originally adopted an Operations and Maintenance ("O&M") credit of $2,077 per mile of replaced pipe in D.P.U. 09-30 to reflect the avoided O&M cost benefits associated with the replacement of leak-prone pipe. *Bay State Gas Company*, D.P.U. 09-30, p. 120 (2009). In D.P.U. 12-25 the Department approved an updated O&M credit of $2,542 per mile of replaced pipe based upon a revised three year average of historic leak repair costs. D.P.U. 12-25, pp. 60-61. Dr. Dismukes has provided updated estimates of $2,949 per mile based on a three year average, and $2,771 per mile based on a four year average. Exh. AG/DED-1, p. 73. Although the AGO notes that the Department utilized a three year average of historic leak repair costs in establishing an appropriate O&M credit in D.P.U. 12-25, the AGO recommends the Department adopt a new O&M credit of $2,771 per mile based on Dr. Dismukes' four year average.

### 8. SYSTEM MODERNIZATION CREDIT

During a Section 94 rate case, the Department can make adjustments to a formula cost recovery mechanism, like the TIRF. *Attorney General v Department of Public Utilities*, 453 Mass. 191 (2009) (bad debt recovery mechanism), and should do so in this case. The Company explains in its initial filing that as part of its efforts "to increase access to gas service within the service areas" it plans to replace old lower pressure cast iron with plastic pipe that can operate at much higher pressures. Ex. DEM-1, pp. 3, 13-14. The "modernization" plan entails eliminating 897 miles of lower pressure ("LP") main and replacing it with a higher pressure system operating at a maximum allowable operating pressure ("MAOP") of 60 pounds per square inch gauge ("psig") or greater. LP systems can operate at very low pressure, 1/4 psig and below. Ex. ARN-1, p. 6. The Company notes that there would be savings associated the move to higher pressure for at least two reasons. First, a higher pressure system can use smaller diameter mains in order to deliver a like quantity of gas. Second, the Company anticipates that it could reduce the number of regulator stations, used to change pressure on different parts of the system. The Company explains the savings in this way:

> [Switching to plastic pipe] will allow the Company to reduce the number of regulator stations necessary to maintain pressure across the system. Regulator stations are primarily necessitated by the use of facilities operating at less than 60 psig. By going to a higher operating pressure, and being able to deliver larger volumes of gas through smaller pipes, the Company can eliminate both the capital costs incurred over time to install and replace regulators and the O&M expense associated with the annual inspection and maintenance work required for each regulator

Ex. DEM-1, p. 14. According to the filing, the Company has a total of 215 regulator stations and intends to reduce that number to 60. *Id*., pp. 14-17, Tables CMA/DEM 4, 5 &6. The O&M costs associated with regulator stations is substantial, totaling $819,530.00 in the test year. AG RR-3. Once fully implemented, it would reasonable to expect savings in the range of $327,812 in reduced regulator O&M costs on an annual basis. Assuming the same number of regulator stations in the test year, the Company spends on average approximately $3,881 per station.

Although the Company notes regulator O&M savings, it does not propose a method for passing them along to customers on an annual basis, although it does propose to pass along the costs to customers for the replacement pipes that enable these savings on an annual basis. The Company's proposal allocates 100% of the O&M savings to shareholders under the TIRF mechanism, but 100% of the costs to achieve those savings to customers. This allocation is unjust, and apparently has been underway since the Company has been operating the TIRF. The AGO recommends the Department adopt the same approach for a Modernization Credit as it has done for the leaks and credit customers with O&M savings by making the following deduction to the TIRF formula revenue requirement: (O&M $RC_1$ / RI) x $RI_1$-$RI_{x,}$ where "O&M $RC_1$" is defined as the O&M costs for regulator stations in the test year, $RI_1$ is the regulatory station inventory in the test year, and $RI_x$ is the regulator inventory at the end of the calendar year when the Company makes a TIRF filing. Savings from any utility program are meaningful only if they can be passed along to customers through rates in a timely manner. The Company's current TIRF formula does not do so.

### 9. THE DEPARTMENT SHOULD REQUIRE THE COMPANY TO SUBMIT A DEPRECIATION NET-OUT TEST IN ADDITION TO ITS CURRENT TWO-PART TEST, TO INSURE THAT ONLY TRULY INCREMENTAL INVESTMENTS ARE INCLUDED IN TIRF SURCHARGES.

Bay State currently subjects TIRF-related costs to a two-part test to prove that the replacement investments are incremental to those included in base rates. The first element of this two-part test requires the Company to demonstrate that TIRF O&M labor overhead and clearing account burden costs are incremental to the O&M labor overhead and clearing account burden costs being recovered in base rates and the Pension and Post-Retirement Benefits other than Pensions ("PBOP") Expense Factor ("PEF"). Exh. AG/DED-1, p. 74. Under the second element of this two-part test, the Company is then required to allocate any of the O&M labor overhead and clearing account burdens equitably across all capital projects for that year, inclusive of those in the TIRF. Exh. AG/DED-1, pp. 74-75. This two-part test was not an element of the original TIRF approved in D.P.U. 09-30, but was provided during the course of the first annual TIRF cost review in D.P.U. 10-52, and added as a formal requirement by the Department in D.P.U. 12-25. Exh. AG/DED-1, pp. 73-74; D.P.U. 12-25, pp. 56-57.

The AGO notes that Bay State's two-part test is not consistent with the Commonwealth's other national gas utilities. Boston Gas Company and the other National Grid gas companies are each required to perform an additional test to ensure that TIRF investment are incremental to those included in base rates. D.P.U. 12-25, p. 57. This three part test includes both parts included in the Bay State procedure, but includes an additional "depreciation net-out" test that limits the annual level of TIRF-eligible investments to the lesser of (1) the total non-growth capital expenditures in that year less the depreciation expense allowance included in base rates, and (2) the actual TIRF capital expenditures for that year. D.P.U. 12-25, p. 58.

The AGO recommends that the Department require Bay State to add the additional depreciation net-out test to its annual TIRF cost review. This requirement would subject all of Bay State's annual TIRF expenditures to the same three part test required for the National Grid gas companies, assuring (1) uniformity and consistency in the way gas utility TIRF mechanisms are governed; and (2) that only those investments that are truly incremental are included in TIRF surcharges.

### 10. CONCLUSION

The Department's reasoning in approving the TIRF in D.P.U. 09-30 was very clear in that the mechanism's approval was contingent on the many ratepayer protections included in the proposal, and importantly Bay State's commitment to increase pipeline replacement and reduce system leaks. However, in each of its last two rate case filings, Bay State's replacement investment recovery proposals have violated the conditions and protections established by the Department in D.P.U. 09-30 when approving the original TIRF. Having been granted the proverbial "inch," Bay State has continually sought the proverbial "mile." First, in D.P.U. 12-25, Bay State requested that the Department abandon the TIRF in favor of a Rate Year/Rate Base ("RY/RB") proposal that amounted to a fully forecasted test year incorporating 80 percent of Bay State's anticipated (not actual) capital budget. Now, in the current proceeding, Bay State seeks to undermine many of the key ratepayer protection mechanisms included in the original

TIRF approved in D.P.U. 09-30. Moreover, Bay State has clearly failed to reduce active leaks on its system through the accelerated replacement of leak-prone facilities through the TIRF.

The AGO has shown that the Company's proposed modifications to the TIRF mechanism are not consistent with prior Department precedent. In approving the TIRF in D.P.U. 09-30, the Department's based its approval upon what it saw as "three significant differences" from the Company's prior SIR proposals. *Bay State Gas Company*, D.P.U. 09-30, pp. 130-131 (2009). First, the TIRF was based upon actual incremental replacement investments and not representative replacement investments as was proposed in prior cases. *Id*. Second, the TIRF excluded carrying charges. *Id*. Third, the TIRF included a one-percent rate impact cap based on total revenue, a protection missing from prior Bay State proposals. Now the Company proposes to modify two of these fundamental rationales for TIRF approval, by first including carrying charges through the DISC proposal, and significantly weaken the rate impact cap to be 3.75 percent of base revenues instead of total revenues. Furthermore, Bay State's request for the inclusion of carrying costs through the DISC ignores the Department's precedential history against such practices for their detrimental effects to the positive forces of regulatory lag. *Boston Gas Company*, D.P.U. 10-55, pp. 134-135 (2010).

Bay State has also failed to show the necessity for its proposed modifications. Regarding Bay State's proposed modification to the one percent rate impact cap, the AGO has shown that the Company has historically invested far less in pipeline replacement than allowed under the existing one percent rate impact cap. Exh. AG/DED-1, pp.19-20; and Exh. AG/DED-1, Schedule DED-3. In fact, Bay State has only averaged annual investments equal to 56.9 percent of that allowable under the existing rate impact cap. *Id*. The AGO has further demonstrated that going forward the current rate impact cap is not likely to be an investment constraint to the

Company. Exh. AG/DED-1, p. 23; and Exh. AG/DED-1, Schedule DED-8. Regarding its proposed waiver provision, Mr. Stephen Bryant, president of Bay State, stated before the Department that it was "looking at orders of magnitude somewhere in the fifteen to twenty-year range" for replacement of all of the Company's leak-prone infrastructure. Tr. Vol. I, p. 105; *see also* Exh. CMA/SHB-1, p.5. With the utility having 1,082 miles of such infrastructure on its system at the end of 2012,[25] Bay State must average approximately 54 to 72 miles of replacement per year to meet its internal deadline of replacing its entire leak-prone infrastructure in 15 to 20 years. *See* Tr. Vol. I, pp. 105-106. This is a full 42 to 89 percent greater than the Department's threshold adopted in D.P.U. 12-25. Finally, in proposing its DISC, Bay State suggests that a failure in the current regulatory structure within the Commonwealth prevents the Company from sufficiently covering all of its costs. Tr. Vol. I, p. 13. The facts in the record show that this opinion of purported failure is apparently not shared by management at Bay State's parent company NiSource, as NiSource notes that of all of its subsidiaries, Bay State has one of the most favorable regulatory environments. Tr. Vol. I, pp. 37-38; citing Company's Response to AG-1-10-A p. 67.

Finally, perhaps the most egregious problem with the Company's capital cost recovery proposals is the fact that Bay State has not attained the public benefits that the TIRF was clearly predicated on. In approving the TIRF, the Department stated that:

> [The Department concludes] that more aggressive replacement of bare steel in appropriate and desirable from a public policy perspective given the potential benefits to public safety, service reliability, and the environment. *Bay State Gas Company,* D.P.U. 09-30, p. 133 (2009).
>
> …the infrastructure replacement subject to this special ratemaking treatment is limited in both its scale and scope and contains the

[25] The Company possessed 1,103 miles of leak-prone pipeline at the end of 2011, and replaced 21 miles in 2012. *See*, D.P.U. 12-25, Exh. CMA/DAR-1, p. 43. Exh. AG/DED-1, Schedule DED-11.

> protections needed to prevent the recovery of any investment deemed imprudent. The funds will be used to replace a very specific category of non-revenue producing infrastructure, the accelerated replacement of which is viewed by the Department as in the public interest.

*Id*., pp. 133-134.

From 2008, the year immediately prior to the adoption of the TIRF, to the 2012 test year, active leaks on Bay State system have increased approximately five fold. Exh. AG/DED-1, Schedule DED-18. The time is ripe for the Department to take a measured review of its current enforcement mechanism adopted in D.P.U. 12-25. The AGO has recommended in the last Bay State rate case that the Department adopt strict leak-rate based performance targets for Bay State to meet. The AGO renews this argument, as the TIRF has clearly not been delivering one of the core public benefits its approval was premised on. Specifically, the AGO recommends that the Department replace its current enforcement mechanism adopted in D.P.U. 12-25, and replace it with a strict leak-rate based performance target of a five percent per year reduction in corrosion-related leaks from mains and seven percent per year reduction in corrosion-related leaks from services. Exh. AG/DED-1, p. 71. The AGO further recommends the Company's allowed return on equity under the TIRF be directly conditioned on adherence to the leak-rate performance target, such that if the Company misses its leak reduction target by one percent, its allowed return on equity under the TIRF would also be reduced by one percent. Exh. AG/DED-1, p. 72.

For all of the foregoing reasons, the AGO respectfully requests that the Department to eliminate the TIRF because of the expected annual rate case filings, or in the alternative, (1) reject the Company's proposed modifications to the TIRF, (2) implement adopt strict leak-rate based performance targets for Bay State, thus ensuring the TIRF provides benefits to ratepayers in the form of reduced system leaks, and (3) adopt the AGO's recommended modifications.

## F. Rate Base

### 1. THE COMPANY'S PROPOSAL TO ADJUST ITS RATE BASE FOR NON-REVENUE PRODUCING CAPITAL SPENDING THROUGH JUNE 30, 2013 SHOULD BE REJECTED

The Company is proposing to adjust its rate base for what it describes as non-revenue producing capital spending through June 30, 2013. As described by Mr. Gore, the post-test year plant additions include non-revenue producing depreciable plant investment and capital investment for information systems. Exh. CMA/JTG-1, pp. 29-30. The pro forma rate base proposed by the Company thus includes all plant in service as of December 31, 2012 plus non-revenue producing plant additions for the six months ending June 30, 2013. The Company also adjusted rate base for related growth in depreciation and amortization reserve and accumulated deferred income taxes. The net effect of the Company's proposal is to increase pro forma rate base by $14,620,642. Exh. CMA/JTG-2, 10/16/13 Update, Schedule JTG - 13. At the Company's requested rate of return, this adjustment to rate base increases the Company's return requirement by $1,897,562 (including associated income taxes).

In addition, certain plant related expenses increase with the post-test year additions to plant in service. Those expenses include: increased depreciation expense of $411,662, increased amortization expense on intangible plant of $1,006,804 and increased property taxes of $199,320 on the post-test year plant additions. The additional return requirement plus expenses total $3,515,348. Grossed up for uncollectible accounts, the total revenue requirement effect of the Company's proposed adjustment is $3,577,962.

The Department should reject the Company's proposal to adjust the test year rate base for non-revenue plant additions through June 2013, and the post-test year plant additions and related expenses should be eliminated from the Company's revenue requirement. As noted by Mr. Effron:

> First, the Company’s adjustment for post test year plant additions is incomplete. As noted above, the Company’s adjustment excludes revenue producing plant additions. Consistent with the exclusion of revenue producing plant from the pro forma adjustment to rate base, the Company does not include incremental revenues from new business in the calculation of its revenue deficiency. To the extent that the revenues from new business exceed the cost of the incremental revenue producing plant additions, the revenue requirement effect of the post test year plant would be mitigated, but the Company’s proposal does not take this into account.
>
> Second, the Company’s adjustment, if accepted would cause a mismatch between the plant included in rate base and the benefits produced by that plant.

Exh. AG-DJE-1, at 26

Mr. Effron elaborated on this second point:

> The inclusion of the NIFIT system in the post-test year plant additions illustrates the nature of this mismatch. … The NIFIT system accounts for … over half of the increase to net plant in service. … I described the benefits of NIFIT earlier in this testimony. As NIFIT was not scheduled to go into service until June 2013, the test year does not reflect any of those benefits, and the Company has not proposed any pro forma adjustment to recognize the benefits. It would be inconsistent to adjust rate base to include the cost of NIFIT without any adjustment to recognize the benefits of this system. Yet that is what the Company’s adjustment to rate base for post test year plant additions entails. The mismatch between the Company’s treatment of the costs and benefits associated with the NIFIT project demonstrates the inconsistencies implicit in its proposed adjustment for post test year plant additions.

Exh. AG-DJE-1, at 27

The test year in this case is the twelve months ended December 31, 2012. Although the Company’s proposed adjustment is based on actual additions to plant in service, there can be no dispute that it is an attempt to move the determination of its rate base beyond the end of the specified historic test year. In that regard, it represents a move towards a future test year, similar to the Company's "rate year/rate base" proposal in D.P.U. 12-25. In that case, the Department found "a future test year would represent a radical change from the Department's current ratemaking practice. *See* D.P.U. 07-50-A, p. 51." D.P.U. 12-25, p. 18) The Department has not only rejected the use of a future test year but has also "rejected more discrete proposals within general base rate filings that it considered consistent with a future test year. *See*, e.g., *Western Massachusetts Electric Company*, D.P.U. 10-70, at 184-185 (2011)." D.P.U. 12-25, p. 18.

The Company's proposal is a departure from the use of a historic test year to determine rates and is a move in the direction of a future test year, which is inconsistent with "the well-established Department precedent that base rates are established based on an historic test year, adjusted for known and measurable changes. *See Eastern Edison Company*, D.P.U. 1580, pp. 13-17, 19 (1984); *Massachusetts Electric Company*, D.P.U. 136, p. 3 (1980); *Chatham Water Company*, D.P.U. 19992, p. 2 (1980); *Massachusetts Electric Company*, D.P.U. 18204, p. (1975); *New England Telephone & Telegraph Company*, D.P.U. 18210, pp. 2-3 (1975); *Boston Gas Company*, D.P.U. 18264, at 2-4 (1975)." D.P.U. 12-25, p. 17.

The need for regulatory lag, however, is not the only reason to reject the Company's proposed post-test year capital additions. First, as the Company's witness, Mr. Gore admitted, the proposed post-test year dollar amounts to be added to plant are unaudited by any independent outside auditor. RR-AG-12. Use of the audited 2012 calendar test year financial accounting information in this rate case provides the Department with some assurance that the income statements and balance sheet amounts used to develop the cost of service are known and measureable. Then, when the Department allows post-test year adjustments introduced during the proceedings like property taxes and rate case expenses, the record has actual property tax bills and vender invoices that provide substantial evidence that the amounts are known and measureable. *Massachusetts Electric Company/Nantucket Electric Company*, D.P.U. 09-39-A, p. 27 (2010). No such evidence has been provided here to demonstrate that any of the Company's post-test year capital additions exist, or equally important, that they were, in fact, actually providing service to customers.

Without such independent proof of the Company's newly proposed post-test year adjustments, there is no way that the other parties and the Department can verify the amounts claimed by the Company. These unaudited amounts are nothing more than numbers written on a piece of paper and should be given no weight in this proceeding. In fact, they do not constitute substantial evidence, because they lack any indicia of reliability. *See, e.g. Embers of Salisbury, Inc. v. Alcoholic Beverages Control Commission,* 401 Mass. 526, 530 (1988) ("Although in that case we said that '[i]f the pertinent evidence is exclusively hearsay, that does not constitute 'substantial evidence' even before an administrative tribunal,' [*Sinclair v. Director of the Division of Employment Security*, 331 Mass. 101, 103], the line we were drawing was not between evidence admissible in a court and evidence that is inadmissible because of the rules of evidence observed by courts, but between evidence having indicia of reliability and probative value and that which does not."). Therefore, the Department must also reject the Company's proposed post-test year additions in this case, since there is no substantial independent verification to support any of those amounts.

The Department rejected the Company's "rate year/rate base" proposal in D.P.U. 12-25. As the Company's proposal to adjust its rate base for post-test year plant additions in the present case would be a move towards a future test year, the Department should reject that proposal as well.

### 2. THE COMPANY'S ADJUSTMENTS TO THE REVENUE REQUIREMENT RELATED TO EP&S SALE MUST BE MODIFIED

Energy Products and Services ("EP&S") is a residential retail services business that Bay State had operated for many years. EP&S provides residential retail services including the sale and installation of heating equipment, inspection and repair of heating equipment (including the Guardian Care warranty program), and leasing of heating equipment. Although these are not regulated public utility services, EP&S revenues and expenses (except for the sale and installation of heating equipment) had been included with utility operations, and the investment in EP&S facilities had been included with the utility rate base for the purpose of determining the utility revenue requirement. EP&S was sold to AGL Resources, Inc. ("AGL") on January 31, 2013.

AGL paid a total of $120 million to purchase EP&S along with two other NiSource retail service operations, NiSource Retail Services ("NRS") and the NIPSCO Gas business unit ("NIPSCO"). Of the total sale price of $120 million, $39.4 million was allocated to Bay State's EP&S business. The book value of the assets sold was $19.9 million. After the expenses of the sale, the net gain calculated by Bay State was approximately $18.1 million. Exh. CMA/SHB-1, pp. 19-20.

To recognize the effect of the sale of EP&S, the Company has 1) reduced pro forma test year operating expenses to reflect the elimination of expenses related to the EP&S sale, including operation and maintenance expenses of $4,773,987 and depreciation of $2,583,760 (implicitly eliminated in the calculation of pro forma depreciation expense on plant in service exclusive of EP&S), 2) reduced rate base by $18,527,502 to reflect the sale of EP&S assets (Exh. CMA/JTG-2, 9/3/13 Update, Schedule JTG-13), and 3) reflected amortization of $5,767,225 of the gain on the sale of EP&S by means of a revenue credit. Exh. CMA/JTG-2, 9/3/13 Update, Schedule

JTG-4. The purpose of the revenue credit is to offset the EP&S operation and maintenance expenses that were not eliminated as a result of the sale, $2,748,578, and to provide compensation to ratepayers for the loss of the EP&S contribution to the cost of service from the EP&S income in excess of what the income would be based on the authorized utility rate of return, $3,151,647, offset by revenues of $133,000 for services provided to AGL. Exh. CMA/JTG-2, 9/3/13 Update, Page 3. In effect, the revenue credit holds customers harmless from the loss of the EP&S contribution to the Company's revenue requirement for utility services.

Certain adjustments to the Company's treatment of the gain on the sale of EP&S are necessary. First, until the gain is amortized back to ratepayers, the Company retains the present value of that gain. The benefit of the cash retained by the Company until the pass through to customers should be recognized by means of a return calculated on the unamortized net-of-tax balance of the gain. The amount credited to ratepayers should then be deemed to consist of the return on that unamortized balance plus the amortization necessary to hold ratepayers harmless from the EP&S sale. Exh. AG-DJE-1, p. 11. Second, the Company has not demonstrated that the $2,748,578 of retained EP&S expenses appropriately remains in the utility cost of service. Therefore, these expenses should be removed from the CMA revenue requirement and the amortization of the gain included in the hold harmless credit should be reduced by the same amount. Exh. AG-DJE-1, p. 13.

The Company did not dispute Mr. Effron's testimony, that until the gain on the EP&S sale is amortized back to ratepayers, the Company retains the present value of that gain. Rather in his rebuttal testimony, Mr. Bryant stated that Mr. Effron's proposal to recognize a return on the unamortized gain on the sale of assets "is not in any way consistent with the Department's longstanding precedent on the treatment of gains in the ratemaking process." Exh. CMA/SHB-

Rebuttal-1, p. 18). However, when asked in AG Information Request 35-2 to provide specific citation to the Department precedent to which Mr. Bryant was referring, the Company declined to provide any specific citations, noting only that the referenced testimony was "based on a discussion with the Company's counsel regarding the Department's precedent on the gain on a sale of utility assets." Thus, the Company has failed to cite any Department precedent for excluding the recognition of a return on the unamortized balance of the gain until the gain is returned to customers.

Mr. Effron, however, was able to cite cases where carrying charges were recognized on the unamortized proceeds of asset sales:

> In association with the electric restructuring in the late 1990's, electric utilities in Massachusetts divested their generating assets. Prior to divestiture, the generating assets had been treated as part of the Company's utility operations for ratemaking purposes. That is, the assets had been included in rate base and the related expenses in the utility's cost of service. The proceeds from the divestiture of the generating assets were credited to ratepayers by means of a residual value credit ("RVC"). The RVC consisted of amortization of the proceeds plus a return on the unamortized balance at the weighted average cost of capital, grossed up for income taxes. See, for example, D.T.E. 96-25 and 97-94, Massachusetts Electric Company and Nantucket Electric Company; D.T.E. 97-120, Western Massachusetts Electric Company; and D.T.E. 97-115, Fitchburg Gas and Electric Company.

Exh. AG-DJE- Surrebuttal-2, p.

While the electric utilities' divestiture of their generating assets is obviously not identical in all respects to Bay State's sale of the EP&S unit, the transactions are similar in that as with the electric utilities' divesture of the electric generating assets, the Company's sale of EP&S entails the sale of a business unit that had been treated as a component of regulated utility operations prior to the sale. The relevant principle is that when the proceeds from the disposition of assets are being amortized to ratepayers, the total credit to ratepayers should include a return on the unamortized gain until it is fully amortized.  That principle applied in the case of the electric utilities generating assets and it should also apply with regard to Bay State's sale of EP&S.

Mr. Bryant also contended that "even if such carrying charges were to attach, it (sic) would not be at the weighted cost of capital and it would not apply to the entire balance at the outset of the amortization, without regard to the amortization and reduction of that balance as the amount is amortized." Exh. CMA/SHB-Rebuttal-1, p. 19.  However, Mr. Bryan offered no alternative rate that should be applied to the unamortized balance, and did not explain why a carrying charge rate other than the weighted cost of capital would be appropriate.  With regard to the second criticism, Mr. Effron agreed that the return component would decline over time as the gain was amortized and that the return component of the credit at the time of the Company's next case would be lower.  Tr. Vol. X, pp. 1077-78.  But that does not affect the computation of the return in the present case.

Mr. Effron calculated an after-tax gain of $9,000,000. Exh. AG-DJE- Surrebuttal-2, p. 5 (Income taxes are netted against the gain only for the purpose of calculating the return.  The amortization amount is still based on the pre-tax gain.)  Applying the pre-tax rate of return of 11.11% from D.P.U. 12-25 to this balance, the return on the unamortized balance of the net-of-tax gain is $999,900.  Mr. Effron was asked to calculate the annual return on the gain on sale of EP&S, with the amount on DJE-2-Supplemental adjusted to reflect 1) the annual contribution to the CMA revenue requirement foregone by the Company from February 1, 2013 to March 1, 2014, and 2) the annual return on the gain retained by shareholders from February 1, 2013 to March 1, 2014.  DPU RR-23; Tr. Vol. X, pp.1079-84.  Mr. Effron calculated that with these modifications, the return component of the customer credit would be $845,030.  DPU RR-23.

The AGO General agrees that if the Department finds that the gain on the sale of EP&S should be adjusted to reflect the annual contribution to the Bay State revenue requirement foregone by the Company from February 1, 2013 to March 1, 2014, and the annual return on the gain retained by shareholders from February 1, 2013 to March 1, 2014, then the return component of the credit should be reduced from $999,000 to $845,030.

With regard to the $2,748,578 of retained EP&S expenses, it is the Company's position that these expenses "remain in the cost of service for the time being." Exh. CMA/JGT-1, p. 18. With those expenses remaining in the cost of service, the necessary amortization of the gain to hold customers harmless is increased accordingly. Of the EP&S costs remaining with Bay State and being charged to operation and maintenance expenses, $1,389,330 are direct labor, non-productive labor, and related fringe benefits. RR DPU-24. Other than stating that the employees to whom these expenses pertain are being redeployed in distribution functions, the Company has not adequately demonstrated how these employees, who had been providing service to EP&S, are now being productively employed in providing distribution service. With regard to the non-directly assigned labor costs such as fleet, stores, outside services, and allocated call center, dispatch, and supervision costs, the Company did not provide any explanation in its direct case of why it is appropriate to include these expenses in the cost of service on a continuing basis.

In his rebuttal testimony, Mr. Bryant presented testimony that attempted to establish that the retained EP&S employees are being productively deployed in the Bay State distribution business. Exh. CMA/SHB-Rebuttal-1, pp. 13-18. This testimony mainly described what the relevant employees did in 2012 and shows that their time is being charged to Bay State in 2013. There is no dispute that employees' time is actually being charged to Bay State in 2013. However, Mr. Bryant did not describe any increase in the Company's distribution work requirements that suddenly came into existence at the time that EP&S was sold. He did describe activities that would plausibly entail additional work requirements over time (Exh. CMA/SHB-Rebuttal-1, at 17-18), but this did not establish any immediate increase in the Bay State work requirements that just happened to coincide with the EP&S sale.

As to the non-directly assigned labor costs such as fleet, stores, outside services, and allocated call center, dispatch, and supervision costs, all Mr. Bryant could say was that these costs "are correlated with the labor now redeployed to distribution operations" and, as such "are proper for inclusion in the cost of service." Exh. CMA/SHB-Rebuttal-1, p. 18. Mr. Bryant offered no evidence of how the relevant costs are correlated with the redeployed labor, or even assuming that such correlation exists, why that would imply such costs are proper for inclusion in the cost of service.

In summary, Mr. Bryant did not establish any sudden increase in the Bay State work requirements on February 1, 2013 necessitating an additional $2.7 million in additional distribution operating expenses. The expenses that had been charged to EP&S prior to that date should not be included in the Bay State cost of service in this case.

Recognizing carrying charges on the unamortized balance of the gain and eliminating the retained EP&S expenses from the cost of service does not affect the base rate revenue requirement in the present case. However, these modifications will reduce the amortization necessary to hold customers harmless and will increase the balance available for amortization prospectively. As noted by Mr. Effron:

> Increasing the balance available for amortization can both enhance the amount of the prospective amortization and extend the period over which the gain is amortized. To the extent that the amortization is greater and continues longer into the future, it will be available to offset expenses stranded by the sale of EP&S. The Company should be able to recover the expenses that had

> previously been absorbed by EP&S only if those expenses are actually necessary for the provision of distribution service and not simply because there is no vehicle for recovery other than the utility revenue requirement. The longer the amortization of the gain extends into the future, and the larger the amount of that amortization, the less likely it is that ratepayers will be required to compensate the Company for expenses stranded by the sale of EP&S.

Exh. AG-DJE-1, at 14

To protect ratepayers prospectively, the Department should include carrying charges in the pass back of the gain on the EP&S sale and should eliminate the expenses formerly charged to EP&S from the Company's cost of service in the present case.

### 3. CASH WORKING CAPITAL – COLLECTION LAG

In determining its cash working capital request, Bay State prepared a new lead/lag study that was based, for the most part, on data for the test year ended December 31, 2012. The lead lag study used by Bay State was summarized and included as Exhibit CMA/BEE-2. In preparing the lead lag study, the Company used 2012 test year data, with the exception of the collection lag component of the revenue lag which was based on 2011 data. Tr. Vol. V, p. 476. The 2011 collection lag component of the revenue lag was 33.92 days and was developed for the prior rate case, D.P.U. 12-25. Exh. CMA/BEE-1, pp. 5-6. The Company calculated that the collection lag would be 27.17 days had it been based on 2012 test year data. Exh. CMA/BEE-1, p.7. Thus, by selectively choosing to base the collection lag on 2011 data instead of 2012 test year data, the resulting collection lag, and the revenue lag, included Bay State's cash working capital was 6.75 days longer (33.92 – 27.17 = 6.75). Tr. Vol. V, pp. 481-492.

In explaining why he used 2011 data for a single component of the lead/lag calculations when the remaining lead/lag day calculations relied upon 2012 data, Bay State witness Brian E. Ellis indicated that "Deviations from normal weather impact Accounts Receivable balances for the Company's budget payment plan customers." Thus, Mr. Ellis attributed the changes in the collection lag that was realized between 2011 and 2012 to warmer weather in 2012 as compared to 2011. Tr. Vol. V, pp. 476-477. Exh. CMA/BEE-1, pp. 6-7.

However, this position ignores the fact that other factors beyond the weather impacts on receivable balances associated with budget payment plan customers may have caused the reduction to the collection lag between 2011 and 2012. For example, Company witness Ellis agreed that any improvements in general economic conditions that occurred between 2011 and 2012 would potentially impact the collection lag, and that the Company had no way of measuring the impact of economic changes in the collection lag. Tr. Vol. V, p. 477. Mr. Ellis also indicated that he was unable to do any study or analysis to determine if the collection lag may have also declined in 2012 compared to 2011 due to factors other than the warm winter impact. *Id*.

The contention that the deviations from normal weather impact the budget payment plan customers and that this would have a significant impact on the collection lag in 2012 also ignores the fact that the majority of Bay State's customers do not participate in the budget payment plan. At the end of the 2012 test year, 83% of the Company's customers did not participate in the budget payment plan. Exh. DPU-3-6. Company witness Ellis agreed that only 17 percent of the customers participated in the budget payment plan at the end of 2012 and that the majority of the customers did not participate in the plan. Tr. Vol. V, pp. 478 – 480.

The cash working capital requirement should be recalculated to include the collection lag based on the 2012 test year data, consistent with the remaining components of the lead/lag study and calculations which relied on 2012 test year data. It would be inappropriate to allow Bay

State to selectively change the test period for one single component of the lead/lag study when it does not like the results of its analysis for that single component.

Using the 2012 collection lag would result in a 6.75 day reduction to both the collection lag and the overall revenue lag in this case. If the 2012 collection lag had been used, the total revenue lag would be 43.59 days. Additionally, the weighted net lag days for Other O&M working capital would decline from the 32.74 days shown in the lead/lag study (Exhibit CMA/BEE-2) to 25.99 days. Tr. Vol. V, pp.482 – 483. As a result, Company witness Ellis agreed that the Other O&M working capital percentage that was used by the Company in calculating the cash working capital request in this case would decline from 8.945% to 7.101%. *Id*. In calculating the final amount of Allowance for Other O&M Cash Working Capital to include in rate base, the Commission should apply the 7.101% Other O&M working capital percentage based on use of the 2012 collection lag to the final, adjustment total costs applicable to cash working capital instead of the 8.945% factor calculated by Bay State which used the 2011 collection lag.

The final version of adjustment to rate base for the allowance for Other O&M Cash Working Capital provided by the Company shows that Bay State applied the 8.945% Other O&M working capital percentage to "Total Costs Applicable to Cash Working Capital of $126,796,269, resulting in its proposed cash working capital adjustment of $11,341,926 ($126,796,269 x 8.945% = $11,341,926). Exh. CMA/JTG-2 10/16/13 Update, Schedule JTG-15. Replacing the 8.945% Other O&M working capital percentage with 7.101% would result in a cash working capital adjustment of $9,003,803 ($126,796,269 x 7.101% = $9,003,803). Thus, cash working capital should be reduced by a minimum of $2,338,123 ($11,341,926 - $9,003,803) in order to include the impacts of the actual 2012 test year collection lag instead of the 2011 collection lag. Additionally, the impact of any adjustments to O&M expenses and taxes other than income adopted by the Commission in this case would also further reduce the cash working capital amount as they would reduce the amount to which the 7.101% factor is applied.

## G. Operations and Maintenance Expenses

### 1. THE COMPANY HAS IMPROPERLY INCLUDED 2014 NON-UNION WAGE INCREASES IN PRO FORMA TEST YEAR OPERATION AND MAINTENANCE EXPENSES

The Company's proposed adjustment to test year payroll expenses for wage and salary increases is shown on CMA/JTG-2, 10/16/13 Update, Schedule JTG-6, Page 7. As can be seen on this schedule, the Company's pro forma adjustment annualizes the wage and salary increases in the 2012 test year and also adjusts the test year payroll expense for union and non-union increases in 2013 and 2014. The proposed adjustment to payroll expense for non-union increases in 2014 does not meet the Department standards for recognition of such increases and should be eliminated from the Company's cost of service.

In Bay State's last rate case, D.P.U. 12-25, the Department summarized the criteria for recognition of post-test year non-union wage increases: "To recognize an adjustment for increase in non-union wages that takes place prior to the issuance of an Order, a company must demonstrate that such increases are known and measurable and also reasonable. *See* D.P.U. 08-35, pp. 81-82, 87; D.P.U. 92-250, p. 35; D.P.U. 1270/1414, p. 14. To recognize an adjustment for an increase in non-union wages that occurs post-Order, a company must demonstrate that: (1) there is an express commitment by management to grant the increase; (2) there is an historical correlation between union and non-union raises; and (3) the non-union increase is reasonable. D.P.U. 96-50 (Phase I), p. 42; D.P.U. 95-40, p. 21; D.P.U. 1270/1414, p. 14. In addition, only non-union salary increases that are scheduled to become effective no later than the midpoint of the first twelve months after the date of the Order may be included in rates. D.P.U. 85-266-A/85-271-A, p. 107." D.P.U. 12-25, pp. 151-152.

With regard to the 2014 non-union wage increases, all the Company could offer in its direct case was that management expects to grant such increases in June of 2014. Exh. CMA/KKC-1, pp. 14-15. A statement that management expects such an increase to take place is not evidence of "an express commitment by management to grant the increase." Therefore, because Bay State failed to meet the Department's threshold criterion for inclusion of the 2014 non-union wage increases in its cost of service, "the effect of the 2014 non-union increase should be eliminated from the Company's revenue requirement. Exh. AG-DJE-1, p. 17.

In the Company's rebuttal case, Company witness Bryant did not disagree with Mr. Effron's testimony that the Company had not produced the written confirmation of the 2014 non-union wage increase as required by the Department. Exh. CMA/SHB-Rebuttal, p. 19. However he did not agree that the Department should simply exclude this cost from the cost of service. *Id*. Mr. Bryant did not identify any inconsistency between the AGO's proposal to eliminate the 2014 non-union wage increase from the cost of service and the Department's established practice for treating post-test year non-union wage increases. Rather, the Company requested that the Department modify its standards for the inclusion of post-test year wage increases in the cost of service.

The Company never presented any evidence of an express commitment by management to grant the 2014 non-union wage rate increase, nor has the Company presented any compelling reason why the Department should abandon its well established standards for determining what post-test year wage increases are includable in the cost of service and treat CMA differently from other utilities. Therefore, based on Department precedent, the effect of the 2014 non-union increase should not be included in the Company's revenue requirement.

The 2014 non-union payroll adjustment increases pro forma operation and maintenance expenses by $203,697. Exh. CMA/JTG-2, 10/16/13 Update, Schedule JTG-6, Page 7. Based on the effective payroll tax rate of 6.96% (Exh. CMA/JTG-2, 10/16/13 Update, Schedule JTG-9, Page 6), the associated payroll taxes are $14,177. Therefore, elimination of the 2014 non-union wage increase and associated payroll taxes reduces pro forma test-year operating expenses by $217,874.

### 2. THE DEPARTMENT SHOULD NOT INCLUDE THE FULL AMORTIZATION OF THE NIFIT & WMS SYSTEMS' DEFERRED O&M COSTS IN THE COST OF SERVICE AT THIS TIME

The Company proposed to defer and amortize certain operation and maintenance expenses associated with the NiSource financial transformation program ("NIFIT") and Work Management System ("WMS"). As explained by Mr. Gore, the Company would create a regulatory asset for the NIFIT and WMS implementation O&M costs and amortize that regulatory asset through base rates over a three-year period. Exh. CMA/JGT-1, p. 22.

The WMS was put in service October 23, 2012. The Company incurred $1,779,971 of implementation O&M costs in 2012 and an additional $64,014 in 2013, for total costs of $1,843,985. Exh. CMA/JTG-2, 10/16/13 Update, Schedule JTG-6, Page 16.

The NIFIT project was implemented in June 2013. The Company incurred $1,276,337 of implementation O&M costs associated with the NIFIT project in 2012 and an additional $1,430,405 in 2013, for total costs of $2,706,742. *Id*.

In total, the Company is proposing to create a regulatory asset of $4,550,727 and to amortize that regulatory asset over three years, resulting in annual amortization of expense of

$1,516,909.  The Company is proposing to include that amortization in the revenue requirement in this case.

The full amount of the amortization of the NIFIT and WMS regulatory assets should not be included in the Company's cost of service at this time, as doing so would cause a mismatch between the costs of the systems and benefits of the systems.  Just as there are costs associated with these systems, there are also benefits, and those costs and benefits should be properly matched in determining the Company's revenue requirement in the present case.

In D.P.U. 12-25, the Company provided a description of the costs and benefits associated with the WMS.  The benefits noted include: provision of a complete system that is extensively integrated, improvement of ability to manage compliance programs, standardization of processes and data, and elimination of operations use of Progress based systems.  The Business Case for the WMS did not quantify these benefits, but that does not mean that there will be no benefits. Exh. AG-DJE-1, pp. 18-19.

Exhibit CMA/RAF-5 in the present case is the Business Case for NIFIT.  The benefits described in the Business Case include: operation form a common general ledger and chart of accounts for all NiSource companies, ability of NiSource technologies to "talk" to each other, creation of a common electronic data repository for financial information, improved compliance, increased business unit cost management capabilities, and increased NiSource Corporate Service operational efficiencies.  The Business Case states that no metrics were provided to measure these benefits "due to the nature of the case not having easily quantifiable cost savings or revenues to offset the capital outlay."  Exh. CMA/RAF-5, at 3).  Again, because these benefits are not easily quantifiable does not mean that they do not exist.  *Id.*

While the Company is proposing to reflect a full year of amortization of the regulatory assets in the cost of service in the present case, neither of the systems was in operation for the full 2012 test year, and thus the full annual benefits of these systems were not realized in the test year in this case. The WMS was not put into service until October 2012, so the test year reflects only a portion of the annual level of benefits associated with this system. As NIFIT was not implemented until June of 2013, none of the benefits of that system would have been experienced during the 2012 test year. It would be inconsistent to burden ratepayers with the costs of these systems without recognition of the offsetting benefits.

The WMS went into service in late October of 2012. Therefore, it is reasonable to expect that about two months of benefits related to that project were realized in the test year. If the total cost of $1,843,985 is amortized over three years, the annual amortization is $614,662 per year. Two months of that annual amortization is $102,444. That is the amount of amortization that should be reflected in the pro forma test year operating expenses. In addition, the three year amortization period should be deemed to have begun on November, 1 2012. It is true that the rates being paid by customers did not reflect the amortization expense at that date. But it is equally true that the rates being paid by customers also did not reflect the benefits of the WMS at that date. That is, any benefits of the WMS will have been retained by shareholders up until the date of effective rates in this case. Consistent with the retention of those benefits, the shareholders should also absorb the costs of the system up until that time, including the amortization of the deferred O&M implementation costs. Exh. AG-DJE-1, p. 20.

NIFIT was not implemented until June 2013. Accordingly, no benefits of NIFIT are included in the 2012 test year. Therefore, no amortization of the deferred NIFIT O&M costs should be included in the Company's cost of service at this time. The amortization of the costs should be deemed to have commenced at the time that NIFIT became operational, in order to achieve a proper matching between costs and benefits. That is, the benefits of the system should pay for the costs of the system, even before the costs (and the benefits) are explicitly reflected in rates. Just as the rates being established in this case will not reflect the amortization of the deferred NIFIT costs; neither will the rates reflect the benefit of that system. Exh. AG-DJE-1, pp. 20-21.

Company witnesses Fontaine and Gore responded to Mr. Effron's testimony on WMS and NIFIT by misrepresenting his position on this issue. Mr. Fontaine erroneously claimed that it was Mr. Effron's recommendation that "the Company defer recovery of the NIFIT O&M costs until some future unspecified date at which time the Company would produce a cost benefit analysis demonstrating that the NIFIT benefits were greater than the NIFIT costs," (Exhibit CMA/RAF-Rebuttal, at 2). This was not Mr. Effron's recommendation. Rather, as he explained, he was recommending that:

> the recovery of NIFIT costs be matched to the realization of NIFIT benefits. NIFIT was not in service during the 2012 test year in this case, and none of the NIFIT benefits were realized in the test year. Therefore, the costs of the NIFIT system should not be included in the Company's revenue requirement in the present case. I did not propose to make recovery of NIFIT costs in the Company's next rate case (at which time the system will presumably have been in service for the whole test year) contingent on the production of a cost benefit analysis demonstrating that the NIFIT benefits were greater than the NIFIT costs.

Exh. AG-DJE-Surrebuttal-1, at 2

Similarly, Mr. Gore asserted that Mr. Effron's "recommendation appears to rest on the premise that the costs should be deferred until the Company has made a showing that the benefits of NIFIT outweigh the costs." Exh. CMA/JTG-Rebuttal, p. 14. Mr. Effron responded that:

> That is not my recommendation. I am not recommending a disallowance based on prudence or on the failure to establish that the benefits of the system outweigh its costs. Again, my recommendation is based on a proper matching of costs and benefits. As the test year in this case does not reflect the benefits of the system, the revenue requirement should not reflect the cost of the system.

Exh. AG-DJE-Surebuttal-1, pp. 3-4

Mr. Fontaine stated that "the recovery of the prudently incurred NIFIT costs, including O&M costs, appropriately commences in June 2013, NIFIT's in-service date." Exh. CMA/RAF-Rebuttal, p. 2. Mr. Effron said as much in his direct testimony. The NIFIT in service date is also when the Company will begin realizing the benefits of the system, none of which have been reflected in the determination of the Company's revenue requirement in this case.

Mr. Gore testified that "[t]he prudency of WMS has been amply demonstrated in this proceeding and, since WMS was placed in service in October 2012, it is considered used and useful. Customers began benefitting from WMS as of it's in service date." Exh. CMA/JTG-Rebuttal, p. 16. That is precisely what Mr. Effron's proposal reflects. As the WMS went into service in late October of 2012, it is reasonable to expect that about two months of benefits related to that project were realized in the test year, and Mr. Effron has proposed to reflect two months' amortization of deferred WMS O&M costs in the Company's revenue requirement.

Mr. Effron calculated a pro forma test year amortization expense of $102,444, consisting of two months' amortization of the WMS. This is $1,414,465 less than the pro forma amortization expense of $1,516,909 calculated by the Company (Exh. CMA/JTG-2 10/16/13 Update, Schedule 6, Page 16). Accordingly, the NIFIT and WMS amortization included in pro forma test year operation and maintenance expense should be reduced by $1,414,465.

### 3. SERVICE COMPANY CHARGES FROM NISOURCE CORPORATE SERVICE COMPANY

#### *a) Charges to Bay State from NCSC Continue to Escalate Exponentially*

Under a service agreement between the Bay State and NiSource Corporate Company ("NCSC") the Service Company provides Bay State with the following services: accounting and statistical services; auditing services; budget services; business promotion services; corporate services; depreciation services; economic services; electronic communications services; employee services; electronic communication services; employee services; engineering and research services; gas dispatching services; information technology services; information services; insurance services; legal services; office space; officers; operations support and planning services; purchasing, storage and disposition services; rate services; tax services; transportation services; treasury services; land surveying services; customer billing; collection and contact services; and miscellaneous services. Exh. AG-1-26, Attachment AG-1-26, pp. 1-15. While the list of services provided under the agreement is long, it does not justify the continual exponential increases in charges to Bay State from NCSC. The AGO expressed great concern in the prior rate case, D.P.U 12-25, with the continual escalation of the charges, and must do so again as the charges have continued to grow unchecked. Over the last four years, Bay State's operation and maintenance costs have increased 16.3% and charges to Bay State from NCSC have increased 47.9% during the same four year period. Tr. Vol. I, pp. 33-34. The table below presents the significant increases in the amounts billed by NCSC to associate companies and to Bay State, for each year, 2008 through the 2012 test year:

| | 2008 | 2009 | 2010 | 2011 | 2012 |
|---|---|---|---|---|---|
| 1. Total Billed to Associate Companies ($) | 372,307,729 | 377,469,976 | 409,702,831 | 447,336,937 | 458,092,313 |
| 2. % Change | | 1.39% | 8.54% | 9.19% | 2.40% |
| 3. Total Billed to Bay State ($) | 29,544,086 | 36,798,922 | 38,622,372 | 40,395,028 | 43,682,931 |
| 4. % Change | | 24.56% | 4.96% | 4.59% | 8.14% |
| 5. % of Bay State to Total (L. 4 / L.1) | 7.9% | 9.7% | 9.4% | 9.0% | 9.5% |

Exh. AG-DR-1, p.7.

As shown in the above table, the charges from NCSC to Bay State increased by $14.1 million, a whopping 48%, between 2008 and the 2012 test year. The charges to Bay State increased by 8.14% during the test year alone. Of the total $43,682,931 charged to Bay State from NCSC in the 2012 test year, $38,730,911 was included in Bay State's test year per book O&M expenses. Exh. AG-DR-1, p. 9; Exh. AG-1-89. The remaining $4,952,020 was recorded in other areas, such as capital/plant. Of the $38,730,911 recorded in test year O&M expenses, Bay State shifted $681,837 to its WMS adjustment in one of its supplemental filings, which it requests to recover over a 3 year period. Exh. CMA/JTG-1 (6/30/13 Update), p. 5; Exh. CMA/JTG-2 6/30/13 Update, Schedule JTG-6, p. 9.

In billing the associate companies, including Bay State, under the provisions of the Cost Allocation Manual, NCSC first directly charges costs to a particular operating company which benefits from the costs, whenever possible. The costs that are not directly charged are then allocated among the affiliates using one of several different allocation bases in effect. Between 2008 and 2012, the amount of costs directly charged to Bay State from NCSC increased $7.6 million, or 33%. During the 2012 test year, the direct charges increased by 8.26%. Exhibit AG-DR-1, p.7.

The indirect costs that are allocated to Bay State from NCSC using various allocation factors escalated by an even higher percentage during the same 5 year period. In fact, from 2008 to 2012, the indirect charges that were allocated to Bay State increased by an astronomical 98%.

During the 2012 test year alone, the indirect charges to Bay State increased by 7.95%. This is during a period of record low inflation. The table below presents the total indirect costs from NCSC to all associate companies and the indirect costs from NCSC to Bay State for each year, 2008 through 2012. The table also shows that the percentage of indirect costs allocated to Bay State as compared to the totality of the NCSC indirect costs being allocated increased from 8.62% in 2008 to 10.60% in 2009. By 2012, the total portion of indirect costs going to Bay State was 10.82%.

| | 2008 | 2009 | 2010 | 2011 | 2012 |
|---|---|---|---|---|---|
| 1. Indirect Costs to Associate Companies ($) | 77,597,835 | 99,430,359 | 105,629,146 | 116,010,572 | 122,321,391 |
| 2. % Change | | 28.14% | 6.23% | 9.83% | 5.44% |
| 3. Total Indirect Costs to Bay State ($) | 6,685,835 | 10,537,403 | 10,714,300 | 12,258,308 | 13,232,489 |
| 4. % Change | | 57.61% | 1.68% | 14.41% | 7.95% |
| 5. % of Bay State to Total (L. 4 / L.1) | 8.62% | 10.60% | 10.14% | 10.57% | 10.82% |

Exhibit AG-DR-1, p. 8.

NCSC's controller, Susan Taylor, agreed that the dollar amounts presented in the above tables are accurate, as well as the percentage changes to the amounts billed from NCSC to Bay State presented in the tables. Tr. Vol. IX, pp.890-892.

#### *b) The Company Has Not Demonstrated Any Reasonable Level of Effort Towards Bringing NCSC Cost Escalations Under Control*

The corporate culture at NiSource and NCSC appears to be a culture of excess without any meaningful attempt to control the costs that are ultimately direct charged or allocated to the various operating entities that receive services from NCSC. As an example, NiSource acquired a new corporate jet, a Cessna Model 680 Sovereign, within the last year. This is in addition to the existing corporate jet that NiSource already leases, which is a Hawker 800 XP. Tr. Vol. I, p. 41. As evidenced above, both the costs incurred by NCSC, as well as the costs charged to Bay State from NCSC, continue to grow exponentially. While Bay State removed many costs that were allocated from NCSC in its normalization adjustment as being inappropriate for inclusion in rates, it is very telling that NCSC incurs these costs to begin with and demonstrative of the corporate culture at NCSC.  For example, the Company initially removed $465,572 of the charges from NCSC to Bay State for charges from outside vendors.  It removed an additional $25,214 in its September 9, 2013 update filing for additional costs that should not be charged to ratepayers.  Exh. CMA/JTG-7, Workpaper JTG-2 9/3/13 Update, p. 23.  The $465,572 was the amount allocated to Bay State for charges "deemed non-recoverable based on Department precedent and policy or which CMA is not seeking recovery from its customers."  They include costs for promotional services, entertainment, donations, sporting events, and other costs that are inappropriate to pass on to Bay State's ratepayers.  The $465,572 removed from the charges to Bay State was just a portion of the total amount incurred by NCSC of $3,550,047.  Exhibit AG-14-12, Attachment AG-14-12, p. 2.  Again, while these costs were appropriately removed, it is indicative of a corporate culture of excessive spending on costs that are not directly related to the provision of services to the customers of the regulated operations.

Similarly, despite the astronomical increases in charges to Bay State from NCSC, the Company has failed to demonstrate that NCSC has taken meaningful efforts to control the costs it incurs and ultimately charges and allocates to Bay State.  Information Request AG-23-1 asked the Company to provide, in part, "any and all studies, analyses, reports and memorandum prepared by or for the Company or its parent which examine opportunities for cost efficiencies within the Company prepared in the last 5 years."  The only cost savings identified in the response specific to charges from NCSC pertained to a cost reduction for legal services provided through NCSC which occurred several years before the start of the test year, and most of which were in place by 2009. No additional cost reductions or cost containment measures were identified for NCSC in the response. Exh. AG-DR-1, pp. 24-25; Exh. AG-23-1.

In rebuttal to the AGO's position that the Company has not demonstrated that cost-containment measures have been implemented as it pertains to O&M expenses charged to Bay State from NCSC, Ms. Taylor indicates that each function within NCSC "…developed and implemented cost containment and/or process improvement initiatives" that she governs the cost level of in her capacity as Controller. Exh. CMA/SMT-1 Rebuttal, p. 9. Despite this assertion, no such contention or information was provided when asked for during the discovery process in this case. Exh. AG-23-1 and attachments. In her rebuttal testimony, Ms. Taylor identifies various activities undertaken by some of the NCSC functions, such as IT working with IBM to lower telecommunication rates, Treasury "taking advantage of downward trends in interest rates" for debt issuances, Corporate insurance using mutual insurance carriers and the accounts payable function automating more invoices and reducing the number of manual checks. Exh. CMA/SMT-1 Rebuttal, pp. 9-11. However, the actions identified on pages 9 through 11 of Ms. Taylor's rebuttal testimony are clearly not reflective of extraordinary efforts being taken by NCSC to aggressively control its costs and its charges to Bay State. Rather, the descriptions are normal actions that any company should be taking as normal course. In fact, Ms. Taylor did not even quantify any of the purported "cost containment and/or process improvement initiatives" until the final days of the hearing in this case, which was provided in response to RR DPU-16. However, RR DPU-16 provided no information, support, or workpapers for the purported "IT and Treasury cost savings" identified in the response, nor did it identify the costs incurred in achieving these purported savings. Clearly, even if some individual cost reductions in certain aspects of work performed by some of NCSC functional departments has occurred, they did not come even close to controlling the costs charged to Bay State from NCSC given the significant increases in those charges occurring each year.

### *c) Bay State's Adjustments to Normalize Charges from NCSC Are Riddled with Errors*

The adjustment made by Bay State to normalize the test year charges from NCSC was riddled with numerous errors. In fact, the NCSC normalization adjustment has been revised numerous times by Bay State in various attempts to correct the errors.[26] The number of revisions and the number of individual amounts that were revised in the workpapers were extensive and troubling.

As mentioned previously, the amount recorded in O&M expense on Bay State's books during the 2012 test year for charges from NCSC was $38,730,911. Exh. AG-DR-1, p. 9; Exh. AG-1-89. In its first attempt to normalize the test year charges from NCSC, Bay State calculated "Normalized Ongoing NCSC Costs" to be included in adjusted test year O&M expenses of $37,900,754. Exh. CMA/JTG-2, Schedule JTG-6, p. 9. In its June 30, 2013 update, the amount was revised to $37,169,659. Exh. CMA/JTG-2 6/30/13 Update, Schedule JTG-6, p. 9. A side-by-side comparison of these two versions of Exh. CMA/JTG-2, Schedule JTG-6, page 9, shows that the amounts on the following lines of the calculation were revised in the June 30th version: 2a – Transfers – related to WMS - O&M cost deferral; 15 – payroll annualization; 16 – incentive compensation; 17 – payroll taxes; 21 – PEF – Adjust for Gross NCSC/Pension/OPEB Charged to Capital; and 23 – Inflation Adjustment. Thus, the June 30th update not only shifted a portion of the O&M expenses to the WMS adjustment, but also corrected several errors in the calculation of the payroll and incentive adjustment as well as the PEF adjustment.

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[26] This section provides further evidence that the updates should be rejected. *See* Section VI, B.

In Exhibit AG-14-1, Attachment AG-14-1, dated July 17, 2013, the Company again revised the "Normalized Ongoing NCSC Costs" from the $37,900,754 contained in the June 30th version to $36,966,338. A side-by-side comparison of Exh. AG-14-1, Attachment AG-14-1 at "Exh. CMA/JTG-8(REV), WP JTG-2, p.15" to the June 30th update shows the amounts for each for the following items were revised: PEF Transfers included in Line 3 for EP&S; Payroll Annualization; Incentive Compensation; Payroll Taxes; PEF-Reverse PEF transfers recorded in 2012 – net of EP&S related PEF transfers; PEF – Gross NCSC Pension/OPEB Costs Charged; PEF – Adjusted for Gross NCSC Pension/OPEB Charged to Capital; and Inflation Adjustment. Additionally, another adjustment was added for "New NCSC Allocation Bases effective 1/1/13", which reduced the expenses charged to Bay State by $50,000.

With its September 3, 2013 Update, Bay State presented yet another version of its NCSC normalization adjustment, revising the "Normalized NCSC Costs" yet again to $39,924,841. In the September 3rd version, provided by Bay State as Exh. CMA/JTG-2, 9/3/13 Update, Schedule JTG-6, page 9, when compared to the version provided on July 7th in Exh. AG-14-1, revisions were made to the following lines in the adjustment: Net EP&S Corporate Services Included in O&M Expenses; Other One-Time Costs; PEF – Reverse PEF transfers recorded in 2012 – net of EP&S related PEF transfers; PEF Carrying Costs for NCSC Pension/OPEB; PEF – Gross NCSC Pension/OPEB costs charged; PEF – Adjust for Gross NCSC Pension/OPEB Charged to Capital; and Inflation Adjustment. In various responses, Bay State indicated that the numerous changes that were made in the September 3, 2013 update filing to the pension and PBOP amounts contained in the NCSC Adjustments workpapers was due to the information not being properly accumulated and inserted into the original workpapers correctly, which impacted numerous amounts contained in the workpapers supporting the adjustment to normalize NCSC costs. Exh.

AG-DR-Surrebuttal-1, pp.2-3; Exhibits AG-32-3, AG-32-4, AG-32-5, AG-32-6 andAG-32-7. The September 3, 2013 Update filing also removed an additional $17,397 of employee expenses for items such as sporting events and investor meetings, and costs associated with political, investor and other activities that should not be included in the revenue requirements that Bay State failed to previously remove. Ex. AG-DR-Surrebuttal-1, pp.3-4.

During the hearings, Bay State witness Jeffery Gore testified that he had been very confident that the June 30th Update amounts was accurate, but that he "enlisted the controller of the service company to help review and analyze the service company information." Mr. Gore also testified on October 15, 2013 that he was "very confident" that the service company adjustment in the September 3, 2013 update was an accurate reflection of the company's ongoing service company level of expenses. Tr. Vol. VIII, pp. 849-850

Unfortunately, the very next day after Mr. Gore testified that he was "very confident" the amount was accurate, yet another correction had to be made to the calculation of the Normalized Ongoing NCSC Costs by Bay State. The October 16, 2013 Update provided yet another version of the NCSC normalization adjustment to correct for an error in the inflation number, resulting in the final version of the "Normalized Ongoing NCSC Costs" being $36,926,530. Thus, the amount of Bay State's proposed normalized ongoing NCSC costs went from $37,900,754 in the first version provided by Bay State with its original April 16, 2013 filing to $36,926,530 by its fifth version provided with the October 16, 2013 filing, a reduction of $974,224. Of the $975,224 reduction to the normalized NCSC costs presented by Bay State, $681,837 was not removed from the amounts requested for recovery from ratepayers. Rather, it was shifted from the NCSC normalization adjustment to the WMS costs that Bay State is seeking recovery of in this case. The WMS costs are addressed above in this Brief.

Thus, in reviewing and analyzing the costs charged from NCSC to Bay State, the parties, and the Department, have been working with a moving target as a result of the many errors and incorrect inputs made by Bay State in its normalization calculations. Given the high level of costs charged to Bay State from NCSC, and the astronomical increases in those costs in recent years, the amount of errors and corrections made by Bay State in this area is both disappointing and alarming. The Department should find that these rampant errors weaken the credibility of the Company's witnesses in considering the weight to be given to the Company's evidence, as well as in considering whether the lack of care given to testimony and submissions to this tribunal are indicative of its subpar management.

#### *d) Projected 2014 Wage Increases for NCSC Employees are Not Known and Should be Removed*

The revised NCSC normalization adjustment includes an adjustment to increase recorded test year charges from NCSC by $718,719 for a payroll annualization adjustment. The $718,719 increase included: $124,199 for the for the annualization of the test year wage increase granted in June 2012; $293,011 for the effective 2.90% salary and wage increase that was granted in June 2013; and $301,509 for a projected 2.90% salary and wage increase to be granted in 2014. The 2014 wage increase of 2.90% is based on a projected 2.50% increase for the NCSC non-exempt employees and 3.0% for the NCSC exempt employees weighted based on the ratio of the number of NCSC exempt and non-exempt employees. Exh. AG-DR-1, pp.12-13. The payroll annualization adjustment remained at $718,719 in the last version of the NCSC normalization adjustment provided by Bay State. Exh. CMA/JTG-2 10/16/13 Update, Sch. JTG-6, p. 9, line 15.

The $301,509 that is included for a projected 2014 salary increase to NCSC employees must be rejected. The amount is not known and measurable and does not meet the Department's clear criteria for inclusion. There is no ambiguity with regards to the Department's criteria for inclusion of post-test year salary and wage increases. Specifically, the Departments recent order in Bay State's last rate case, D.P.U. 12-25, issued November 1, 2012, on pages 151-152, states as follows:

> To recognize an adjustment for increase in non-union wages that takes place prior to the issuance of an Order, a company must demonstrate that such increases are known and measure and also reasonable. See D.P.U. 08-35, pp. 81-82, 87; D.P.U. 92-250, p. 35; D.P.U. 1270/1414, p. 14. To recognize an adjustment for an increase in non-union wages that occurs post-Order, a company must demonstrate that: (1) there is an express commitment by management to grant the increase; (2) there is an historical correlation between union and non-union raises; and (3) the non-union increase is reasonable. D.P.U. 96-50 (Phase I) p. 42; D.P.U. 95-40, p. 21; D.P.U. 1270/1414, p.t 14. In addition, only non-union salary increases that are scheduled to become effective no later than the midpoint of the first twelve months after the date of the Order may be included in rates.

D.P.U. 85-266-A/85-271-A, p. 107.

In the same Order, at page 156, the Department rejected the Company's proposed non-union payroll increases for 2013, indicating that the increases constituted a post-Order increase and there was insufficient proof of management's commitment to grant the increases. Bay State has again failed to provide any proof of management's commitment to grant that projected 2014 salary and wage increase to NCSC employees. In fact, Bay State witness Kimberly K. Cartell specifically addresses the 2014 pay increase:

> The express written commitment is not included with this initial filing because, although the planned 2014 merit increase would occur shortly after the new rates in this case take effect, the date of that increase is more than a year in the future. It is not possible for NiSource management to commit to increases for CMA employees and NCSC employees who provide services to CMA without committing to a 2014 merit increase on an enterprise-wide basis. It is premature for this type of commitment to be made given the

> extended time period that exists between this filing and the date of the 2014 merit increase.

Exh. CMA/KKC-1, p. 26, line 20.

Given Ms. Cartell's testimony, it is clear that the Company has failed to provide any explicit written commitment signed by an authoritative company representative indicating that the NCSC non-exempt employees will receive a 2.50% increase and the NCSC exempt employees will receive a 3.0% increase during 2014. Thus, the adjustment to "Normalize Ongoing NCSC Costs" should be reduced by $301,509 to remove the projected post-Order increase from the adjusted test year. Similarly, the payroll tax expense included in Bay State's NCSC normalization adjustment should be reduced by $21,498 to remove the impact of the post-Order salary and wage increase from payroll taxes. Exh. AG-DR-1, pp. 15.

#### *e) Costs Charged from NCSC for Prior Rate Case Expense Should be Removed.*

Both the unadjusted and the adjusted test year charges from NCSC to Bay State include amounts paid to John E. Skirtich LLC and David R Mouser LLC for their assistance in the prior rate case. During the test year, NCSC paid $184,102 to John E Skirtich LLC, $87,518 of which was charged to Bay State. Exh. AG-14-20, Attachment AG-14-20, p.1. During the test year NCSC also paid $100,373.50 to David R Mouser LLC, $39,761 of which was charged to Bay State. Exh. AG-28-3. In rebuttal testimony, Company witness Gore indicates that the charges in the test year for Mr. Skirtich and Mr. Mouser represent "normal, legitimate and ongoing costs of NCSC in providing regulatory support to the NGD companies, including CMA." Exhibit CMA/JTG-Rebuttal-1, p.19. He also contends that "their time/billings are directly assigned to the NGD company benefitting from the service, and where multiple companies benefit, their time is allocated." Exh. CMA/JTG-Rebuttal-1, p. 17. However, it is clear from the description and the support provided by Bay State for Mr. Skirtich and Mr. Mouser's services that the majority of the work they performed during the test year that was charged to Bay State was for their assistance in the prior rate case, D.P.U. 12-25. While it may be "normal" for NCSC to use the services of these two gentlemen in assisting with rate cases, and they may have an ongoing charges from these gentlemen due to the frequency of filings in various jurisdictions, the costs in the test year that were charged to Bay State are largely for the assistance in the prior rate case. In years in which Bay State is not in for a rate case, presumably their services would focus on other NGD companies and be charged to other entities instead of Bay State. Thus, the amount included in the test year, during which these individuals assisted in the prior rate case, would not be reflective of a normal, on-going level of charges to Bay State. Rather, they are reflective of work performed during the period Bay State was in for a rate case and are specific to the prior rate case. Thus, test year charges from NCSC to Bay State should be reduced by $87,518 and $39,761 ($127,279 collectively) to remove these prior rate case expenses. Bay State's back door method of including expenses associated with the prior rate case in the adjusted test year expenses must be rejected. *Fitchburg Gas and Electric Light Company*, D.P.U. 11-01/D.P.U. 11-02, p. 259 ("Based on a review of the record, we find that the Company has failed to demonstrate that work performed from June 2009 through August 2009 for rate cases with a 2008 test year was either relevant or useful to the instant rate case filings"); D.P.U. 11-01/D.P.U. 11-02, pp. 264-265 ("rate case expense is limited to outside services procured for the preparation and presentation of a petition to increase rates under G.L. c. 164, § 94 and 220 C.M.R. §§ 5.00 et seq.").

Exhibit AG-24-12 provides ample evidence that the services provided by John E Skirtich, LLC during the 2012 test year that were charged to Bay State were predominately for support in the prior rate case. Exhibit AG-24-12 describes the services provided by Mr. Skirtich during the test year as follows:

> The services provided by Mr. Skirtich include expert testimony in rate proceedings before state regulatory commissions, assisting other witnesses (both in-house and contracted professionals) in the preparation and support of various issues in rate proceedings before state regulatory commissions, developing models for special studies to be used in rate proceedings, conducting research on regulatory matters before state commissions, preparing and supporting, as well as developing and conducting regulatory training programs for NCSC personnel, on Cost of Service/Revenue requirements, Allocated Cost of Service Studies, and Lead Lag studies. The depth of his knowledge of CMA's books and records, along with his experience and expertise in relation to the regulatory precedent and procedures in Massachusetts, makes Mr. Skirtich a valuable resource in preparing NGD's annual regulatory and financial planning process for CMA along with its periodic updates focusing on CMA. Special studies/requests of NCSC regulatory management and CMA management are prepared by Mr. Skirtich.
>
> These services accrue both short and long term benefits for CMA rate payers. Most recently Mr. Skirtich trained internal personnel on the preparation of the lead-lag study, which was supported by Mr. Gore in DPU-12-25 and Mr. Elliott in CMAs' current case in DPU-13-75. NCSC has developed an in-house capability to limit the need for outside consultants in jurisdictional rate cases to the benefit of customers. Similarly, Mr. Skirtich was instrumental in developing the Allocated Cost of Service Study supported by Mr. Balmert in both the 2012 and 2013 rate case, again reducing costs to customers.

Exhibit AG-24-12, Attachment AG-24-12(B), consisted of a status report from Mr. Skirtich for projects performed for NCSC in 2012. The projects on the attachment identified as specific to Bay State (abbreviated as CMA in the attachment) included: 1) "assistance in the preparation and train on new concepts such as rate year rate base as they impact the financial plan"; and 2) Rate case support consisting of planning, Cost of Service support and review, rate base development, ACOS Study support, reviewing testimony, assistance on data requests, and assistance on Compliance filing related to the ACOS study. Exhibit AG-24-12, Attachment AG-24-12(C) included the 2013 Work Plan/Project Schedule for Mr. Skirtich that was approved by the NSCSC Regulatory Strategy and Support management. Included in the 2013 work plan specific to Bay State is the assistance in the "preparation and adjudication of 2013 general rate case filing." Specific tasks identified for the general rate case assistance includes: 1) reviewing lead lag study results with Ron Gibbons and Brian Elliot; 2) assisting in preparation of the ACOS study with Mark Balmert and training of Kim Regrut; 3) assisting in the preparation and filing of information requests related to the lead lag study and the ACOS study; and 4) assisting in other issues as requested. Clearly, the evidence and support provided by Bay State shows that the test year charges from John E. Skirtich LLC were predominately for assistance in D.P.U. 12-25.

Similarly, the vast majority of the services provided by David R. Mouser LLC that were charged to Bay State during the 2012 test year were predominately for his assistance in D.P.U. 12-25. A review of the invoices from David R Mouser LLC to NCSC during the test year that are provided in Exhibit AG-28-3, Attachment 28-3-(C), clearly demonstrate that the charges to Bay State, identified as "CMA" in the invoices, were for work on the prior rate case.

#### *f) Excessive Level of Normalized Test Year Charges from NCSC Should Not Be Inflated*

The fifth and final version of the NCSC normalization adjustment presented by the Company in this case included $848,129 for the inflation of the adjusted test year charges from NCSC to Bay State. Exh. CMA/JTG-2 10/16/13 Update, Schedule JTG-6, p. 9, line 24. The Department should disallow the inflation of the adjusted test year charges from NCSC, reducing the adjusted test year expenses by $848,129. While the Department has allowed some costs to be inflated in the past, it should control the costs charged from NCSC and incent NCSC to control the costs being passed on to Bay State. Those costs should not be permitted to continue to escalate unchecked.

As demonstrated in this brief, the charges from NCSC to Bay State continue to increase significantly. In fact, the total amount of direct costs charged from NCSC to Bay State increased from $22.7 million in 2008 to over $30.3 million in the 2012 test year, an increase of 33% over a four-year period. The indirect costs allocated to Bay State from NCSC increase from approximately $6.7 million in 2008 to over $13.2 million in the 2012 test year, an increase of 98% in a four-year period. Exh. AG-DR-1, p.23. The majority of these costs direct charged and allocated to Bay State from NCSC remain in the Administrative and General Accounts on Bay State's books. Dr. David Dismukes demonstrates that the Administrative and General ("A&G") expenses on a per customer basis for Bay State are 82% higher than the average for the peer group used in his analysis, 47% higher than the average for other Massachusetts gas utilities, and 118% higher than the average for other NiSource Gas Distribution companies. Exhibit AG-23-1, pp. 23-24; Exhibit AG-DD-1, pp.82 - 84. The amount by which Bay State's A&G expenses exceeds its peers is staggering.

Given the enormous increases in the charges from NCSC to Bay State, coupled with the comparison of the A&G expenses incurred by Bay State (which includes the charges from NCSC) to its peers, the $848,129 increase in the adjusted test year charges from NCSC for inflation should be disallowed as an incentive for NCSC and Bay State to control these costs. Additionally, the Department should to take into consideration the numerous errors and revisions made by Bay State to its NCSC normalization adjustment in this case in evaluating whether or not Bay State's inflation of the NCSC charges is warranted. Exh. AG-DR-Surrebuttal-1, p.5.

Overall, the AGO recommends that the "normalized ongoing NCSC Costs" contained in Bay State's original, April 16, 2013 filing of $37,900,754 be reduced by $2,274,328 to: 1) reflect the various Company corrections and revisions made to the original adjustment; 2) remove the post-order 2014 NCSC salary and wage increase and associated payroll taxes; 3) remove the rate case expenses for D.P.U. 12-25 from the normalized costs; and 4) remove the NCSC inflation adjustment. Exhibit AG-DR-3 9/25/13 Update.

#### 4. THE DEPARTMENT SHOULD REJECT THE COMPANY'S REQUEST TO RECOVER THE COSTS OF PRIVATE AND CHARTER AIRCRAFT FROM CUSTOMERS

Bay State has again included the costs for its executive private and chartered airplanes in the cost of service in this case. *See* Exh. AG-1-54. However, this time it has decided to double down on its luxuries by leasing yet another jet at an additional cost to customers. If NiSource's shareholders feel the necessity to provide management with such executive perks that is their purgative. However, the shareholders should be burdened with such extravagances, and not Bay State Gas Company's customers.

The Company has included some $180,559 for leasing and chartering executive jets for its officers. *Id*. This includes $146,253 for leases which represents a 190 percent increase over the lease expense in the previous year. *Compare* Exh. AG-1-54 and D.P.U. 12-25, p. 121 (2012) ("The Company has included some $114,371 for leasing and chartering executive jets for its executives. *Id*. This amount includes $50,364 to lease a Hawker 800XP executive jet.") Regardless of how comfortable the officers feel they need to be in their travels, certainly the number of officers has not doubled since 2011, the test year in the last case.

A utility is under an obligation to provide least cost service to its customers. *See* D.T.E. 05-27, pp. 46, 49 (2005); *Massachusetts-American Water Company*, D.P.U. 95-118, p. 47;

*Incentive Regulation*, D.P.U. 94-158, p. 3 (1995). The failure, on a utility's part, to make economic, least cost choices in providing service would not be tolerated in the competitive market place and should not be tolerated in determining the cost of service used to establish the rates for monopoly services. The Company has clearly gone overboard with these executive jet perks. The Department should shield customers from these extravagant costs. Therefore, the Department should deny the inclusion of the Company's leased and chartered jets in the cost of service and reduce the revenue requirement accordingly.

#### 5. RATE CASE EXPENSE

The Department should disallow the Company's request to recover its expenses for Aon Hewitt's labor and benefits analyses, and should limit the recovery of expenses for legal fees associated with this filing.

The Company has an affirmative duty to contain rate case expenses. *See Fitchburg Gas & Electric Light Company*, D.T.E. 98-51, p. 57 (1998). The Department has repeatedly expressed concern with the high level of rate case expenses. *New England Gas Company*, D.P.U. 08-35, p. 129 (2009); *Fitchburg Gas and Electric Light Company*, D.P.U. 07-71, p. 90 (2008); *Boston Gas Company*, D.P.U. 93-60, p. 145 (1993); *Bay State Gas Company*, D.P.U. 92-111, p. 208 (1992); *Massachusetts Electric Company*, D.P.U. 92-78, p. 58 (1992). The Department has stated that it will "scrutinize the overall level of rate case expense and may require shareholders to shoulder a portion of the expense." D.P.U. 08-35, p. 135. If a company elects to secure outside services for rate case expense, it must engage in a "structured, objective competitive bidding process for these services." *Boston Gas Company*, D.T.E. 03-40, p. 153 (2003). A company must provide an adequate justification and showing, with contemporaneous documentation, that their choice of outside services is both reasonable and cost-effective when seeking recovery of rate-case expenses. *Id*., p. 153; *see also Fitchburg Gas & Electric Light Company,* D.T.E. 02-24/25, p. 192, *citing* D.T.E. 98-51, p. 61 (wherein the Department warned Fitchburg that failure to provide adequate justification for not using the competitive bidding process would result in disallowance of rate case expense); D.P.U. 07-71, pp. 139-140 (Department adjusted ROE downward as a result of Company's failure to conduct a competitive bidding process for any outside services related to the rate case proceeding). The Department has explained that a company need not go with the lowest bidder; however, "[i]f a company engages an outside consultant or legal counsel who is not the lowest bidder in the competitive bidding process, the company must provide adequate justification of its decision to do so." D.T.E. 03-40, p. 153. Companies are "on notice that they are at risk of non-recovery of rate case expense expenses should they fail to sustain their burden to demonstrate cost containment associated with the selection and retention of outside service providers." *Western Massachusetts Electric Company*, D.P.U. 10-70, pp. 158-159 (2011) (internal quotations omitted).

***a) Legal Services***

The Department should limit the expense that the Company can recover for legal services. Although the Company conducted a competitive bidding process for the retention of legal counsel in this rate case, it did not select the lowest cost provider. Exh. DPU-1-4. **#BEGINCONFIDENTIAL#** [redacted]**.**[27] **#ENDCONFIDENTIAL#** Accordingly the Department should cap the Company's recovery of legal fees, from ratepayers, at the amount equal to the lowest true bid.

As the Department has made clear on numerous occasions, the need to contain rate case expense, "must be accorded a high priority in the review of bids received for rate case work."

[27] **#[BEGINCONFIDENTIAL]#**[redacted]**.[ENDCONFIDENTIAL]**

*Fitchburg Gas and Electric Light Company*, D.P.U. 11-01, p. 247 (2011), *citing New England Gas Company*, D.P.U. 10-114, p. 222 (2011); D.T.E. 03-40, p. 153. "While the Department will not substitute its judgment for that of a petitioner in determining which consultant may be best suited to serve petitioner's interests, in seeking recovery of rate case expenses, companies must demonstrate that their choice of consultants is both reasonable and cost-effective." D.P.U. 11-01, p. 247 (internal citations omitted). This burden is heightened when the Company does not select the lowest bidder. *Id.*, pp. 247-248. Here, the Company fails to meet this heightened burden.

Pursuant to the Department's mandate that companies utilize a competitive bid process, the Company sought bids from seven different law firms. Exh. DPU-19-1. It received bids from five. *Id.* Utilizing a weighted scoring system, the bids were scored by Kenneth W. Christman, Assistant General Counsel at NCSC. Exh. DPU 19-6. Keegan Werlin, LLP, which was awarded the contract, had the highest evaluative score, Exh. DPU-1-3 (a) Att. (Redacted), pp. 2-3, and was not the lowest bidder, Exh. DPU-1-4. This selection is both unreasonable and not cost-effective.

(1) The Company's Selection of Keegan Werlin For Legal Services Was Unreasonable.

The Company's request for proposals ("RFP") was conducted primarily by Mr. Christman.[28] He drafted the RFP issued by the Company on November 9, 2012 in consultation with Mr. Bryant, Mr. Richard Cencini, and Ms. Susan Kullberg. Exh. DPU-1-2(a) Att. (Redacted). Along with technical assistance from Ms. Kullberg, Mr. Christman also scored the bids. Exh. DPU-19-6. While this process was almost entirely developed and evaluated by Mr.

[28] This section is an evaluation of the Company's selection process. It is not intended to endorse or malign any particular firm.

Christman, he did not sponsor any testimony regarding the selection methodology. While his selection memorandum was entered into evidence, Exh. DPU-1-3(b) Att. (Redacted), this was improper as it was neither attested to nor sworn to by Mr. Christman. *See* 220 C.M.R. § 1.10(1) ("All unsworn statements appearing in the record shall not be considered evidence on which a decision may be based"). Additionally, Mr. Christman was not presented as a witness available for cross-examination. Instead, Mr. Bryant sponsored the responses containing information known only by Mr. Christman. *See e.g.*, Exhs. DPU-1-3; DPU-1-4; DPU-19-6. However, Mr. Bryant has no personal knowledge of the scoring or evaluation of the submitted bids. Tr. Vol. IX (Public), pp. 929-931. Accordingly, Mr. Christman's evaluative scoresheets, Exh. DPU-1-3(a) Att. (Redacted), pp. 2-3, and selection memorandum, Exh. DPU-1-3(b) Att. (Redacted), should be given no weight by the Department. *See generally Commonwealth v. Cintron*, 435 Mass. 509, 521 (2001) (witness may not testify to a matter unless sufficient evidence is introduced to support a finding that the witness has personal knowledge of the matter); *Malchanoff v. Truehart*, 354 Mass. 121-122 (1968) (same); *Commonwealth v. Walcott*, 28 Mass. App. Ct. 200, 207 (1990) (same). Therefore, the Company has failed to meet its burden regarding the reasonableness of its RFP evaluative process. *See generally NSTAR Electric Company*, D.P.U. 06-82-A, p. 49 (2010) (moving party must prove its case by a preponderance of the evidence); *see also Bay State Gas Company*, D.P.U. 09-30, p. 228 (2009) (Company has the burden of demonstrating that its selection of consultants was prudent and appropriate).

However, even if the Department chooses to give weight to Mr. Christman's unattested exhibits, the selection of Keegan Werlin was objectively unreasonable due to anomalies in the scoring of its bid.[29] The RFP issued for legal services contained seven criteria that would be used to evaluate submitted proposals. Exh. DPU-19-6. Each criteria was then assigned a

[29] A full comparative analysis of all of the submitted bids is outside the scope of this brief.

numerical value of between one and ten (with ten being the highest possible score). *Id.* This raw score was then weighted according to the criteria set out in the RFP. *Id.* Keegan Werlin received a raw score of 69 out of a possible 70. Exh. DPU-1-3(a) Att. (Redacted), p. 3. To achieve this score, Keegan Werlin was given perfect scores for six of the seven criteria. *Id.*

The lone category for which Keegan Werlin did not receive a perfect score was for "Hourly Rate, Other Billing Determinants." *Id.* Keegan Werlin's score of nine for that category was still the second highest score among respondents, trailing only Rich May, P.C.. *Id.* However, **#BEGINCONFIDENTIAL#** [redacted] **#ENDCONFIDENTIAL#.** This scoring disparity is objectively unreasonable.

Unfortunately, the "Hourly Rate, Other Billing Determinants" category does not represent the only RFP scoring irregularity. For the category of "Firm Staff/Resources Depth," the Company stated:

> In this case [ ], each of the bidders has proposed to use a team consisting of at least four experienced lawyers. As a result, we conclude that each bidder has the resources available to perform the requested services, including the ability to handle rate case hearings while simultaneously performing other required tasks.

Exh. DPU-1-3(b) Att. (Redacted), p. 6. By its own admission, each bidder had the requisite resources to litigate this case. Yet, Keegan Werlin was given the only perfect score of ten. Exh. DPU-1-3(a) Att. (Redacted), p. 3. **#BEGINCONFIDENTIAL#** [redacted]

[redacted] #ENDCONFIDENTIAL# While Keegan Werlin received a score of ten, the other firm was given a nine. Exh. DPU-1-3(a) Att. (Redacted), p. 3. **#BEGINCONFIDENTIAL#** [redacted] **#ENDCONFIDENTIAL#** Yet, they too received a less than perfect score of nine. Exh. DPU-1-3(a) Att. (Redacted), p. 3. Thus, the scoring for this category was also facially irrational and unreasonable.

These anomalies are not indicative of a thorough analysis of the submitted bids. *See* D.P.U. 09-30, p. 228 (2009) (best evidence to demonstrate reasonableness of consultant selection is "documentation of a well-analyzed decision making process"). The above scoring irregularities, coupled with the lack of an appropriate witness to testify to the scoring system employed, mandates that the Department limit recovery of legal fees to the lowest submitted true bid, as described below.

(2) The Company's choice for legal services was not cost-effective.

**#BEGIN CONFIDENTIAL#** [redacted]

[redacted] #END CONFIDENTIAL#

According to the Company, one of the reasons that Keegan Werlin was selected for legal services was because its experience with NiSource and CMA “should significantly reduce the overall cost of the case by eliminating the need for ramping up on the part of the new service provider.”  Exh. DPU-1-3(b) Att. (Redacted), p. 11; *see also* Exh. DPU-1-4 (Company states that Keegan Werlin’s experience “should avoid the need for an extensive ‘ramp-up’ and lower the number of hours required to prepare and present the case.”).  **#BEGINCONFIDENTIAL#.**

[redacted]

**#ENDCONFIDENTIAL#**  Therefore, the Department should cap the recovery of legal fees from ratepayers, at the lowest true bid amount of **#BEGINCONFIDENTIAL#** [redacted] **#ENDCONFIDENTIAL#** *See e.g., Fitchburg Gas and Electric Light Company*, D.P.U. 11-01/11-02, p. 251 (2011) ("[W]here comparably qualified lower priced bidder is available to do the work, the additional cost of the higher bidder must be borne by shareholders and not ratepayers"). In the alternative, the Department could set the reasonable bid amount at the median as calculated from the true bids, listed above, and disallow any recovery above this amount.

#### *b) Labor and Benefits Analyses*

Where the company retains a consultant or a legal services provider without a competitive bidding process, the Department will not allow the company to recover that expense unless the company's failure to engage in competitive bidding was justified by "the most unusual of circumstances." D.P.U. 10-70, p. 158 ("In all but the most unusual of circumstances, it is reasonable to expect that a gas or electric company can comply with the competitive bidding requirement"); *National* Grid, D.P.U. 10-55, p. 341 (2010) (the same). Accordingly, the "Department fully expects that competitive bidding for outside rate case services, including legal services, will be the norm." D.P.U. 10-70, p. 158. The competitive bidding process "provides the Department with an objective method to determine whether the services could have been adequately provided at lower costs." D.P.U. 10-70, p. 158, citing D.P.U. 09-30, p. 230 and D.T.E. 03-40, p. 151. Moreover, engaging in a competitive bidding process "keeps even a consultant with a stellar past performance from taking the relationship with a company for granted." *Id.*

The Company has an ongoing relationship with the consulting firm of Aon Hewitt, who provides NiSource with advice and guidance in "setting competitive salary ranges and evaluating and recommending changes to employee benefit plans." Exh. CMA/KKC-1, p. 4; Exh. DPU-1-1, p. 2. Based on this existing relationship, NiSource selected Aon Hewitt to assist with the Labor and Benefits Analyses accompanying the Company's filing. Exh. DPU-1-1, p.2. The Company did not solicit bids from other consultants for this work. *Id.* This practice was previously authorized by the Department, who concluded:

> that it is unlikely that an alternative service provider, less familiar with the Company and the foundational data upon which the ultimate opinions would be based, could duplicate these specialized services for a lower cost, especially when considering the expense associated with issuing separate RFPs for these services.

*Bay State Gas Company*, D.P.U. 12-25, p. 192 (2012).

However, the Department's inquiry does not end there. "The Department has directed companies to provide all invoices for outside services that detail the number of hours billed, the billing rate, and the specific nature of services performed." *Fitchburg Gas and Electric Light Company*, D.T.E. 02-24/25, p. 193 (2002). Failure to comply with this mandate can result in disallowance of that portion of the proposed rate case expense. *Id.*

In its filing, the Company estimated a rate case expense, as it relates to "Labor and Benefits Analyses," of $75,000, for Aon Hewitt's services. Exh. CMA/JTG-1, sch. JTG-6, p. 2. This is the same estimated amount provided by the Company in its last rate case filing, despite the fact that the total amount billed in that case, by Aon Hewitt, was only $19,080. *See* D.P.U. 12-25, p. 192. As of October 1, 2013, Aon Hewitt has submitted two invoices, in the present case, totaling $15,3697.47.[30] Exh. DPU-19-9(B) Att. (Redacted), pp. 61-62. This amount should

[30] Charges are broken out by "Work Detail" and "Expense Detail." Exh. DPU-19(B) (Att.) (Redacted), pp. 61-62.

be disallowed in its entirety due to its lack of detail. The two invoices provided list the "Work Detail" as "2013 CMA Rate Case," and the "Expense Detail" as "Miscellaneous Expenses." *Id.* These generic descriptions fail to provide the necessary detail for the Department to determine if the expenses were reasonable, appropriate, and prudently incurred and were proportional to the work performed. D.P.U. 10-55, p. 323 (2010). The invoices submitted by Aon Hewitt to the Company are entirely devoid of any information that could justify the amount included. *Compare* Exh. DPU 19-9 Att. (redacted), pp. 61-62 *with* Exh. DPU 19-9(B) Att. (Redacted), pp. 1-54 (Keegan Werlin invoices detailing date, attorney, task, activity, hours, rate and amount). Therefore, the full amount of rate case expense for Labor and Benefits Analyses should be denied.

## H. Capital Structure and Rate of Return

### 1. INTRODUCTION.

The overall cost of capital is determined for Bay State by "weighting" the individually determined cost rates for the Company's equity capital and debt capital by the relative percentages of equity and debt in its capital structure. Exh. CMA/VVR-3. This overall, composite weighted average cost of capital ("WACC") is then applied to the Company's test year rate base to determine the return on rate base component of the cost of service used to determine base rates in this proceeding. Exh. CMA/JTG-2, Sch. JTG-1 and JTG-2.

The cost of capital rate that the Department ultimately uses to determine the cost of capital in rates must meet the standard for determining the allowed ROE is set forth in Hope and Bluefield. The allowed ROE should preserve the Companies' financial integrity, allow it to attract capital on reasonable terms, and be comparable to returns on investments of similar risk.

*See Federal Power Commission v. Hope Natural Gas Company*, 320 U.S. 591, 603-605 (1944) ("Hope"); *Bluefield Water Works v. West Virgini*, 262 U.S. 679, 692-693 (1923) ("Bluefield").

The AGO sponsored the testimony of Dr. J. Randall Woolridge regarding the appropriate rate of return for Bay State. Exh. AG/JRW-1-16. Dr. Woolridge has adjusted the Company's proposed capital structure to more accurately reflect the capitalizations of gas distribution companies and Bay State's parent, NiSource, ultimately recommending that a 50 percent debt and 50 percent common equity capital structure be used. *Id*., pp. 15-16. Dr. Woolridge estimates an equity cost rate for Bay State by applying the Discounted Cash Flow Model ("DCF") and the Capital Asset Pricing Model ("CAPM") to a group of gas distribution companies ("Gas Proxy Group"). *Id*., pp. 13-14. Dr. Woolridge analyses resulted in an appropriate cost of equity capital rate in the range of 7.3 to 8.75 percent. *Id*., p. 50. The Company sponsored the testimony of Mr. Vincent V. Rea regarding the Company's proposed capital structure and equity cost rate. Exh. CMA/VVR-1. Mr. Rea estimates an equity cost rate of 11.45.percent for Bay State. *Id*., p. 3. He has used the DCF, CAPM, Risk Premium ("RP"), and Comparable Earnings ("CE") approaches to estimate the cost of equity capital for the Company. *Id*., p. 4. Mr. Rea applies these models to three separate proxy groups of companies; a gas utility group, a combination utility group, and a non-regulated, non-utility group. *Id*. The Company recommends an overall rate of return of 8.85 percent. *Id*., p. 3.

Mr. Rea's analysis should be rejected by the Department, since he has used an inappropriate: (1) capital structure for Bay State; (2) combination, all utility and non-utility proxy groups to estimate an equity cost rate for the gas distribution operations of Bay State; (3) expected DCF growth rate, and in particular Mr. Rea's elimination of low DCF equity cost rates, as well as the use of the projected growth rates of Wall Street analysts to measure expected DCF growth; (4) base interest rates in the CAPM and RPM approaches; (5) measurement and magnitude of the equity risk premium used in CAPM and RPM approaches; (6) CE equity cost rate approach; and (7) adjustment for size and flotation costs.

### 2. INTEREST RATES AND AUTHORIZED ROES FOR GAS DISTRIBUTION COMPANIES

Differences in opinions regarding the level of interest rates and capital costs are a significant issue in this proceeding. Bay State's Mr. Rea has maintained that the historically low interest rates are abnormal and he seems to speculate that big increases in interest rates are on the horizon. Exh. CMA/VVR-Rebuttal-1, pp. 16-21. He supports this supposition by reference to the aggressive monetary policy actions of the Federal Reserve and his own presumption that the Fed would begin to taper its Quantitative Easing III ("QE3") program in September of 2013. *Id.* pp. 16-17. However, despite Mr. Rea's forecasts of changes in Federal Reserve monetary policy, the Federal Reserve in its September meeting announced that QE3 would continue and that "highly accommodative" monetary policy would continue to be required to meet economic targets on unemployment and inflation. Exh. AG – JRW- Surrebuttal-1, p. 3.

The fact is that the Commission should not be setting authorized returns for utilities based on one witness' speculation about monetary policy and interest rates. With respect to speculation about monetary policy and interest rates, Dr. Woolridge summarized the issue very succinctly under cross- examination:

> But in the end, bond investors are big, sophisticated financial institutions. Right now, they price in the ten-year Treasury is at 2.68 percent, something like that. Why is that? Because they take into account economic activity, monetary policy, fiscal policy in determining that's what the rate is. If the rate was supposed to jump up 50 basis points in the next three months, obviously they wouldn't be buying bonds at 2.68 percent.

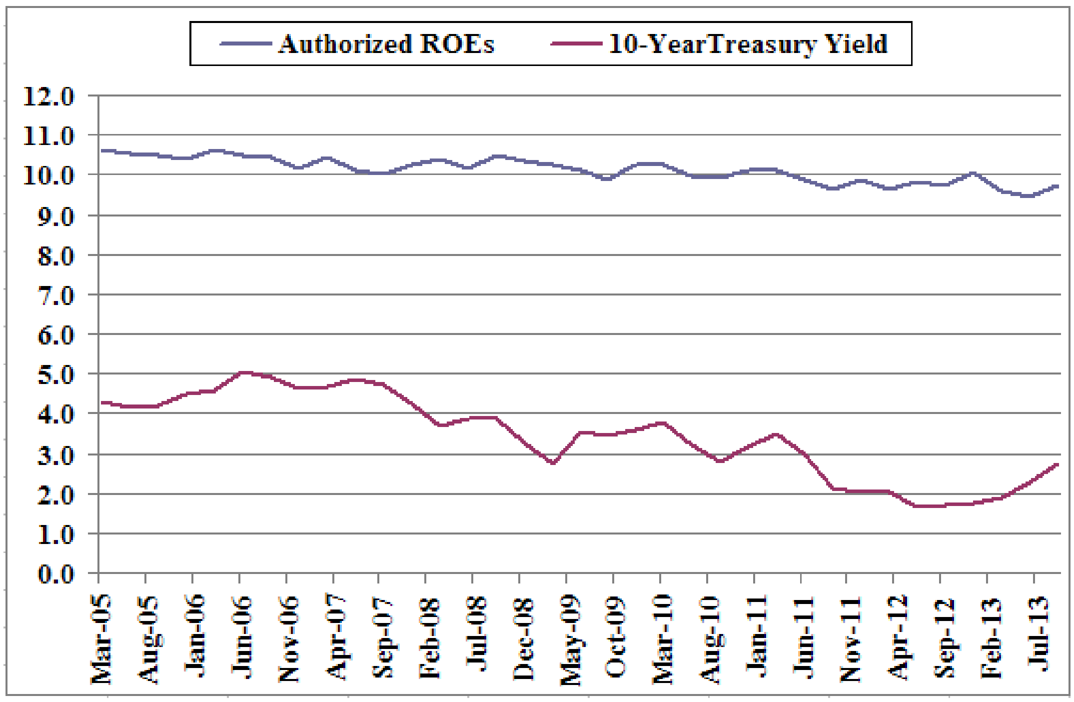
Tr. Vol. X, pp. 1038-1039.

The AG believes that it is important to put the current level of interest rates in perspective. A review of Exhibit JRW-2 shows that prior to the record low levels of interest rates in the last two years, the last time the ten-year Treasury rate was as low as 2.68% was 1957! In other words, despite the rise in interest rates over the past year, interest rates are still at levels from sixty years ago. *Id*.

In his rebuttal testimony, Mr. Rea does point to the higher interest rates over the past year to support a higher ROE for Bay State. Exh. CMA/VVR-Rebuttal-1, pp. 16-21. Dr. Woolridge addressed this issue in his surrebuttal testimony and under cross examination. Exh. AG – JRW-Surrebuttal-1, pp. 4-8 and Tr. Vol. X, pp. 1035-1039. Dr. Woolridge acknowledged that interest rates, as indicated by ten-year Treasury rates, have increased by over 100 basis points from mid-year 2012 to the present. However, he shows that this does not necessarily mean that equity capital costs for gas companies have increased dramatically over that time. *Id*. To demonstrate this point, Dr. Woolridge evaluated the relationship between interest rates and the authorized ROEs for gas distribution companies. Specifically, he studied the relationship between ten-year Treasury yields on a quarterly basis from 2005-2013. *Id*. Figure 1 provides the data graphically, and shows that authorized ROEs for gas distribution companies gradually declined from the 10.5% range in 2005 to 9.5% as of the second quarter of 2013. *Id*. The yields on ten-year Treasury bonds were in the 4.0% to 5.0% range in the 2005-2006 time-frame, decreased to 1.50% in mid-2012, and since increased to 2.70%. *Id*. Dr. Woolridge notes that in looking at the relationship between the two, it is significant that when ten-year Treasury yields declined to below 3.0% in mid-2011 and into 2012, authorized ROEs for gas distribution companies did not decline in a lock-step fashion in interest rates. *Id*. In fact, Ten-year Treasury yields declined from about 3.5% in the first quarter of 2011 to 1.5% in the second quarter of 2012. *Id*.

However, while the authorized ROEs for gas companies did dip to below 10.0% in the second quarter of 2011, and have pretty much remained in the 9.5% to 10.0% range. *Id*. Dr. Woolridge notes that the key point of the analysis is that authorized ROEs for gas companies never declined to reflect the extremely low interest rates in 2012. *Id*. Therefore, simply because interest rates have increased over the past year does not necessarily mean that equity cost rates for gas companies have increased in a similar magnitude.

**Figure 1**
**Authorized ROEs for Gas Distribution Companies and Ten-Year Treasury Yields**
**2010-2013**




### 3. THE COMPANY'S RECOMMENDATION OF 11.45% IS "OFF THE CHART"

Mr. Rea makes numerous arguments that Dr. Woolridge's 8.75 percent ROE recommendation for Bay State is inadequate and does not conform to *Hope* and *Bluefield* standards for a fair rate of return. Exh. CMA/VVR-Rebuttal-1, pp. 6-9. To make his point, he presents a graph of the authorized ROEs for gas companies over the 2009-2013 time-period. *Id*., p.7.  This graph is presented in Figure 2.  In Figure 2, text boxes have been provided that show: (1) Dr. Woolridge's 8.75 percent recommendation; (2) the 2012 and 2013 average authorized ROEs for gas companies; and (3) Mr. Rea's 11.45% ROE recommendation.  Two things stand out in the graph: (1) While Dr. Woolridge's recommendation is below the recent national average authorized ROE for gas companies, these average authorized ROEs have been declining in the last two years as a reflection of the low capital cost environment discussed by Dr. Woolridge; and (2) whereas Dr. Woolridge's 8.75 percent ROE recommendation is at the low end of the ROEs presented, Mr. Rea's 11.45 is so high, it does not even make the chart.  In other words, his recommendation is literally off the chart!

**Figure 2**

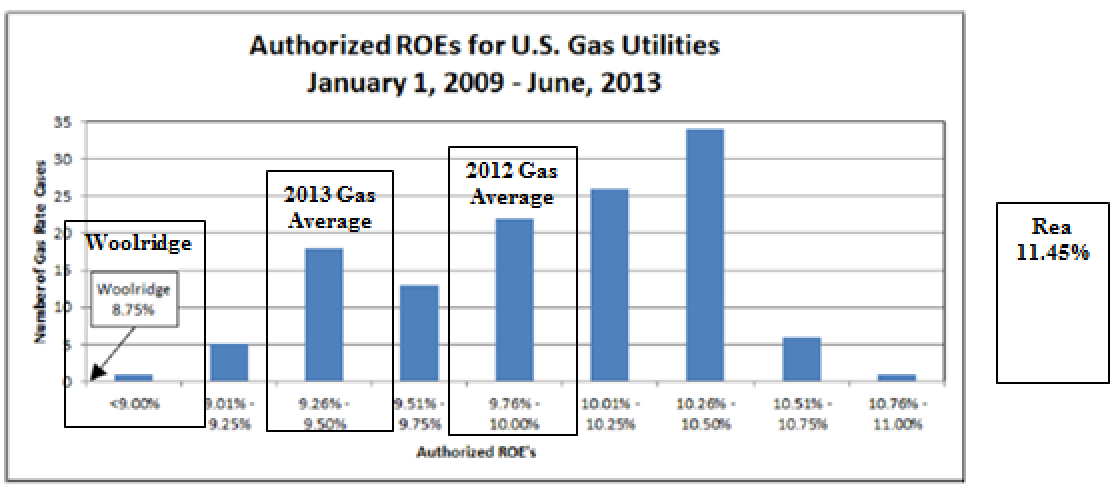



Exhibit CMA/VVR-Rebuttal-1, p. 7.  Text boxes have been added to show Woolridge ROE, 2012 and 2013 Gas Average ROEs, and Rea ROE.

### 4. Capital Structure.

Bay State is requesting a capital structure consisting of 46.32 percent long-term debt and 53.68 percent common equity.  Exh. CMA/VVR-6.  The Company has also proposed a long-term debt cost rate of 5.83.percent.  Exh. CMA/VVR-7.

Bay State's recommended capital structure includes much more common equity than the capital structure of Bay State's parent company, NiSource. *Compare* Exh. AG/JRW-5, pp. 1 and 2. NiSource's average common equity ratio over the past three years is 43.26 percent excluding short-term debt. *Id*., p. 15. Dr. Woolridge indicates that this is very significant because the bond ratings and debt costs of Bay State are directly tied to the bond ratings of NiSource. Exh. AG/JRW-1, p. 15. This is highlighted by an S&P report on NiSource and its subsidiaries, including Bay State:

> The stand-alone financial profiles of NiSource's utility subsidiaries are much stronger than the consolidated financial profile, where substantial acquisition-related debt is held. Nevertheless, we view the default risk as the same throughout the organization, due to the absence of regulatory mechanisms or other structural barriers that sufficiently restrict subsidiary cash flow to the holding company.

Attachment AG-1-1, p. 114-48, Global Ratings Portal - Ratings Direct, Standard & Poor's, NiSource Inc., February 29, 2012.

Dr. Woolridge's Gas Proxy Group provides another indication of the appropriate capitalization of gas companies. Dr. Woolridge shows that the Gas Proxy Group has a median common equity ratio of 48.5 percent. Exh. AG/JRW-1, p. 15. Another indicator is the average capitalization ratio approved by regulators in gas rate cases. Under cross examination, Mr. Rea stated that according to the Regulatory Research Associates, the average common equity ratio approved in gas rate cases in 2013 is 50.31 percent. Tr. Vol. IV, p. 417. Thus, the typical common equity ratio for gas distribution companies is significantly lower than that of Bay State on a standalone basis.

To recognize that Bay State's ultimate source of capital, its bond ratings, and its debt cost rates are all from NiSource, as well as the capitalization ratios of the Gas Proxy Group and other gas companies, Dr. Woolridge used a capital structure with 50% long-term debt and 50%

common equity. Exh. AG/JRW-1, pp. 15-16. The Attorney General recommends that the Department use these capital structure ratios to determine the Bay State's overall weighted cost of capital in this case.

### 5. COST OF DEBT.

The Department should recognize that Bay State failed to refinance its outstanding notes with NiSource Finance Corp. that would have saved the Company more than $5.1 million per year in interest expense. *See Bay State Gas Company*, D.P.U. 12-25, p. 389 (2012). The Company claims that NiSource Finance Corp. actually issued bonds to the market to fund the notes it has outstanding with Bay State. Tr. pp. 454-455. However, the Company could not point to any bond issues to support this bald statement. Indeed, the Company plainly admitted that NiSource didn't in fact issue any bonds as a result of the Bay State notes. Exh. AG.8-12 ("Considering that CMA's financing requirements represent a small percentage of NiSource's overall financing activities, no NFC debt instruments were issued as a direct result of debt instruments issued by CMA.") Therefore, there is no evidence to support the claim that monies were somehow tied up with outstanding bonds that have make whole provisions as the Company claims. Indeed, NiSource is most likely financing the Bay State notes entirely with short-term debt, extracting huge profits from Bay State customers given the difference between the 5.83 percent long-term debt rate that it is charging customers and the 1.07% interest rate it pays for short-term debt. Exh. AG-1-6, Att. C. The Department should recognize and find imprudent the Company's failure to reduce its interest costs given its ability to refinance its notes that has outstanding with NiSource Finance Corp, and adjust the cost of service accordingly.

### 6. RETURN ON COMMON EQUITY.

#### ***a) Proxy Group.***

Bay State does not issue common stock that is traded in the market place. Exh. CMA/VVR-1, p. 3. Its parent corporation, NiSource holds all of its outstanding stock. *Id*. Since it is the cost of capital from the market perspective that it is important to the cost of equity determination, it is appropriate to evaluate the cost of capital based on a group of utilities of similar investment risk profile. *Bluefield Water Works and Improvement Company v. Public Service Commission of West Virginia*, 262 U.S. 679 (1923) and *Federal Power Commission v. Hope Natural Gas Company*, 320 U.S. 591 (1942).

The Department has accepted the use of a comparison group of companies for evaluation of a cost of equity analysis when a distribution company does not have common stock that is publicly traded. *See New England Gas Company*, D.P.U. 08-35, pp. 176-177 (2008); *Fitchburg Gas and Electric Light Company*, D.T.E. 99-118, pp. 80-82 (2001); *Massachusetts Electric Company*, D.P.U. 92-78, pp. 95-96 (1992). The Department has also generally rejected the results of non-regulated groups. *Berkshire Gas Company*, D.T.E. 01-56, p. 116 (2002); *Boston Gas Company*, D.P.U. 96-50, Phase I p. 132 (1996); *Cambridge Electric Light Company,* D.P.U. 92-250, pp. 160-161 (1993); *Bay State Gas Company*, D.P.U. 92-111, pp. 280-281 (1992); *Berkshire Gas Company*, D.P.U. 905, pp. 48-49 (1982).

Dr. Woolridge has evaluated the return requirements of investors on the common stock of the companies in his proxy group of publicly-held gas distribution companies ("Gas Proxy Group"). Exh. AG/JRW-1, pp. 13-14 and Exh. AG/JRW-4. The companies in the group include AGL Resources, Atmos Energy Corporation, Laclede Group, Northwest Natural Gas Company, Piedmont Natural Gas Company, South Jersey Industries, Southwest Gas, and WGL Holdings. *Id*.

Summary financial statistics for the proxy group are listed on page 1 of Exhibit AG/JRW-4. The median operating revenues and net plant for the Gas Proxy Group are $1,570.7 million and $3,037.0 million, respectively. *Id.* The group receives 71 percent of revenues from regulated gas operations, has an 'A' bond rating from Standard & Poor's, a current common equity ratio of 48.5.percent, and a current earned return on common equity of 10.1 percent. *Id*.

Mr. Rea has used four proxy groups to estimate an equity cost rate for Bay State. Exh. CMA/VVR-1, pp. 20-40. These include: (1) Gas LDC Group - a group of nine gas distribution companies; (2) Combination Utility Group – a group of nine combination electric and gas companies; (3) an All Utilities group – all utilities in the Gas LDC and Combination Utility groups; and (4) a Non-Regulated Group – a group of 30 unregulated companies. *Id*.

Mr. Rea's gas utility group includes the same companies as Dr. Woolridge's Gas Proxy Group, with the exception of New Jersey Resources. *Compare* Exh. AG/JRW-1, p. 13 and Exh. CMA/VVR-1, p. 25. Dr. Woolridge has excluded New Jersey Resources, because the company only receives 29 percent of its revenues from regulated gas operations. Exh. AG/JRW-1, p. 53. Nonetheless, even if one were to include New Jersey Resources in the proxy group, this one company would not impact the results. Tr., Vol. X, p. 1050. On the other hand, Dr. Woolridge does not concur with Mr. Rea's use of his Combination Utility and Non-Regulated groups. Exh. AG/JRW-1, pp. 53-54. The companies in Mr. Rea's Combination Utility group are listed as combination electric and gas companies by AUS Utilities Reports and as electric utility companies by Value Line and they receive 69 percent of revenues from regulated electric operations and only 23 percent of their revenues from regulated gas operations. *Id*. Dr. Woolridge demonstrated that these companies are not gas distribution companies and they have a higher risk profile than gas distribution companies as indicated by a lower average bond rating than gas distribution companies. *Id*. Hence, due to the higher risk profile of the Combination Utility group, it is not appropriate an appropriate proxy group to estimate an equity cost rate for Bay State. *Id*.

Dr. Woolridge also demonstrated that Mr. Rea's group of 30 non-utility companies is not an appropriate proxy group for Bay State. Exh. AG/JRW-1, pp. 54-5. This group, which includes such companies as AT&T, Costco, McKesson, PepsiCo, Pfizer, and Verizon, have lines of business that are (1) vastly different from the gas distribution business; and (2) do not operate in a highly regulated environment. *Id*. In addition, as Dr. Woolridge testified, the upward bias in the Earnings per Share ("EPS") growth rate forecasts of Wall Street analysts is particularly severe for non-regulated companies, and therefore the DCF equity cost rate estimates for this group are particularly overstated. *Id*. Therefore, the non-regulated group is not an appropriate proxy for Bay State, and the equity cost rate results for this group should be rejected by the Department. *Berkshire Gas Company*, D.T.E. 01-56, p. 116 (2002); *Boston Gas Company*, D.P.U. 96-50, Phase I p. 132 (1996); *Cambridge Electric Light Company,* D.P.U. 92-250, pp. 160-161 (1993); *Bay State Gas Company*, D.P.U. 92-111, pp. 280-281 (1992); *Berkshire Gas Company*, D.P.U. 905, pp. 48-49 (1982).

### ***b) Discounted Cash Flow Analysis Results.***

Dr. Woolridge estimates DCF equity cost rates of 8.75 percent for the Gas Proxy Group of gas utility companies. Exh. AG/JRW-1, pp. 38-39. Table 1 below provides the dividend yield and growth rate inputs for these DCF results.

**Table 1**
**Summary of Dr. Woolridge's DCF Results**

| | Dividend Yield | 1 + ½ Growth Adjustment | DCF Growth Rate | Equity Cost Rate |
|---|---|---|---|---|
| **Gas Proxy Group** | **3.65%** | **1.0250** | **5.00%** | **8.75%** |

With respect to the dividend yield, Dr. Woolridge makes a ½ year adjustment to the spot dividend yield. *Id*., pp. 31-32. As Dr. Woolridge explains, a ½ year growth adjustment is appropriate because companies change their dividend payouts at different times during the year. *Id*.

To estimate the DCF growth rate, Dr. Woolridge has reviewed both historical and projected growth rate measures, and has evaluated growth in dividends ("DPS"), book value ("BVPS"), and earnings per share ("EPS"). *Id*., pp. 31-39. He has used the forecasted EPS growth rates of Wall Street analysts and the projected growth in EPS, DPS, and BVPS of Value Line in estimating a DCF equity cost rate. *Id*. Dr. Woolridge also provides extensive empirical evidence that demonstrates the long-term EPS growth rates of Wall Street analysts are overly optimistic and upwardly-biased. Exh. AG/JRW-1, Appendix B.[31] Dr. Woolridge also demonstrates that the estimated long-term EPS growth rates of Value Line are overstated. *Id*. Ultimately, Dr. Woolridge considered a wide range of historical and forecast data regarding the DCF growth rates for the Gas Proxy Group. His recommendation was as follows:

> Page 6 of Exhibit JRW-10 shows the summary DCF growth rate indicators for the proxy group. The historical growth rate figures for the Gas Proxy Group suggest a baseline growth rate of 4.3% for these companies. The projected and sustainable growth rates from Value Line are 4.3% and 4.2% for the group. Analysts projected EPS growth is 5.0%. The average of sustainable and projected EPS growth rate indicators is 4.5%. Giving more weight to the projected growth rate figures, and in recognition of the recent increase in interest rates, I will be conservative and use the 5.0% as the DCF growth rate for the Gas Proxy Group, thus yielding a conservatively high growth rate estimate for my DCF analysis.

[31] Dr. Woolridge also provided articles from the *Wall Street Journal* and *Business Week* which discuss this bias. Exh. JRW-13.

Exh. AG/JRW-1, p. 39. Therefore, the Department should find that a 5.0 percent growth rate is appropriate for the DCF analysis in this case.

Mr. Rea develops an equity cost rate by applying a DCF model to his three proxy groups. Exh. CMA/VVR-1, pp. 60-110; and Exh. CMA/VVR-7 - CMA/VVR-12. For the DCF growth rate, Mr. Rea uses four measures of projected EPS growth – the projected EPS growth of Wall Street analysts as compiled by Thompson FN First Call and Zack's, Value Line's projected EPS projected growth rate, a Value Line retention growth measure that is computed as the sum of internal ("br") and external ("sv") growth, and a Value Line historical growth rate measure. Exh. CMA/VVR-8, p. 1; Exh. CMA.VVR-9, p. 1; and Exh. CMA/VVR-10, p. 1. Mr. Rea makes two additional adjustments to his DCF result. He includes a leverage adjustment which adjusts his DCF results for the difference in the market value and book value capital structures of his proxy group companies. Exh. CMA/VVR-1, pp. 92-99 and Exh. CMA/VVR-12. He also makes a flotation cost adjustment to account for stock issuance costs. Exh. CMA/VVR-1, pp. 100-101. Mr. Rea's DCF results are summarized in Panel B of page 1 of Exhibit JRW-13. The average of the DCF results is 10.18 percent for the gas LDC group, 11.22 percent for the combination utility group, 10.71 percent for the all utilities group, and 12.06 percent for the non-utility group. *Id*.

Dr. Woolridge demonstrated that Mr. Rea's DCF equity cost rate must be rejected for five reasons: (1) the use of the combination utility, all utilities, and non-utility groups to estimate an equity cost rate for Bay State's regulated gas distribution business, (2) the excessive reliance on the EPS growth rate forecasts of Wall Street analysts and Value Line as a DCF growth rate; (3) the asymmetric classification and elimination of DCF results; (4) the leverage adjustment and (5) the flotation cost adjustment. *See* Exh. AG/JRW-1, pp. 56-66.

One primary error with Mr. Rea's DCF equity cost rate for his gas LDC group is his asymmetric elimination of DCF results. *Id*., pp. 57-8. In his DCF study, Mr. Rea has labeled equity cost rates below 7.35 percent as extreme outliers. Exh. CMA/VVR-1, pp. 85-92. Dr. Woolridge explains the impact the eliminations for Mr. Rea's gas group:

> These screens eliminate 8 of his DCF results. All of the eliminated DCF results are on the low end. By eliminating only low outliers and not also eliminating high outliers, Mr. Rea biases his DCF equity cost rate study and reports a higher DCF equity cost rate than the data indicate. As shown on Page 3 of Exhibit JRW-13, his average reported DCF equity cost rate for the gas utility group is 9.4% when he eliminates only low outliers. However, the mean and median DCF equity cost rates, including all observations, are both 8.8%. As such, Mr. Rea's data DCF suggests that Bay State's DCF equity cost rate should be about 8.8% and not 9.4%.

Exh. AG/JRW-1, p. 57. Thus, Mr. Rea's DCF analysis must be rejected for no other reason than the upward bias in his results caused by his asymmetrical elimination of outliers.

Another error in Mr. Rea's DCF analysis is his exclusive use of the forecasted EPS growth rates of Wall Street analysts and Value Line. In Appendix B attached to his testimony, Dr. Woolridge provides ample empirical evidence that demonstrates the long-term earnings growth rates of Wall Street analysts and Value Line are overly optimistic and upwardly-biased. Exh. AG/JRW-1, App. B. On this issue, Dr. Woolridge cites a recent study from McKinsey:

> Alas, a recently completed update of our work only reinforces this view—despite a series of rules and regulations, dating to the last decade, that were intended to improve the quality of the analysts' long-term earnings forecasts, restore investor confidence in them, and prevent conflicts of interest. For executives, many of whom go to great lengths to satisfy Wall Street's expectations in their financial reporting and long-term strategic moves, this is a cautionary tale worth remembering. This pattern confirms our earlier findings that analysts typically lag behind events in revising their forecasts to reflect new economic conditions. When economic growth accelerates, the size of the forecast error declines; when

> economic growth slows, it increases. So as economic growth cycles up and down, the actual earnings S&P 500 companies report occasionally coincide with the analysts' forecasts, as they did, for example, in 1988, from 1994 to 1997, and from 2003 to 2006. *Moreover, analysts have been persistently overoptimistic for the past 25 years, with estimates ranging from 10 to 12 percent a year, compared with actual earnings growth of 6 percent. Over this time frame, actual earnings growth surpassed forecasts in only two instances, both during the earnings recovery following a recession. On average, analysts' forecasts have been almost 100 percent too high.*

Marc H. Goedhart, Rishi Raj, and Abhishek Saxena, "Equity Analysts, Still Too Bullish," *McKinsey on Finance*, pp. 14-17 (Spring 2010) (emphasis added). Therefore, the Department must again reject Mr. Rea's DCF analysis because of the upward bias in this results caused by his over-reliance on these short-term EPS forecasts.

Dr. Woolridge also shows that Mr. Rea's historical growth rate analysis is flawed. Exh. AG/JRW-1, pp. 59-60, Exh. JRW-13, p.3. Specifically, Dr. Woolridge shows that Mr. Rea's computed five-year historic growth rates using Value Line data are greater than the five-year historic growth rates reported by Value Line. *Id.* pp. 59-60.

Dr. Woolridge also demonstrated that Mr. Rea's leverage and flotation cost adjustment are inappropriate. Exh. AG/JRW-1, pp. 60-64. Regarding the leverage adjustment, Mr. Rea claims that an upward adjustment is needed for his DCF results because (1) market values are greater than book values for utilities and (2) the overall rate of return is applied to a book value capitalization in the ratemaking process. Exh. CMA/VVR-1, pp. 92-99. Dr. Woolridge testified that this adjustment is unwarranted and illogical. Exh. AG/JRW-1, pp. 60-61. Furthermore, Dr. Woolridge indicates that Mr. Rea's leverage adjustment has been rejected by regulatory commissions, because it increases the ROEs for utilities that have high returns on common equity and decreases the ROEs for utilities that have low returns on common equity. *Id*.

The Department has rejected utility proposals for leverage adjustments. *See Bay State Gas Company*, D.P.U. 09-30, pp. 358-359 (2009); *Bay State Gas Company*, D.T.E. 05-27, p. 298 (2005); *Boston Gas Company*, D.T.E. 03-40, p. 357 (2003); *Berkshire Gas Company*, D.T.E. 01-56, p. 105 (2001); *Boston Edison Company*, D.P.U. 906, pp. 100-101 (1982); *Eastern Edison Company*, D.P.U. 837, p. 49 (1982). Similarly, the Department has frequently rejected the price-book analysis because it fails to recognize variables such as a company's geographic location, load factors, and customer make-up, which can affect price-book ratios. *Boston Edison Company*, D.P.U. 906, at 100-101. Additionally, the price-book analysis has been found to rely excessively on investor perceptions of the relationship between market and book prices in their investment decisions. *Eastern Edison Company*, D.P.U. 837, p. 49 (1982). The Company has not provided new evidence or arguments to change this well-established precedent. Therefore, the Department should again deny the Company's request for a leverage adjustment.

Dr. Woolridge also demonstrated that the flotation cost adjustment is unnecessary. *Id*., pp. 62-64. Indeed, Mr. Rea has not identified any current flotation costs for Bay State. *Id*. As a result, Dr. Woolridge indicates that there is no reason to compensate the Company with annual revenues in the form of a higher ROE to cover flotation cost that Bay State is not paying. *Id*.

In the past, the Department has consistently rejected the inclusion of flotation costs in the cost of service. *Berkshire Gas Company*, D.P.U. 90-121, p. 180 (1990); *Boston Gas Company*, D.P.U. 88-67 Phase I, pp. 193 (1988); *Western Massachusetts Electric Company*, D.P.U. 86-280-A, p. 112 (1987); *AT&T Communications of New England*, D.P.U. 85-137, p. 100 (1985). The Department has found that the use of a flotation cost adjustment to ROE is not appropriate because investors already take into account issuance costs in their decision to purchase the stock at a given price. *Id*.

Furthermore, utilities which are part of a holding company structure are considered not to have flotation costs and negligible issuance costs, because all stock is issued to the parent company of the holding company. *Massachusetts Electric Company*, D.P.U. 800, p. 51 (1982); *Western Massachusetts Electric Company*, D.P.U. 20279, p. 37 (1980); *Massachusetts Electric Company*, D.P.U. 19376, pp. 7-13 (1979). The Company has not provided new evidence or arguments to change this well-established precedent. Therefore, the Department should again deny the Company's request for an adjustment for flotation costs.

Therefore, the Department should reject the Company's proposed DCF analysis as set forth by Mr. Rea. Instead, the Department should rely on the DCF results and recommendations as presented by Dr. Woolridge that establish an 8.5 percent cost of equity capital for the Company.

#### ***c) Capital Asset Pricing Model Analysis Results.***

Dr. Woolridge estimates an equity cost rate of 7.3 percent for the Gas Proxy Group using the CAPM. Exh. AG/JRW-1, pp. 40-50. The CAPM requires an estimate of the risk-free interest rate, beta, and the market risk premium. *Id*. pp. 40-41. Table 5 below provides the risk-free, interest rate, beta, and market risk premium inputs for these CAPM results.

**Table 5**
**Summary of Dr. Woolridge's CAPM Results**

| | Risk-Free Rate | Beta | Equity Risk Premium | Equity Cost Rate |
|---|---|---|---|---|
| **Gas Proxy Group** | **4.0%** | **0.65** | **5.0%** | **7.4%** |

*Id*., p. 52.

The yield on 30-year Treasury bonds has been in the 2.6 percent to 4.0 percent range over the 2011-2013 time period. *Id*., p. 42. This yield is currently about 3.60%. *Id*. Given the recent range of yields, and the prospect of higher rates in the future, the use of a 4.0 percent interest rate provides a conservatively high estimate of the risk-free rate ("*Rf*") for the CAPM. *Id*.

Beta (ß) is a measure of the systematic risk of a stock. The market, usually approximated the S&P 500, has a beta of 1.0. *Id*. The beta of a stock with the same price movement as the market also has a beta of 1.0. *Id*. A stock whose price movement is greater than that of the market, such as a technology stock, is riskier than the market and has a beta greater than 1.0. *Id*. A stock with below average price movement, such as that of a regulated public utility, is less risky than the market and has a beta less than 1.0. *Id*. Estimating a stock's beta involves running a linear regression of an individual stock's return on the market return.

Dr. Woolridge used the betas for the eight companies in his proxy group of gas utility companies as provided in the *Value Line Investment Survey*. *Id*. The median beta for the companies in Gas Proxy Group is 0.65. Exh. AG/JRW-11, p. 3.

The major issue in using the CAPM is the measurement and the magnitude of the equity risk premium. *Id*. pp. 43-44. There are typically three procedures that can be used to estimate the market or equity risk premium–historical return analyses, surveys, and expected return models. *Id*., p. 44-47. Dr. Woolridge incorporated all three in his analysis.

To arrive at an equity risk premium, Dr. Woolridge initially reviewed the results of over thirty equity risk premium studies and surveys performed over the past decade. *Id*., p. 47. These are presented on page 5 of Exhibit JRW-11 and include the summary equity risk premium results of (1) the annual study of historical risk premiums as provided by Morningstar (formerly Ibbotson Associates); (2) ex ante equity risk premium studies commissioned by academics, consulting firms, (3) equity risk premium surveys of CFOs, analysts, companies financial forecasters, as well as academics; and (4) Building Block approaches to the equity risk premium. The median equity risk premium of these studies is 4.39 percent. Exh. JRW-11, p. 5.

Due to the recent impact of the financial crisis, Dr. Woolridge also observed the results of equity risk premium studies and surveys that were published after January 2, 2010. Exh. AG/JRW-1, pp. 47-8. These results are presented on page 6 of Exhibit JRW-11. The median for the equity risk premium studies published in the 2010-2013 time period was 4.51 percent. Dr. Woolridge concludes that much of the data indicates a market risk premium in the range of 4.0 percent to 6.0 percent. Dr. Woolridge uses the midpoint of this range, 5.0 percent, as the market risk premium in his CAPM. *Id*, p. 48. An equity risk premium of 5.0 percent is consistent with the following studies of equity risk premiums:

> (1) an equity risk premium in the 3.5-4.0 percent range employed by the leading management consulting firm in the world-McKinsey & Co.-for corporate valuation purposes;
>
> (2) an equity risk premium of 5.7 percent discovered in a 2013 survey of financial analysts, companies, and academics conducted by Pablo Fernandez. This survey included 6,000 responses;
>
> (3) the ex ante equity risk premium of 4.30% employed by CFOs as reported by John Graham and Campbell Harvey of Duke University from their survey of CFOs in June, 2013; and
>
> (4) the ex ante equity risk premium of 2.3% as forecasted by leading economists in the Federal Reserve Bank of Philadelphia's annual *Survey of Professional Forecasters* which was published February 13, 2013.

Exh. AG/JRW-1, p. 49. For all of the above reasons, the Department should use a market equity risk premium no higher than 5.0 percent in any CAPM analysis that it uses to determine the cost of equity capital for the Company. The result of Dr. Woolridge's CAPM analysis, incorporating the components discussed above, is a cost of equity capital estimate of 7.3 percent.

Mr. Rea applies the CAPM method to each of his proxy groups. Exh. CMA/VVR-1, pp. 111-132; Exh. CMA/VVR-13. For each group, he calculates a CAPM equity cost rate using (1) a prospective risk-free bond rate of 4.46 percent, and (2) a market risk premium of 7.45 percent. *Id*., pp. 2, 5, and 8. He uses the average leverage-adjusted beta for the gas LDC group (0.74), the combination utility group (0.83), and the non-utility group (0.71). *Id*. He also adds a size premium of 1.14 percent for the gas LDC group and the combination utility groups and -0.38 percent for the non-regulated group. *Id*., p. 8. Mr. Rea's CAPM results are summarized in Panel C of page 1 of Exhibit JRW-13.

There are several flaws with Mr. Rea's CAPM analysis that render it useless, including: (1) his use of the so-called empirical CAPM ("ECAPM"); (2) the magnitude of the risk-free interest rate of 4.46 percent; (3) the use of leverage-adjusted betas for the three groups; (4) the magnitude of the equity or market risk premium of 7.45 percent; (5) the inclusion of a size premium; and (6) the use of the combination utility and non-regulated groups. Exh. AG/JRW-1, pp. 65-75. Each of these flaws will be discussed below.

With respect to the ECAPM, as Dr. Woolridge testified, this is nothing more than an *ad hoc* version of the CAPM and has not been theoretically and empirically validated in refereed journals. *Id*., p. 66. *See New England Gas Company*, D.P.U. 08-35, p. 207 (2009) ("The Department has rejected the use of the traditional CAPM as a basis for determining a utility's cost of equity because of a number of limitations, including questionable assumptions that underlie the model.") In addition, Mr. Rea's application of the ECAPM is erroneous, since he used adjusted betas in the analysis, and these adjusted betas already address the empirical issues with the CAPM that Mr. Rea is attempting to correct by increasing the expected returns for low beta stocks and decreasing the returns for high beta stocks. *Id.*

There are also flaws with Mr. Rea's risk-free rate of interest of 4.46 percent. *Id*., pp. 66-7. Dr. Woolridge highlights the fact that this rate is above current market yields. As of August, 2013, the actual yield on 30-year Treasury bonds is 3.6 percent. *Id*.

Mr. Rea's use of leverage adjusted betas is also erroneous. *Id*. Whereas the average betas for Mr. Rea's gas LDC group, combination utility group, and non-regulated group are 0.66, 0.71, and 0.65, respectively, he employs betas of 0.74, 0.83, and 0.78 for these groups, after his adjustments. *Id*. Mr. Rea has adjusted the beta upwards for the book value/market value capitalization difference. *Id*. As Dr. Woolridge explains, Mr. Rea is making the same erroneous and illogical leverage adjustment to his betas that he made to his DCF results to reflect the difference between the market values and the book values of the companies in his proxy group. *Id*. *See also Bay State Gas Company*, D.P.U. 09-30, pp. 358-359 (2009); *Bay State Gas Company*, D.T.E. 05-27, p. 298 (2005); *Boston Gas Company*, D.T.E. 03-40, p. 357 (2003); *Berkshire Gas Company*, D.T.E. 01-56, p. 105 (2001); *Boston Edison Company*, D.P.U. 906, pp. 100-101 (1982); *Eastern Edison Company*, D.P.U. 837, p. 49 (1982).

Notwithstanding these issues, Dr. Woolridge indicates that the primary problem with Mr. Rea's CAPM analysis is the magnitude of the market or equity risk premium. *Id*., pp. 67-75. Mr. Rea develops a market risk premium of 7.45 percent which is computed as the average risk premium of: (1) the 1926-2011 historical risk premium results from the Ibbotson study of 6.60 percent and (2) a projected market risk premium of 8.29 percent, using an expected market return which is the average of: (a) *Value Line's* 3-5 year annual return projection and (b) a DCF expected market return using the S&P 500. Exh. CMA/VVR-1, pp. 115-116. As Dr. Woolridge testified, the primary error with Mr. Rea's equity risk premium is that both the Ibbotson historical returns and

Mr. Rea's projected market returns are poor measures of expected market risk premiums. Exh. AG/JRW-1, pp. 68-75.

With respect to Mr. Rea's historical risk premium of 6.60 percent, Dr. Woolridge explains the errors associated with computing an expected equity risk premium using historical stock and bond returns in Appendix D to his prefiled testimony. Exh. AG/JRW-1, Appendix B. He highlights that there is a myriad of empirical problems with this approach that result in historical market returns producing inflated estimates of expected risk premiums. *Id*. These errors include the U.S. stock market survivorship bias (the "Peso Problem"), the company survivorship bias (only successful companies survive), and unattainable return bias (the Ibbotson procedure presumes monthly portfolio rebalancing). *Id*.

Mr. Rea also computes an expected equity risk premium of 8.29 percent, using an expected market return of 12.80 percent, which is the average of: (a) *Value Line's* 3-5 year annual return projection of 12.80 percent and (b) a DCF expected market return using the S&P 500 of 12.70 percent. Exh. CMA/VVR-1, p. 115. Dr. Woolridge shows that the error in using *Value Line's* 3-5 year annual return projections is that these projections are consistently high relative to actual experienced returns and, as such, provide upwardly biased equity risk premiums. Exh. AG/JRW, pp. 69-70. He shows that over the 1984-2012 time period, the *Value Line's* 3-5 year annual return projection has been, on average, 5.5 percent above the actual 3-5 year return. *Id*. He attributes this error to a misstated dividend yield and the reluctance of investment analysts to project negative results for companies. *Id*., pp. 69-70.

Mr. Rea also estimated an expected market return of 12.70 percent by applying the DCF model to the S&P 500. Exh. CMA/VVR-1, p. 115. This approach uses a dividend yield of 2.30 percent and an expected DCF growth rate of 10.40.percent. *Id*. Dr. Woolridge testified that the primary error in Mr. Rea's approach is that the expected DCF growth rate is the projected 5-year EPS growth rate for the companies in the S&P 500 as reported by FactSet. Exh. AG/JRW-1, p. 71. Mr. Rea uses an expected S&P 500 growth rate of 10.40 percent which represents the forecasted 5-year EPS growth rates of Wall Street analysts. *Id*. In Appendix B, attached to his prefiled testimony, Dr. Woolridge provides the research that demonstrates that the EPS growth rate forecasts of Wall Street securities analysts are overly optimistic and upwardly biased. Exh. AG/JRW-1, App. B. Further, Dr. Woolridge shows that a long-term growth rate of 10.40 percent is inconsistent with historical economic and earnings growth in the U.S. *Id*. Dr. Woolridge performs a study of the growth in nominal GDP, S&P 500 stock price appreciation, and S&P 500 EPS and DPS growth since 1960. *Id*., p. 75. The results are provided Table 6.

**Table 6**
**GDP, S&P 500 Stock Price, EPS, and DPS Growth**
**1960-Present**

| | |
|---|---|
| **Nominal GDP** | **6.74%** |
| **S&P 500 Stock Price** | **6.35%** |
| **S&P 500 EPS** | **6.96%** |
| **S&P 500 DPS** | **5.39%** |
| **Average** | **6.36%** |

Exh. AG/JRW-1, p. 72. Dr. Woolridge's study shows that the historical long-run growth rates for GDP, S&P EPS, and S&P DPS are in the 5 percent to 7 percent range. By comparison to these historical standards, Mr. Rea's long-run growth rate projection of 10.40 percent is vastly overstated. *Id*., p, 72.

The link between long-term EPS, GDP growth and stock returns is fundamental to understanding the gross error in Mr. Rea's analysis. Dr. Woolridge cites a study by Brad Cornell, who finds that long-term EPS growth in the U.S. is directly related GDP growth, with GDP growth providing an upward limit on EPS growth. Exh. AG/JRW-1, p. 74. In addition, Cornell finds that long-term stock returns are determined by long-term earnings growth. He concludes with the following observations:

> The long-run performance of equity investments is fundamentally linked to growth in earnings. Earnings growth, in turn, depends on growth in real GDP. This article demonstrates that both theoretical research and empirical research in development economics suggest relatively strict limits on future growth. In particular, real GDP growth in excess of 3 percent in the long run is highly unlikely in the developed world. In light of ongoing dilution in earnings per share, this finding implies that investors should anticipate real returns on U.S. common stocks to average no more than about 4–5 percent in real terms.

Bradford Cornell, "Economic Growth and Equity Investing," *Financial Analysts Journal* (January- February, 2010), p. 63.

Mr. Rea's projected EPS growth rate of 10.4 percent is even more outrageous given the projections of even slower growth for the U.S. economy. Dr. Woolridge cites forecasts of annual GDP growth from the *Survey of Professional Forecasters* (4.8% annual growth rate), the Energy Information Administration (4.5% annual growth rate), and the Congressional Budget Office (4.6% annual growth rate). *Id.* p. 73. These figures suggest GDP growth in the range of 4.0% to 5.0% is more appropriate today for the U.S. economy. This shows that Mr. Rea's long-term growth EPS growth rate of 10.40 percent is even more inflated. *Id*. Dr. Woolridge summarizes his assessment of Mr. Rea's analysis as follows:

> Investment banks, consulting firms, and CFOs use the equity risk premium concept every day in making financing, investment, and valuation decisions. On this issue, the opinions of CFOs and financial forecasters are especially relevant. CFOs deal with capital markets on an ongoing basis since they must continually assess and evaluate capital costs for their companies. They are well aware of the historical stock and bond return studies of Ibbotson. The CFOs in the June 2013 CFO Magazine – Duke University Survey of over almost 350 CFOs shows an expected return on the S&P 500 of 6.7% over the next ten years. In addition, the financial forecasters in the February 2013 Federal Reserve Bank of Philadelphia survey expect an annual market return of 6.15% over the next ten years. As such,

> with a more realistic equity or market risk premium, the appropriate equity cost rate for a public utility should be in the 8.0% to 9.0% range and not in the 11.0% to 12.0% range.

Exh. AG/JRW-1, p. 74-5. As described above, each of these flaws in Mr. Rea's analysis renders his CAPM results and recommendation useless for determining the cost of equity.

Mr. Rea also includes a size adjustment in his CAPM approach to account for the size of the companies in his groups. Exh. CMA/VVR-1, pp. 128-9. This adjustment is based on the historical stock market returns studies as performed by Morningstar (formerly Ibbotson Associates). *Id*. As Dr. Woolridge demonstrates, there are numerous empirical errors in using historical market returns to compute risk premiums, which result in Ibbotson's size premiums being poor measures for risk adjustment to account for the size of the Company. Exh. AG/JRW-1, pp. 75-8. Dr. Woolridge also highlights the research of Professor Annie Wong who tested for a size premium in utilities and concluded that, unlike industrial stocks, utility stocks do not exhibit a significant size premium. *Id*. Professor Wong indicates that there are several reasons why such a size premium would not be attributable to utilities. These reasons include the regulation and monitoring of utilities by state and federal regulatory agencies and the uniform accounting and reporting standards for public utilities. *Id*. Finally, Dr. Woolridge also highlights the research of Ching-Chih Lu (2009) who estimated the size premium over the long-run. *Id*. Lu attributes the size premium found in various studies to the rebalancing presumption used in calculating returns and finds that the size premium disappears within two years. *Id*.

The Department has a longstanding precedent rejecting size premiums. D.P.U. 09-30, p. 362; *New England Gas Company*, D.P.U. 08-35, pp. 216-217 (2009). As the Department has found:

> The Morningstar study includes companies that are non-price regulated such that their risk profiles may not be comparable with the

> risk profiles of the companies in the comparison group and of the Company. More specifically, the companies included in the Morningstar study have betas greater than one, unlike the betas of the companies in the comparison group that are less than or at most equal to one.
> Therefore, using company size only to place the companies of the comparison group within the sixth decile and NEGC within the tenth decile may not provide a sufficient basis for comparability.

*Id*.

Bay State has not provided any new evidence or argument that should cause the Department to change its well-established precedent. Therefore, the Department should deny the Company's proposal to adjust its cost of equity for a size premium. *Id.*

#### *d) Risk Premium Approach.*

Mr. Rea estimates equity cost rates for his three groups ranging from of 10.14 percent to 10.28.percent using the Risk Premium approach. Exh. CMA/VVR-1, pp. 133-44; Exh. CMA/VVR-14. As a base yield, he uses a prospective yield on 'Aaa' rated corporate bonds of (4.97 percent) and adds 71 basis points to arrive at an A3 utility bond yield (5.68 percent). *Id*. His overall risk premium of 4.60 percent for the gas LDC group is the average of a total market return risk premium of 4.88 percent and a public utility index risk premium of 4.31 percent. *Id*. The total market return risk premium of 4.88 percent uses the average of the historical relationship between stock and bond returns over the 1926-2011 time period (5.40.percent) and the prospective stock market return of 12.75.percent developed for his CAPM approach. *Id*. He then adjusts the prospective market risk premium by the levered beta of the gas LDC group. *Id*. The public utility risk premium is developed as the difference between the returns on the S&P utility index and A-rated Moody's bonds over the 1926-2011 time period. *Id*. RP studies are also performed for the combination utility and non-regulated groups. *Id*., p. 128.

There are several serious flaws in Mr. Rea's Risk Premium analysis. These errors include: (1) the projected base yield of 5.68 percent for A3-rated public utility bonds; (2) the risk premium of 4.60 percent for the gas LDC group which is based on historical and projected market returns; and (3) the use of the combination utility and non-regulated groups. Exh. AG/JRW-1, pp. 78-81. Each of these flaws will be discussed below.

First, as Dr. Woolridge testifies, Mr. Rea's base yield of 5.68 percent is overstated.' *Id*., p. 79. The current yield on long-term A-rated public utility bonds is 4.54 percent. *Id*. and Exh. AG/JRW-3, p. 1. In addition, Dr. Woolridge testified that, from a conceptual basis, the yield is in excess of investor return requirements. *Id*. This is because the base yield, the rate on A-rated utility bonds, is subject to credit risk. *Id*. With credit risk, the expected return on the bond is below the yield-to-maturity. *Id*. Hence, the yield-to-maturity of the bond is above the expected return. *Id*.

Second, Mr. Rea's methodologies to estimate the risk premium are similar to those he used in developing the equity or market risk premium in his CAPM approach and are subject to the same empirical flaws. *Id*., pp. 80-81. Dr. Woolridge notes that these flaws include: (1) the empirical problems associated with using historical market returns to estimate an expected risk premiums; and (2) the inflated expected risk premiums produced by Mr. Rea's (a) DCF application to the S&P 500 and (b) his use of the Value Line's 3-5 year stock return projections. *Id*.

Therefore, the Department should reject Mr. Rea's risk premium results, since he has grossly overstated the base yield, and over-inflated the risk premium used in the analysis.

##### *e) Comparable Earnings Approach.*

Mr. Rea estimates an equity cost rate of 14.0 percent for Bay State using the Comparable Earnings approach. Exh. CMA/VVR-1, pp. 145-154 and Exh. CMA/VVR-15. His methodology simply involves using the expected return on equity estimated by Value Line for a group of thirty companies 'comparable' in risk to Bay State. *Id*. These companies include such companies AT&T, CostCo, McKesson, Pfizer, and Verizon, among others. *See* Exh. CMA/VVR-15. As Dr. Woolridge recognized, these companies do not operate in a highly regulated environment and therefore are not an appropriate proxy for Bay State. Exh. AG/JRW-1, p. 82.

The Department has long held that such *ad hoc* comparable earnings approaches that fail to recognize the investment risk differences between firms in highly competitive industries and those that have regulated monopolies must be rejected. D.P.U. 09-30, pp. 360-361 (2009); *New England Gas Company*, D.P.U. 08-35, p. 207 (2008); *Boston Gas Company*, D.T.E. 03-40, pp. 359-360 (2003); *Commonwealth Electric Company*, D.P.U. 956, p. 54 (1982). The Company's analysis in this case simply reproduces the same old Value Line comparable earnings analysis that the Department has rejected time and time again. *Id*. The Company has not offered any new evidence or argument that should cause the Department to change it well-established precedent. Therefore the Department must reject the Company's comparable earnings analysis. *Id*.

##### *f) Other Issues.*

###### (1) Revenue Stabilization Mechanisms.

Mr. Rea has concluded that no return on equity reduction is needed for the Company's revenue decoupling mechanism, since any decreased risk associated with decoupling is already reflected in the stock prices of the companies in his gas LDC group. Exh. CMA/VVR-1, pp. 47-55. Mr. Rea comes to this conclusion based on his study in which he claims that the companies in his gas LDC group already have a wide-range of revenue stabilization mechanisms ("RSMs") in place, including full decoupling, revenue normalization, weather normalization, rate stabilization straight fixed variable rate design, and conservation incentive programs, among others. *Id*. He claims that 91.46 percent of the customers of the companies in the gas LDC group are either fully or partially revenue stabilized. *Id*.

There are several errors in Mr. Rea's RSM analysis which invalidate his conclusion. Exh. AG/JRW-1, pp. 85-87. As Dr. Woolridge testified, the number of decoupled customers is not necessarily a good proxy for decoupled revenues. *Id*. One example is that fact that large commercial and industrial customers bills are based on gas volumes consumed. *Id*. A second issue is that Mr. Rea's decoupled percentage figures include not only customers of companies that have a full revenue decoupling rate design mechanism, but also customers of companies with a weather normalization adjustment ("WNA"), and customers of companies that have a straight-fixed variable ("SFV") RSM. *Id*. Hence Mr. Rea's summary figures overstate the percent of fully decoupled customers. *Id*. Third, and most importantly, Dr. Woolridge emphasizes that by only addressing the revenues associated with decoupled customers, Mr. Rea missed the impact of unregulated revenues on the riskiness of the companies in his gas LDC group.[32] *Id*. Dr. Woolridge shows that whereas Bay State gets 98.32% percent of its revenues from regulated gas revenues (Tr. Vol. IV, p. 409), the companies in Mr. Rea's gas LDC group only receive 70 percent of revenues from regulated gas operations. Exh. AG/JRW-1, p. 83. Therefore, a significant portion of the revenues of these companies are not related to regulated gas distribution and, therefore, are not subject to a RSMs such as SFV or WNA rate designs. *Id*.

[32] In Exh. AG-5-10, Mr. Rea was asked for the percent of decoupled gas revenues (and not customers) for the companies in his gas LDC group. In response, Mr. Rea indicated that he did not have the requested data. In Exh. AG-5-11, Mr. Rea was asked for the percentage of decoupled gas volumes for the companies in his gas LDC group. Once, again, he could not provide the data.

Dr. Woolridge also indicates that the non-utility operations of these companies are associated with unregulated activities that are riskier and more volatile than regulated gas utility operations. *Id*.

Therefore, the Department can reduce the Company's allowed return on common equity from those analyses based on the LDC comparison group, since the decreased risk associated with decoupling is not reflected in the stock prices of all of the companies in the LDC group.

### 7. THE ATTORNEY GENERAL'S RECOMMENDATION.

The Department should reject Bay State's proposed cost of capital, because the analyses that were used to develop that cost were fatally flawed in myriad ways. Instead, the Department should rely on the testimony and analysis of Dr. Woolridge.

First, Dr. Woolridge has adjusted the Company's proposed capital structure to more accurately reflect the capitalizations of gas distribution companies and Bay State's parent, NiSource, recommending that the Department use a 50 percent debt and 50 percent common equity capital structure. Regarding his cost of common equity estimate, Dr. Woolridge highlights several factors that support his return on equity recommendation: (1) as he shows in Exhibit JRW-8, the gas distribution industry is Value Line's lowest risk industry as measured by beta; (2) as he shows in Exhibit JRW-3, capital costs for utilities, as indicated by long-term bond yields, are at historically low levels; and (3) Dr. Woolridge indicates that while the financial markets have recovered significantly in recent years, the economy has not. Dr. Woolridge testified that with interest rates and inflation at very low levels, the expected returns on financial assets – from savings accounts to Treasury bills to common stocks – are low. Based on these current market conditions and his cost of equity analysis, Dr. Woolridge recommends that the equity cost rate for Bay State to be in the range of 7.30 to 8.75 percent by applying the DCF and

CAPM approaches to his Gas Proxy Group. Therefore, the Department should use an overall weighted cost of capital of 7.29 percent for the Company's gas distribution operations in determining the return on rate base in the cost of service.

## I. Rate Structure

### 1. ALLOCATION OF REVENUES

#### *a) Background*

According to the Bay State's initial filing, Bay State used the proposed base revenue requirement and the allocated Cost of Service Study's results at equalized rates of return by rate class to target the initial rate increases. Exh. CMA/JAF-1. It then tested for classes that would experience a rate increase of 25 percent or more than the total company base revenue increase consistent with past precedent. Based on this analysis, Bay State determined that Residential Non-Heating, Outdoor Lighting, C/I (52) High Annual, Low Winter and C/I (53) Ex. High Annual, Low Winter were over the 25 percent cap and subsidies would need to be provided to these classes from all other rate classes. Exh. CMA/JAF-2, Schedule JAF-2-1. The AGO's witness, Ms. Rebecca Bachelder, proposed if the subsidized class's total bill percent increase is less than the average for the Company, the class should not receive a subsidy until the class percent increase in revenue reaches at least the company average percent increase. This would have prevented rate classes with larger overall bill impacts from subsidizing those with lower overall bill impacts. Exh. AG/RSB-1, pp. 3–4.

Both proposals, however, became moot due to modifications to the Massachusetts General Laws. Under the Department's prior precedent, if one or more rate classes receive an increase greater than 125 percent of the overall distribution rate increase, the increase as to any such class is "capped" at 125 percent. D.P.U. 09-30, p. 386 and cases cited. The Department's

125 percent cap, however, was superseded by an act of the General Court. Specifically, the General Court passed St. 2012, c. 209, An Act Relative to Competitively Priced Electricity in the Commonwealth (the "Act"), which became effective in relative part for 2013. The Act contained a section regarding the rate design, as follows:

> In each base distribution rate proceeding conducted by the department under section 94, the department shall design base distribution rates using a cost-allocation method that is based on equalized rates of return for each customer class; provided, however, that if the resulting impact of employing this cost-allocation method for any 1 customer class would be more than 10 per cent, the department shall phase in the elimination of any cross subsidies between rate classes on a revenue neutral basis phased in over a reasonable period as determined by the department.

Act, § 20. The Act modifies Chapter 164 by directing the Department in each base distribution proceeding to design base distribution rates based on equalized rates of return by customer class subject to a smoothed phase-in period for impacts greater than 10%. *Id*. Essentially, the Act preempts the Department's 125 percent cap and replaces it with a new 10 percent cap based, not on a percentage of the rate increase like the Department's 125 percent cap, but on "resulting impacts," i.e. bill impacts. *See* Exh. RR-DPU-11. Thus, under the Act, if any rate class is set to receive bill impacts greater than 10 percent, the increase is capped at 10 percent.

In addition, the Act requires the Department to commence a proceeding for each gas and electric distribution company to establish a cost-based rate design for costs that are currently recovered from distribution customers through a reconciling factor. Act, § 51. These rates are currently under investigation for each electric and gas distribution company. *See Investigation by the Department of Public Utilities to Establish a Cost Based Rate Design*, D.P.U. 12-126 (A-I).

#### *b) The Department Should Use Rate Decreases for Customers Receiving Rate Decreases in D.P.U. 12-126 to Eliminate Any Potential Subsidies Here*

The Department can and should use rate decreases that certain customer classes will experience to avoid the application of the Act's 10 percent cap. Bay State is in an unusual position where both increases in base rates and a reallocation of rates formerly included in base rates in D.P.U. 12-126 will go into effect in 2014. The order D.P.U. 12-126 will produce increases for some rate classes and decreases for others, primarily the larger commercial and industrial classes. Exh. RR-DPU-11. With large decreases expected for the larger commercial industrial classes from D.P.U. 12-126, the Department can and should avoid subsidies to those classes by using the rate impacts from the two proceedings to offset one another.

Indeed, only the residential non-heating class is subject to the 10 percent cap once the rate changes associated with D.P.U. 12-126 are incorporated into the calculations. Exh. RR-DPU-11. The Record Request response proposes capping the residential non-heating increase at 4 percent so that the total increase for the residential non-heating class as a result of this proceeding and D.P.U. 12-126 would be less than ten percent. *Id.* The AGO has no objection to this proposal.

### 2. RECONCILING MECHANISM COSTS SHOULD BE CONSIDERED AS PART OF THE "RESULTING IMPACT" IN THE NEW 10 PERCENT CAP CREATED BY THE ACT

In both this and future proceedings, any increases to amounts recovered through reconciling mechanisms should be considered as part of the "resulting impact" under the new 10 percent cap set forth by the Act. Reconciliation mechanisms are designed for distribution companies to recover costs that were previously recovered in base rate proceedings, but have been separated from base rates due to the significance of the costs and their volatility. For Bay

State, these include Pension and Post-Retirement Benefits, Targeted Infrastructure costs, Revenue Decoupling, Energy Efficiency Costs, Attorney General Consulting Expenses as well as other costs. By its response to RR-DPU-11, the Company suggests that these reconciling mechanisms should not be included in rate increases limited by Section 20 of the Act. *See* Exh. RR-DPU-11. If a representative test year level of these costs were to be included in base rates as they should be (with the exception of Revenue Decoupling) with the mechanisms reflecting only differences from test year costs, reconciliation cost increases would clearly be limited by Section 20 of the Act, along with other rate increases Bay State proposes.

Thus, the Department should consider rate class increases emanating from D.P.U. 12-126-A in this proceeding for the aforementioned reasons. Additionally, Bay State customers will be experiencing rate impacts from both proceedings in the rate year, and it is within the discretion of the Department to limit significant adverse rate impacts such as those faced by residential non-heating customers as a result of the combination of this proceeding and D.P.U. 12-126. The Department should consider the bill impacts of both proceedings in the context of Section 20 of the Act when it establishes the revenue allocation by class in the instant proceeding.

### 3. EXTRA LARGE COMMERCIAL / INDUSTRIAL CLASS CUSTOMER CHARGES SHOULD BE CALCULATED USING THE FULL COST BASIS OF THE CLASS

The Department should adopt the proposal of the AGO's witness Ms. Bachelder for the customer charge for the Extra-Large Commercial Industrial Classes. Exh. AG/RSB-1, pp. 7–8. Ms. Bachelder identified that the customer charges as proposed by the Company were at a lower percentage of cost-based customer charges than current customer charges. Ms. Bachelder proposed using the full cost basis of the class with the lower customer charge to provide proper price signals to these customers who have the greatest ability to change usage in response to price signals. *Id*. This approach is supported by the Company's witness, Mr. Joseph A. Ferro, citing the fact that moving to a full cost-based customer charge would help satisfy the goal of fairness by reducing intra-class subsidies. Exh. CMA/JAF-Rebuttal-1, pp. 6-7.

#### 4. THE DEPARTMENT SHOULD ELIMINATE INCLINING BLOCK RATES FOR GAS COMPANIES AND DECLINE TO REDESIGN INCLINING BLOCK RATES IN ORDER TO INCREASE THEIR IMPACT

The Department should eliminate inclining block rates from Bay State's rate design, and it should not consider revising Bay State's inclining block rates by increasing the difference between the "head" and "tail" blocks. In Bay State's last rate case, the AGO contended that inclining block rates should be eliminated on a number of grounds. *See* D.P.U. 12-25, AG Br., p. 191. First, maintaining the correct price signals for natural gas will benefit the environment by encouraging customers to switch from heating oil and electric appliances to natural gas. *Id*., p. 192. Second, customers have sufficient incentive to conserve without inclining block rates, given that they pay higher delivery and supply charges when they fail to conserve. *Id*. Third, inclining block rates create inter-class and intra-class subsidies. Inclining block rates impose higher costs per unit on high usage customers, even though the marginal cost to deliver those additional units to those customers is lower. *Id*., pp. 193–94. Accordingly, inclining block rates for natural gas violates the principles of fairness and efficiency, which hold that rates should reflect the underlying costs of providing service. *Id*., p. 194. Finally, customers are simply not aware of inclining block rates, so they likely have little to no effect on customers' efforts to conserve. *Id*., pp. 194–95. The AGO continues to oppose inclining block rates for the same reasons set forth in its briefing in Bay State's last rate case.

Although the Department ultimately declined to eliminate inclining block rates, the Department nevertheless acknowledged that it had its "own concerns about inclining block rates" and that it was "not fully persuaded" that inclining block rates encourage end-use energy efficiency. Bay State, D.P.U. 12-25, p. 468. Consistent with its prior reservations concerning inclining block rates, the Department should take the opportunity here to eliminate inclining block rates.

All of the evidence in this proceeding regarding inclining block rates supports the concerns that the AGO expressed in D.P.U. 12-25. Bay State's witness, Mr. Ferro, testified that even most of the Company's commercial and industrial customers are not aware that they are billed on inclining block rates. Tr. Vol. VI, pp. 634–35. Indeed, Mr. Ferro testified that he believed that not one customer has "expressed its sensitivity towards that portion of its charges that it would be inclined to even notice it…." *Id.*, p. 659. Moreover, even if a customer were aware of inclining block rates, he or she would be "hard-pressed to, to be aware of the costs and associated bill impact of the inclining block rate structure within the month as the customer's using…" *Id.*, p. 634. Accordingly, the evidence here indicates that customers are not aware of inclining block rates and even if they were, customers would, at best, have considerable difficulty in changing their behavior in order to avoid the higher rate block. Given that the purpose of inclining block rates are to encourage customers to conserve by imposing higher rates for high use, where customers simply do not know that inclining block rates exist, and would not be able to conform their behavior to respond if they did, the evidence in this proceeding suggests that inclining block rates have middling to no effects on customers' efforts to conserve. *See* Bay State Gas, D.P.U. 12-25, p. 468. Given the considerable drawbacks of inclining block rates—such as a decline in economic efficiency and the creation of intra- and inter-class subsidies—the trade-off is simply not worth it.[33]

[33] Indeed, Bay State's witness testified that he would prefer that rates be designed to include a fixed distribution charge with a small volumetric component that would seek to represent the marginal cost of providing service. Tr.

Nor should the Department consider revising Bay State's inclining block rates to increase their impact on high and low volume customers.  As Bay State's witness acknowledged, increasing the difference between the head and tail block would exacerbate the existing issues with inclining block rates by increasing subsidies and reducing the simplicity and fairness of a cost-based rate structure.  Tr. Vol. VI, p. 658–59.  The prospect of increasing customer awareness by increasing the block differential is speculative at best, given Mr. Ferro's testimony that customers have not demonstrated any awareness of inclining block rates in the past, and that customers are generally sensitive to total bills, rather than any portion thereof.  *Id*., pp. 659–60. Moreover, even if the increased block differential did cause some customers to become aware of inclining block rates that increased awareness would have little to no overall effect on conservation.  Increasing the differential between the head and the tail block would do nothing to make it practical for customers to actually respond to the price differential because customers have no way to measure their consumption in a given month until they actually receive their bills.  *Id*., p. 634.  Indeed, there is absolutely no evidence in this proceeding that would support changing the basis for inclining block rates.  *Id*., p. 672.  Accordingly, the Department should eliminate inclining block rates and decline to revise Bay State's inclining block rates to increase the differential between the head and the tail blocks.

Vol. VI, p. 635.  Moreover, Bay State's witness further testified that he felt that inclining block rates were "more sizzle than steak" and that they were "ill-conceived."  *Id*., p. 660.

## VII. CONCLUSION

The Department should reject the Company's proposed rate increase and should accept the AGO's recommendations as set forth in this brief as they are in the interest of the Company's customers.

Respectfully submitted,

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