October 31, 2003

D.T.E. 03-40

Petition of Boston Gas Company d/b/a KeySpan Energy Delivery New England, pursuant to General Laws Chapter 164, § 94, and 220 C.M.R. § 5.00 et seq. for a General Increase in Gas Rates.

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I. INTRODUCTION

A. Procedural History

On April 16, 2003, Boston Gas Company d/b/a Keyspan Energy Delivery New England ("Boston Gas" or "Company") filed with the Department of Telecommunications and Energy ("Department"), pursuant to G.L. c. 164, § 94, a petition seeking a $61.3 million[1] (9.59 percent) increase in its total rates or a $65.4 million increase (22.7 percent) in its base distribution rates for firm gas customers (Exh. DTE 4-9, at 3). The Company uses a test year ending December 31, 2002 (Exh. KEDNE/PJM-1, at 3). The petition also includes a request for approval of the Company's price cap performance-based rate ("PBR") plan, under which the Company proposes to adjust its rates annually for five years (id. at 2-3). The Department suspended the tariffs for further investigation until November 1, 2003.

Boston Gas is a wholly-owned subsidiary of Keyspan Corporation ("Keyspan") and supplies gas service to approximately 573,000 customers in municipalities in eastern and central Massachusetts (Exh. KEDNE/JFB-1, at 9).[2] The Company's last general base-rate increase and PBR plan were authorized by the Department on November 29, 1996. Boston Gas Company, D.P.U. 96-50 (Phase I) (1996).

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[1] In addition to the $61.3 million increase to total rates, the Company proposes to collect $4.4 million of post-retirement benefits other than pensions ("PBOP") expenses through a reconciliation adjustment mechanism (Exh. KEDNE/JFB-1, at 38).

[2] Keyspan, a public-utility holding company formed in 1998 and headquartered in Brooklyn, New York, acquired Boston Gas' parent company, Eastern Enterprises, in November 2000 (Exh. KEDNE/JFB-1, at 7).

Pursuant to notice duly issued, the Department held four public hearings in the Company's service territory to afford interested persons an opportunity to comment. The hearings were held on May 19, 2003, in Boston; on May 20, 2003, in Acton; on May 21, 2003, in Lynn; and on May 22, 2003, in Quincy. The Attorney General of the Commonwealth of Massachusetts ("Attorney General") filed a notice of intervention as of right, pursuant to G.L. c. 12, § 11E. The Department granted the petitions for intervention of the Commonwealth of Massachusetts Division of Energy Resources ("DOER"), Bay State Gas Company ("Bay State"), Berkshire Gas Company ("Berkshire"), the Massachusetts Oil Heat Council, Inc. and the Massachusetts Alliance for Fair Competition, Inc. ("MOC"), the Massachusetts Development Finance Agency ("MDFA"), the Massachusetts Community Action Program Directors Association, Inc. ("MassCAP"), Associated Industries of Massachusetts ("AIM"), and the United Steelworkers of America, AFL-CIO-CLC. The Department granted limited participant status to Fitchburg Gas and Electric Light Company ("Fitchburg"), NStar Gas and Electric Corporation, Western Massachusetts Electric Company, New England Gas Company, and The Energy Consortium.

Twenty-six days of evidentiary hearings were held between June 26 and August 11, 2003. Initial briefs were filed by MDFA on August 26, 2003, and by the Attorney General, DOER, MassCAP, MOC, and Bay State on August 29, 2003. The Company filed its initial brief on September 10, 2003. The Attorney General, DOER, MDFA, MOC, and AIM filed reply briefs on September 17, 2003, and the Company filed its reply brief on September 24, 2003. The evidentiary record consists of 1,994 exhibits, including 66 Boston Gas exhibits,

45 Attorney General exhibits, one MassCAP exhibit, and two MOC exhibits, as well as all responses to discovery and record requests. On October 9, 2003, the Department granted the Company's motions for protective treatment of confidential information filed in the proceeding.

In support of its filing, Boston Gas sponsored the testimony of the following eight witnesses: Joseph F. Bodanza, senior vice-president of regulatory affairs and chief accounting officer for Keyspan Corporation; Patrick J. McClellan, director of rate recovery for Keyspan Corporate Services, L.L.P.; Justin C. Orlando, vice-president of human resources for Keyspan Corporate Services, L.L.P.; Lawrence R. Kaufmann, partner at Pacific Economics Group, L.L.C. ("PEG"); Paul R. Moul, managing consultant of P. Moul and Associates; Ann E. Leary, manager of rates for Keyspan Energy Delivery New England; A. Leo Silvestrini, director of rates and regulatory affairs for Keyspan Energy Delivery New England; and Ronald B. Edelstein, director of state regulatory programs for the Gas Technology Institute ("GTI"). Mr. McClellan, Mr. Kaufmann, and Mr. Moul also provided rebuttal testimony for the Company.

The Attorney General presented rebuttal testimony of David J. Effron, utility regulation consultant with the Berkshire Consulting Group, and Lee Smith, management consultant and senior economist for LaCapra Associates. Timothy Newhard, financial analyst in the Utilities Division of the office of the Attorney General, and Ms. Smith offered surrebuttal testimony for the Attorney General. MassCAP presented the testimony of Elliott Jacobson, director of energy services for Action, Inc.

B. Outstanding Motions

1. Motion to Bifurcate

a. Introduction

At the May 23, 2003 procedural conference, the Attorney General moved that the Department sever the PBR portion of this proceeding from the revenue requirement portion (Tr. E, at 12-17). In support of the motion, the Attorney General stated that the procedural schedule was unworkable because witnesses would be unavailable, the Company had not been forthcoming with discovery responses on the PBR issues, and the PBR plan would be "short-changed" given the limited time available (id. at 12-16). According to the Attorney General, staying the PBR issues for a later separate phase would be in the interest of administrative efficiency (id. at 16). The Attorney General renewed the motion at the June 23, 2003 procedural conference (Tr. F, at 11-12). DOER supported the motion (Tr. E, at 18-20). The Company opposed the motion, responding that the PBR issue was not as complicated as the Attorney General asserted and that it could be addressed in the time allotted (id. at 17-18).

b. Analysis and Findings

The Attorney General's motion, based on the procedural schedule, is moot. The Department proceeded with evidentiary hearings and briefing that included the PBR issues, and now decides all of the revenue requirement and PBR issues in this Order.

2. Motion to Strike Portions of Boston Gas' Initial Brief

a. Introduction

Pursuant to 220 C.M.R. §§ 1.04(5) and 1.11(7),(8), the Attorney General filed a motion to strike portions of Boston Gas' initial brief on September 18, 2003 ("Attorney General Motion to Strike") and a supplement to that motion on September 19, 2003 ("Motion to Strike Supp."). Boston Gas filed an opposition to the motion on September 26, 2003 ("Boston Gas Opposition"). The Attorney General then responded to the opposition on October 2, 2003 ("Attorney General Response").

b. Positions of the Parties

i. Attorney General

The Attorney General asserts that the portions of the brief he moves to strike consist of extra-record evidence, because the information was not produced during the hearings, presented with proper citation to the record, or preceded by a motion to reopen the record to admit post-hearing evidence[3] (Attorney General Motion to Strike at 1-2). Therefore, the

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[3] The Attorney General moves to strike the following from the Company's initial brief: (1) two sentences on page 24 regarding reasonableness of cost of plant additions (the second sentence of the beginning paragraph, and the penultimate sentence of that section); (2) the second part of the second sentence of the first paragraph on page 26, regarding the West Roxbury project cost overrun; (3) portions of footnote 38, page 86, regarding the internal rate of return and net present value calculations; (4) the second, third, and fourth sentences in the last paragraph on page 100, regarding advertisement invoices; (5) the sentence that precedes footnote 88 on page 211, as well as the last sentence in footnote 88 on page 211, regarding staffing level reductions; (6) the last sentence in footnote 88 on page 211, regarding staffing level reductions; (7) the sentence ending page 211 and carrying over to page 212, regarding service quality standards; (8) the last part of the first complete sentence on page 212 regarding service

(continued…)

Attorney General argues, the Department's consideration of this information would violate the Attorney General's right under G.L. c. 30A, § 11(3) to subject evidence to cross-examination and to submit rebuttal evidence (id. at 2-3). The Attorney General requests that, unless the Company produces supporting citation to the record, the Department, in accord with precedent, either strike the information at issue from Boston Gas' brief and require the Company to file a conforming brief, or strike the portions of the brief and disregard them in reaching a decision in the case (id. at 3).

ii. Boston Gas

Boston Gas responds that none of the Company's statements contested by the Attorney General should be stricken, because they are all either based on direct factual evidence in the record, or involve reasonable inferences from that evidence (Boston Gas Opposition at 12-13). In support of the statements in its brief that the Attorney General moves to strike, the Company provides citations to the record, and where necessary provides explanations for statements it "reasonably calculated" or inferred from the record (id. at 2-12).

c. Analysis and Findings

A party may not in a post-hearing brief introduce new evidence or argue a new position unsupported by record evidence; and the Department cannot accord any weight to arguments

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[3] (…continued)
quality; (9) the second sentence of the paragraph under the second bullet on page six, stating that low pressure results from increased load on the system and is not related to leaks or leak repair; and (10) the penultimate sentence of footnote 47 on page 122, stating that work performed by the Company's legal counsel in investigating whether to file a rate case in 2002 "carried over" into the present rate case (Attorney General Motion to Strike at 3-5; Motion to Strike Supp. at 1).

that rely on extra-record information. MediaOne, New England Telephone, Greater Media Telephone Arbitration, D.T.E. 99-42/43, 99-52, at 17-18 (1999); D.T.E. 96-50-C at 11-13; Boston Gas Company, D.P.U. 88-67 (Phase II) at 7 (1989). Where an objection is raised by an opponent to an argument on brief that is not supported by the record, the Department may strike all or part of the argument. Fitchburg Gas and Electric Light Company, D.T.E. 02-24/25, at 8. Parties are entitled on brief to make arguments based on record evidence or reasonable inferences from record evidence, and the Department will give such arguments their due weight in light of the evidentiary record. See Cambridge Electric Light Company, D.P.U. 92-250, at 4 (1993); Braintree Electric Light Department, D.P.U. 90-263, at 24-25 (1991).

The Attorney General presents an extensive list of items he believes the Department should strike from the Company's brief as improperly introduced extra-record evidence. The Company exhaustively responded to the Attorney General's motion with specific references to the record evidence upon which the Company based the challenged statements in its brief and with comprehensive explanations of the means by which the Company derived its conclusions (Boston Gas Opposition at 2-12 (responding point by point with citations to record evidence for each of the ten portions of the brief the Attorney General moved to strike)). The Department has thoroughly reviewed the evidence cited and finds that the Company has demonstrated that the specific passages the Attorney General challenges are conclusions or characterizations based on record evidence, or on reasonable inferences from the record evidence; in other words, they consist of permissible argument. The Company is entitled to make its arguments

as to what the record demonstrates.[4] Likewise, in his motion, the Attorney General has made arguments that the record fails to demonstrate what the Company asserts it does.[5] These arguments are appropriately considered in the Department's determinations below. Those passages that the Attorney General has included in his motion and characterized as unsupported by the evidence will be afforded due weight in light of the evidentiary record in this case. See D.P.U. 92-250, at 4; D.P.U. 90-263, at 24-25. In addition, we find that, because the Company did not rely on extra-record evidence, the Company was not required to file a motion to reopen the record prior to making these statements on brief. The Department therefore declines to strike the challenged portions of the Company's initial brief, and, accordingly, denies the Attorney General's Motion to Strike.

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[4] With regard to the fifth item the Attorney General moves to strike, the sentence preceding footnote 88 on page 211 plus the last sentence in footnote 88, regarding staffing level reductions (Attorney General Motion to Strike at 4), the Company argues that its conclusion regarding staff reductions is based on the fact that G.L. c. 164, § 1E allows for such staffing reductions and the Company's assumption that staff reductions complied with the law (Boston Gas Opposition at 10; Boston Gas Brief at 210-211). The Company may make an argument that the absence of contrary evidence supports its conclusion. The Department, therefore, declines to strike the passages objected to, but will give the Company's statement the appropriate probative value in light of the evidentiary record in reaching our determinations in Section VIII.F, below.

[5] The Attorney General argues that the Company's citations to evidence to support its statements on service quality (Boston Gas Opposition at 10-11) are inadequate because the Company provides only broad citation to exhibits without providing specific citations as to which parts of large exhibits support the Company's assertions (Attorney General Response at 4-5). However, the record contains the Company's service quality reports, and therefore, the arguments the Company makes about the contents of these reports are supported by record evidence. Therefore, the Department declines to strike the statements, but will give the Company's interpretation due weight in making our determinations in Section VIII.F, below.

II. REVENUES

A. Introduction

Boston Gas proposes a number of adjustments to test year revenues in order to establish a representative level for the determination of its revenue deficiency or surplus. The Company's proposed adjustments to test year revenues are discussed below.

B. Billing Day Adjustment

1. Introduction

The Company proposes a billing day adjustment to account for the revenue impact caused by the difference between the number of billing days in a normal year (365.25) and the number of billing days in the test year (365.45) (Exhs. KEDNE/AEL-1, at 6-7; KEDNE/AEL-2, at 6). Boston Gas calculates its proposed billing day adjustment in the same manner as approved by the Department in its last rate case, D.P.U. 96-50, and the subsequent PBR compliance filings in Boston Gas Company, D.T.E. 98-98 (1998), Boston Gas Company, D.T.E. 99-85 (1999), Boston Gas Company, D.T.E. 00-74 (2000), and Boston Gas Company, D.T.E. 01-74 (2001) (Exhs. AG 8-35; AG 8-36). The proposed billing day adjustment reduces the Company's test year revenues by $164,726. No other parties commented on the proposed adjustment.

2. Analysis and Findings

The average number of days in the Company's monthly meter reading schedule varies by the average number of days in each billing cycle.[6] Consequently, the average number of billing days in a given month will not necessarily be equal to the number of calendar days for that month. Therefore, the Department adjusts test year revenues to recognize the level of revenues that would likely be collected during a normal calendar year. D.P.U. 96-50 (Phase I) at 39-40; D.P.U. 93-60, at 80-83. We find that Boston Gas calculated its proposed billing day adjustment consistent with the method approved by the Department in its last rate case, D.P.U. 96-50, and the subsequent PBR compliance filings in D.T.E. 97-92, D.T.E. 98-98, D.T.E. 99-85, D.T.E. 00-74, and D.T.E. 01-74. Therefore, we accept Boston Gas' proposed billing day adjustment, reducing the Company's test year revenues by $164,726.

C. Customer Charge Adjustment

1. Introduction

The Company proposes to reduce its test year revenues by $543,219 to account for a change in the calculation of its customer bills resulting from the conversion to the Customer Related Information System ("CRIS") in July 2002 (Exh. KEDNE/AEL-1, at 8). The CRIS calculates customers bills based on the number of days in a customer's billing cycle, as opposed to a fixed monthly amount (id.). This change in bill calculation method caused the Company to file new rate tariffs, effective July 1, 2003, that have lowered the customer charge

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[6] Boston Gas' monthly meter reading schedule consists of 21 billing cycles with each cycle having 26 to 34 days (Exh. DTE 2-51).

for all rate classes, affecting the amount of revenue the Company bills through the customer charge portion of its rates (id.).[7] Boston Gas proposes to calculate the customer charge adjustment by comparing the customer charges actually billed to what would have been billed if the CRIS was in place beginning January 1, 2002 (id.). No other parties commented on the proposed adjustment.

2. Analysis and Findings

In determining the propriety of rates for the companies under its jurisdiction, the Department has consistently based allowed rates on test year data, adjusted for known and measurable changes. D.T.E. 02-24/25, at 76. The selection of an historic twelve-month period of operating data as the basis for setting rates is intended to provide for a representative level of a company's revenues and expenses which, when adjusted for known and measurable changes, will serve as a proxy for future operating results. Id.

The Company changed its customer charges in the middle of the test year because of the conversion to the CRIS. The reduction in operating revenues to account for a change in the calculation of its customer bills resulting from the conversion to the CRIS constitutes a known and measurable change to test year revenues. Therefore, we accept Boston Gas' proposed customer charge adjustment, reducing the Company's test year revenues by $543,219.

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[7] Under the CRIS, the changes that appear in the applicable rate tariffs are prorated based on a 30-day billing cycle. Under the old billing method, if the number of days in the billing cycle was between 26 and 34 days then the charges that appeared under the applicable rate tariff were not prorated to calculate the bill amount. In Keyspan Energy Delivery New England, D.T.E. 02-32, at 1-4 (2002), the customer charges and tailblock rates were revised such that the change to the CRIS billing method was revenue neutral to the Company.

D. Unbilled Revenues Adjustment

1. Introduction

Boston Gas proposes an unbilled sales/revenue adjustment to account for the difference between the amount of gas it delivered to customers during the test year and the amount of gas it billed to customers during that same period (Exh. KEDNE/AEL-1, at 10). The Company calculated this proposed adjustment by subtracting gross unbilled sales volumes for December 2001 from gross unbilled sales volumes for December 2002 (id. at 11). The difference was then multiplied by the Company's average base rate to determine unbilled base revenues and by the average gas cost rate to determine unbilled gas costs (id.). The Company's unbilled sales/revenue adjustment reduces test year base revenues by $15,926,040 and test year gas revenues by $11,244,090, resulting in a $4,681,950 net overall reduction to test year revenues (id. at 11-12). No other parties commented on the proposed adjustment.

2. Analysis and Findings

The Department has found that unbilled revenues should be included in test year cost of service. See Berkshire Gas Company, D.T.E. 01-56, at 32. Boston Gas has calculated its proposed unbilled sales/revenues adjustment consistent with the method approved by the Department in its last rate case, D.P.U. 96-50, and the subsequent PBR compliance filings in D.T.E. 97-92, D.T.E. 98-98, D.T.E. 99-85, D.T.E. 00-74, and D.T.E. 01-74 (Exh. DTE 4-52). Therefore, the Department accepts Boston Gas' proposed unbilled sales/revenue adjustment, reducing the Company's test year revenues by $4,681,950.

E. Late Payment Charge Adjustment

1. Introduction

During the test year, the Company booked revenues associated with late payment charges of $479,721 (Exh. KEDNE/AEL-1, at 12). However, the Company states that the booked amount is understated because the late payment charge calculation was programmed incorrectly during its conversion to the CRIS (id.; Exh. DTE 1-30). Instead of the amount booked in the test year, Boston Gas proposes to use the total of actual late payment charges incurred from July 2001 to June 2002, or $1,118,138, as a representative level of test year late payment revenues. Accordingly, the Company proposes to increase test year revenues by $638,418 (Exh. KEDNE/AEL-1, at 12). No other parties commented on the proposed adjustment.

2. Analysis and Findings

In D.P.U. 93-60, at 84-85, the Department found the proper amount of late payment charge revenues to include for ratemaking purposes is a function of revenues. In that Order, the Department found that the late payment charge revenue adjustment must reflect the historical relationship between late payment charge revenues and total revenues. Id. at 85. The Department instructed the Company to incorporate a three-year weighted average ratio of late payment charge revenues to total non-residential revenues into its late payment charge revenue adjustment. Id. at 84-85.

The Company's proposal to substitute the actual late payment charge revenues incurred from July 2001 to June 2002 as representative level of late payment revenues disregards the

effect that the amount of total revenues has on the amount of late-payment charge revenues in a given year. The Department, therefore, rejects the Company's calculation of its late payment charge adjustment.

Consistent with our finding in D.P.U. 93-60, the Department has recalculated the Company's late payment charge revenue adjustment to recognize the three-year weighted average ratio. Because the late payment charge revenues for the test year are understated, and, therefore, are not an appropriate representative level, we will use the three-year weighted average ratio using late payment charge revenues and total commercial and industrial revenues for the period 1999 through 2001. By the Department's calculation, late payment charge revenues amount to 0.47 percent of total commercial and industrial revenues. Application of this 0.47 percent ratio to the Company's total commercial and industrial 2002 test year revenues yields a late payment charge revenue amount of $1,030,655. Because the test year included $479,721 in late payment charge revenues, the Department will increase the Company's test year revenues by $550,934 to include a representative level of late payment charge revenues.

F. Demand Side Management Incentive Adjustment

1. Introduction

Boston Gas proposes to remove $1,058,000 in revenues that were collected through its local distribution adjustment factor ("LDAF") during the test year to recover the incentive payments approved by the Department for implementation of the Company's demand side management ("DSM") programs (Exh. KEDNE/AEL-1, at 14). The proposed revenue

adjustment represents a portion of the DSM incentive approved by the Department for recovery during November 2001 through October 2002 and the entire DSM incentive approved by the Department for recovery beginning in November 2002 (Exh. AG 19-30). No other parties commented on the proposed adjustment.

2. Analysis and Findings

The DSM incentive represents the amount of revenue earned by the Company in relation to the incentives it achieved on the successful implementation of its DSM programs (Exh. AG 8-43). These revenues are not directly associated with base rates. Accordingly, in order to establish a representative level of the Company's annual revenues for the establishment of base rates, Boston Gas must remove DSM incentive payments collected through the LDAF from total operating revenues. After review, we find that the proposed adjustment to remove revenues collected through the LDAF during the test year to recover DSM incentive payments has been correctly calculated. Therefore, we accept Boston Gas' proposed DSM incentive adjustment, reducing the Company's test year revenues by $1,058,000.

G. Energy Efficiency Adjustment

1. Introduction

The Company proposes an adjustment to remove revenues that the Company billed to customers for the state-wide energy conservation service ("ECS") program during the test year (Exh. KEDNE/AEL-1, at 14). The proposed energy efficiency adjustment reduces test year revenues by $495,356 (id.).

2. Analysis and Findings

Because ECS expenses are recovered through surcharges on customer bills, and not through base rates, the Department has found that both ECS revenues and expenses should be removed from cost of service. Essex County Gas Company, D.P.U. 87-59, at 6 (1987). After review, we find that Boston Gas has correctly calculated its proposed adjustment removing test year revenues billed to customers for the ECS program. Therefore, we accept Boston Gas' proposed energy efficiency adjustment, reducing the Company's test year revenues by $495,356.

H. Non-Firm Revenues Adjustment

1. Introduction

The Company proposes an adjustment to remove revenues that Boston Gas billed to its non-firm customers under interruptible sales and interruptible transportation contracts during the test year (Exh. KEDNE/AEL-1, at 14). The proposed adjustment reduces test year revenues by $6,274,641 (id.). No other parties commented on the proposed adjustment.

2. Analysis and Findings

The Company derives non-firm revenues from interruptible sales and transportation contracts, distinct from distribution base rates. These non-firm sales are not directly associated with distribution base rates. Accordingly, in order to establish a representative level of the Company's annual revenues for the establishment of base rates, Boston Gas must remove non-firm revenues from total operating revenues. After review, we find that Boston Gas has

correctly calculated its proposed non-firm revenues adjustment. Therefore, we accept Boston Gas' proposed adjustment, reducing the Company's test year revenues by $6,274,641.

I. Broker Revenues Adjustment

1. Introduction

The Company proposes an adjustment to remove revenues billed to third party gas suppliers (or brokers) during the test year (Exh. KEDNE/AEL-1, at 15). Third party gas suppliers are billed when the gas consumed by their transportation customers exceeds the gas that the suppliers delivered to the Company's gate stations (id.). The proposed broker adjustment reduces test year revenues by $4,261,765 (id.). No other parties commented on the proposed adjustment.

2. Analysis and Findings

Revenues billed to third party gas suppliers (or brokers) during the test year are not directly associated with base rates. Accordingly, in order to establish a representative level of the Company's annual revenues for the establishment of base rates, Boston Gas must remove broker revenues from total operating revenues. After review, we find that the proposed adjustment to remove revenues billed to brokers during the test year has been correctly calculated. Therefore, we accept Boston Gas' proposed broker revenues adjustment, reducing the Company's test year revenues by $4,261,765.

J. PBR Revenues Adjustment

1. Introduction

Boston Gas proposes an adjustment to remove $3,864,000 in PBR-related

revenues booked in the test year that are applicable to deferred revenues from prior years (Exh. KEDNE/AEL-1, at 13). On March 7, 2002, the Massachusetts Supreme Judicial Court ("SJC") rendered a decision vacating the Department's ruling in Boston Gas Company, D.P.U. 96-50-D (2001). Boston Gas Company v. Department of Telecommunications and Energy, 436 Mass. 233 (2002). According to the Company, the Department's Order in D.P.U. 96-50-D would have increased the accumulated inefficiencies factor contained in the price-cap formula under the Company's PBR plan (Exh. KEDNE/AEL-1, at 13). The Company states that an increase in the accumulated inefficiencies factor would have reduced the revenues collected by the Company in subsequent annual periods covered by the PBR plan (id. at 13). When the SJC stayed the Department's decision in D.P.U. 96-50-D on February 7, 2001, Boston Gas deferred, pending the outcome of the Company's appeal to the SJC, the revenues it would have had to return to its ratepayers if the accumulated inefficiencies factor were included in rates (id. at 15). When the SJC decided the appeal in the Company's favor on March 7, 2002, Boston Gas booked the deferred revenues. The Company now proposes to remove the related $3,864,000 in revenues booked in the test year that were applicable to deferred revenues from prior years (id.). No other parties commented on the proposed adjustment.

2. Analysis and Findings

The Department finds that the Company's proposed PBR revenues adjustment is reasonable because it removes revenues that will not occur in the future, and instead were

deferred from prior years to the test year. Therefore, we accept Boston Gas' proposed PBR revenues adjustment, reducing the Company's test year revenues by $3,864,000.

K. Weather Normalization Adjustment

1. Introduction

The Company proposes a weather normalization revenue adjustment to increase its test year revenues by $5,652,892 (Exh. AG 8-30 [rev.] at 2-3).[8] The Company states that this adjustment, derived by calculating the throughput and associated revenues that would have occurred had the weather been normal, will eliminate the effects on its test year revenues of deviations from normal weather (Exh. KEDNE/AEL-1, at 3).

Boston Gas used normal degree days to calculate the throughput associated with normal weather. The Company calculated normal degree days by taking the average daily degree days over the 20-year period from 1983 through December 2002 (id. at 4). The Company states that its method for calculating the proposed weather normalization adjustment is the same method approved in its last rate case, D.P.U. 96-50, except that normal degree day data used to weather-normalize each customer's throughput from January 2002 through June 2002 was not based on a 20-year average, but rather a ten-year average that showed a difference of

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[8] The Company initially proposed a weather normalization revenue adjustment of $5,520,760 (Exhs. KEDNE/AEL-1, at 3; KEDNE/AEL-2, at 2-3). During the proceeding, the Company corrected errors in its initial calculations arising from its conversion to the CRIS billing system and consequent adoption of a new method for calculating degree days (RR-DTE-19 [rev.]; Exhs. DTE 10-18 [rev.]; DTE 2-40 [rev.]; AG 8-30 [rev.]). As a result of these corrections, the Company's proposed weather normalization revenue adjustment increased from $5,520,760 to $5,652,892 (Exh. AG 8-30 [rev.]).

17 degree days, or 0.4 percent (Exh. DTE 2-43). The Company explains that the use of the shorter ten-year average was required because it lacked access to its old billing system after the conversion to the CRIS billing system (id.). The Company states that it accounted for the monthly difference between the 20-year and ten-year average normal degree days by making adjustments on a rate class basis for each month (id.; Exhs. AG 8-30, Tab "DD Correction;" AG 8-30 [rev.]; RR-DTE-19 [rev.]).

The Company states that, consistent with the method approved in its last rate case, it performed its weather normalization adjustment on a customer-by-customer basis for all weather-sensitive rate classes except G-44 and G-54 (Exh. KEDNE/AEL-1, at 4-6). In performing this customer-by-customer adjustment, the Company first split the customer's actual billed use for each month during the test year into base load and heating use. Base load was calculated as the average use in the billing months of July and August, and heating use as the difference between billed use and base load (id. at 4; RR-DTE-88). Normal heating use was calculated by multiplying the customer's actual heating use by the ratio of normal degree days to actual degree days for the associated billing period (Exh. KEDNE/AEL-1, at 4). The customer's normal use is the sum of the base load and the normal heating use (id.).

Once the Company calculated the total normal throughput for each rate class, which is the sum of each customer's normal use in that rate class, the Company determined the weather normalized throughput adjustment by subtracting the actual headblock and tailblock throughput from the normalized headblock and tailblock throughput, respectively, for each rate class for each month (id. at 4-5; Exh. KEDNE/AEL-2, at 2). Finally, the Company calculated the

associated test year weather normalization revenue adjustment by multiplying the normalized headblock and tailblock throughput adjustments by the corresponding headblock and tailblock volumetric charges for each rate class (Exhs. KEDNE/AEL-1, at 5; KEDNE/AEL-2, at 3).

For rate classes G-44 and G-54, charges are on a demand basis and the customer is billed for its maximum daily contract quantity ("MDCQ") that is fixed for the entire season. Therefore, the Company states that any changes in the customer's throughput resulting from warmer or colder than normal weather will not affect the customer's bill (Exh. DTE 2-46).[9] Consequently, in order to determine the revenue impact of changes from normal weather on rate classes G-44 and G-54, the Company weather normalized the aggregate MDCQ for each rate class (Exh. KEDNE/AEL-1, at 6). To do so, the Company first calculated the average normal daily use for each rate class,[10] multiplied the result by 30, and then divided by 21 to

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[9] The Company notes that under the current tariffs for Rates G-44 and G-54, customers are billed on a demand basis where the demand charge is calculated based on the customer's MDCQ (Exh. KEDNE/AEL-1, at 5). The Company states that it sets each customer's peak and off-peak MDCQs, that are fixed for a given season, equal to the customer's calculated MDCQ using the customer's throughputs in the prior seasons (id.; Exh. DTE 2-46).

[10] The Company states that the class normal throughput is the sum of all the customers' normal throughput in that class, determined on a customer-by-customer basis using the same method for all the other rate classes as described above (Exh. DTE 2-46; RR-DTE-27).

convert the result on a class normal MDCQ basis (id.).[11] To derive the class actual calculated MDCQ, the Company repeated this calculation, substituting actual monthly volumes for normal volumes (id.). The ratio of normal MDCQ to actual calculated MDCQ was then multiplied by the actual billed MDCQ, resulting in the normal billed MDCQ (id.). The difference between the class normal billed MDCQ and the class actual billed MDCQ was then multiplied by the effective MDCQ rate for that rate class resulting in the weather normalization revenue adjustments (id.).[12] No other parties commented on the proposed adjustment.

2. Analysis and Findings

The Department's standard for weather normalization of test year revenues is well established. See D.T.E. 02-24/25, at 75; D.P.U. 96-50 (Phase I) at 36-39; D.P.U. 93-60, at 75-80; Berkshire Gas Company, D.P.U. 92-210, at 194 (1993). The Company's proposed weather normalization adjustment is consistent with the Department's standard except for its use of a ten-year average degree days, instead of the 20-year average, to measure normal weather for the period January 2002 through June 2002 for the purpose of calculating the weather normalization adjustment on a customer-by-customer basis. Boston Gas explains that this discrepancy was the result of the Company's conversion to a new billing system. The

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[11] The Company stated that, consistent with the current tariffs for rates G-44 and G-54, this calculation is performed because there are 21 business days in a 30-day month. Because these customers generally operate on business days, the maximum daily use is the average monthly use divided by 21 days of operations (Exh. DTE 2-47).

[12] These calculations result in proposed weather normalization revenue adjustments for Rates G-44 and G-54 of $237,059 and $31,896, respectively. These adjustments are included in the proposed total weather normalization adjustment of $5,652,892 (Exhs. KEDNE/AEL-2, at 3; AG 8-30 [rev.] at 3).

Company made adjustments on a rate class basis to account for the deviations of the ten-year average from the 20-year average degree days used to define normal weather (RR-DTE-19 [rev.]; Exhs. DTE 10-18 [rev.]; DTE 2-40 [rev.]; AG 8-30 [rev.]). We find that those adjustments are appropriate and acceptable in this case. Accordingly, the Department finds the Company's method for calculating its weather normalization adjustment is consistent with precedent. Therefore, the Department approves the proposed increase in test year revenues of $5,652,892.

L. Exelon Contract

1. Introduction

Boston Gas proposes a revenue adjustment to account for the loss of a special contract with Exelon New England Holdings, LLC ("Exelon") (Exh. KEDNE/AEL-1, at 9). Boston Gas and Boston Edison Company entered the contract under which the Exelon facilities receive service on April 27, 1995. Under this contract, which has been amended seven times since the initial agreement, Boston Gas provides firm transportation service to two facilities: Exelon New Boston, located in South Boston, and Mystic 7, located in Everett (id.).[13] In March 2003, the Department approved an amendment to the Company's agreement with Exelon that allows Exelon to terminate the agreement with 60 days advance notice, or by March 31, 2004 (id.).

Boston Gas states that its test year revenues include $3.7 million associated with the Exelon contract (id.; Exhs. KEDNE/AEL-2, at 8; AG 6-5). To determine the amount of the

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[13] Amendments to the initial contract were made in November 1995, December 2000, January 2001, February 2001, February 2002, March 2002, February 2003 (Exh. AG 1-99, at 413, 452-458, 461, 463, 466).

proposed revenue adjustment, the Company offset $253,518 in revenue it will gain as a result of a new agreement with Distrigas of Massachusetts ("Distrigas"), beginning March 1, 2002, to transport gas to Exelon's new Mystic 8 and 9 units (Exhs. KEDNE/AEL-1, at 10; KEDNE/AEL-2, at 8; RR-AG-22; Tr. 6, at 618-620). The net result of these two proposed adjustments is $3,446,482 (Exh. KEDNE/AEL-1, at 10).

2. Positions of the Parties

a. Attorney General

The Attorney General urges the Department to reject the revenue adjustment proposed to account for the claimed expiration of the Exelon special contract, arguing that the Company's claimed revenue loss is (1) not known and measurable, and (2) not beyond the normal ebb and flow of customer changes (Attorney General Brief at 34-35, citing Fitchburg Gas and Electric Light Company, D.T.E. 99-118, at 17 (2001); D.T.E. 02-24/25, at 80). First, the Attorney General contends that the loss is not known and measurable because, even though Boston Gas' current contract with Exelon is set to terminate in March 2004, this contract has a long history of amendments to extend its term (id. at 35). Specifically, the Attorney General notes that the initial contract had a termination date of December 1, 2000, but has been extended several times to date (id., citing Exh. AG 1-99, at 413, 452-458, 461, 463, 466). The Attorney General asserts that the Company has not provided convincing evidence that the contract will not be extended again, particularly in light of the fact that the majority of the use under the contract is for the Mystic 7 unit, which will remain in service for

the foreseeable future, and may continue as an interruptible customer (id. at 35-36, n.27, citing RR-AG-25).

In addition, the Attorney General argues that the Company's anticipated revenue loss does not constitute a significant adjustment (id. at 36, citing Tr. 7, at 778; D.T.E. 99-118, at 20 (adjustment allowed where lost customer generated about 8.4 percent of electric base distribution revenues and 20 percent of total electricity demand); D.T.E. 02-24/25, at 80-81 (adjustment allowed where lost customer contributed almost seven percent of base electric distribution revenues)). According to the Attorney General, the Exelon contract revenues Boston Gas stands to lose are about 1.1 to 1.2 percent of the Company's base distribution revenues ($3.7 million divided by $338.6 million) (Attorney General Reply Brief at 24). The Attorney General asserts that a loss of 1.1 to 1.2 percent is well within the boundaries of normal ebb and flow and, therefore, the Department should not allow the proposed revenue adjustment (id. at 25). The Attorney General further notes that Boston Gas is not even losing Mystic Station as a customer, as the Company will continue to provide distribution services for the Mystic 8 and 9 generating facilities through an arrangement with a third-party supplier (Attorney General Brief at 36).

The Attorney General argues that special contract revenues should be (1) treated as offsets to costs rather than contributions to profits, and (2) measured in terms of distribution tariffed rate revenue requirements, not before-tax income (Attorney General Reply Brief at 24). Finally, the Attorney General states that the Department should review the continuing

need for special contracts and determine the best contracting policies and practices in order to develop a single set of standards for all utilities (Attorney General Brief at 38).

b. Boston Gas

Boston Gas asserts that the revenue adjustment for the termination of the Exelon contract is appropriate and consistent with Department precedent because it results in (1) a known and measurable change to test year revenues, and (2) a significant adjustment outside of the normal ebb and flow of customers (Boston Gas Brief at 45-47, citing D.T.E. 02-24/25, at 80; D.T.E. 99-118, at 14, 20; D.P.U. 96-50 (Phase I) at 76). First, the Company states that termination of the Exelon contract represents a known change to its test year revenues because termination of the contract is likely to occur and the Company can determine the revenues it would have received under the Exelon contract (id. at 47, 48).

Boston Gas asserts that termination of revenues associated with the Exelon contract is "highly likely" based on Exelon's actions and, therefore, represents a known change to test year revenues (id. at 47). According to Boston Gas, Exelon has notified the Company that it will not renew the existing contract because it plans to begin operating two new plants in Everett this year (Mystic 8 and Mystic 9) and Exelon has concluded that the New Boston plant cannot physically operate at the same time as the new Mystic 8 and 9 (id.; Exh. KEDNE/AEL-1, at 9). The Company further notes that Exelon has made public pronouncements of its intent to close its New Boston facility, and that the amended agreement allows Exelon to terminate the contract with 60 days notice, even earlier than March 31, 2004 (Boston Gas Brief at 48, citing Exhs. KEDNE/AEL-1, at 10; AG 8-39). In addition, by using

2002 Exelon contract revenues as a proxy for revenues that it would have received under the contract in the future, Boston Gas argues that the loss is measurable (id.).

The Company further argues that the revenues associated with the Exelon contract are significant and outside the normal ebb and flow of customers because (1) they represent approximately 22 percent of the Company's revenues from special contracts, and (2) elimination of these revenues would have a 5.2 percent impact on net operating income before taxes (id. at 48-49, citing Exh. AG 19-12 [confidential]; Tr. 7, at 776).[14] Further, Boston Gas states that the margin associated with the Exelon contract is three-and-a-half times larger than that of the replacement Distrigas contract (id. at 49, citing Exh. KEDNE/AEL-2, at 8; Tr. 7, at 776). Therefore, the Company argues that loss of the Exelon contract is significant and outside of the normal ebb and flow of customers (id.).

3. Analysis and Findings

The Department does not normally make adjustments for post-test year changes in revenues attributed to customer growth unless the change is significant. D.T.E. 02-24/25, at 77; Massachusetts-American Water Company, D.P.U. 88-172, at 7-8 (1989); Bay State Gas Company, D.P.U. 1122, at 46-49 (1982). The rationale for this policy is that revenue adjustments of this nature would also require a number of corresponding adjustments to expense, and could disrupt the relation of test year revenues to test year expenses. New

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[14] The Company calculated that the $3.7 million associated with the Exelon contract, when compared to non-core customer revenues, represents approximately 22 percent of special contract revenues (Boston Gas Brief at 48, citing Exh. AG 19-12 [confidential], Tr. 7, at 776).

England Telephone and Telegraph Company, D.P.U. 86-33-G at 322-327 (1989). However, the addition or deletion of a customer or a change in a customer's consumption, either during or after the test year, that (1) represents a known and measurable increase or decrease to test year revenues, and (2) constitutes a significant adjustment outside of the "ebb and flow" of customers, may warrant a departure from this standard practice. An amount adjusted for may be significant in one set of circumstances and insignificant in another set. In cases where such a change in consumption or customers is found to exist, the Department may include (or exclude) a representative level of sales corresponding to a proven change in deriving a utility's revenue requirement. D.T.E. 02-24/25, at 80; D.T.E. 99-118, at 14-20; D.P.U. 88-172, at 7-9; Western Massachusetts Electric Company, D.P.U. 558, at 70-72 (1981).

First, Boston Gas must demonstrate that the expected revenue loss due to termination of the Exelon contract represents a decrease in test year revenues that is both known and measurable. The Department finds Boston Gas has demonstrated that the anticipated loss is measurable, because the 2002 revenues associated with the Exelon contract can be used as a reasonable proxy for revenues that the Company would receive under the contract in the future (Boston Gas Brief at 48; Exhs. KEDNE/AEL-1, at 9; KEDNE/AEL-2, at 8; AG 6-5). However, the Department finds that the expected revenue loss is not "known," because the Company has not established that termination of the contract is certain. Although the Company states that Exelon may terminate its contract by March 31, 2004, the contract historically has been renewed several times under similar conditions (Exh. AG 1-99, at 413, 452-458, 461, 463, 466). Further, the Department notes that, in order for a generating facility

to be retired, the operator must receive approval from the regional system operator, ISO-NE. See Restated New England Power Pool ("NEPOOL") Agreement, §§ 18.4, 18.5 (October 3, 2001 (as amended)). Regardless of Exelon's stated intentions to shut down the New Boston and Mystic 7 generating facilities, at the time the Company's filing was prepared and presented to the Department, Exelon had not received approval from the ISO-NE to retire the New Boston plant, so far as we know from evidence presented by the Company as part of its proof. In addition, subsequent to the close of the record in September 2003, the NEPOOL reliability committee failed to approve Exelon's application to retire the New Boston facility.[15]

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[15] Among actions taken at the September 2, 2003 NEPOOL reliability committee meeting was a vote for approval of retirement applications for units including Exelon's New Boston plant. The motion failed to pass. Memorandum from Richard Burke, Secretary, ISO New England Inc., NEPOOL Reliability Committee, to NEPOOL Participants Committee, Regarding Actions of the NEPOOL Reliability Committee, at 3 (September 3, 2003); Letter from Stephen G. Whitley, Senior Vice-President and Chief Operating Officer, ISO New England ("ISO-NE"), to Mark Schiavoni, Vice-President, Exelon Power, Northeast Operations (September 9, 2003) ("ISO-NE Letter").

ISO-NE states that the New Boston Station "may be required for NEPOOL System Reliability until vital transmission improvements in the South Shore to Boston Import areas and/or the downtown Boston 115 kV transmission system are completed, or other demand response or generation projects are implemented" (ISO-NE Letter at 1). Therefore, ISO-NE did not approve Exelon's proposed plan to retire New Boston Station for implementation (id.).

As these documents are reliable evidence on matters relevant to this proceeding and within the scope of the Department's specialized knowledge, the Department takes administrative notice of the memorandum and letter pursuant to 220 C.M.R. § 1.10(2). We note, however, that we base our decision here on the record as it stands, absent the NEPOOL reports. See G.L. c. 30A, §11(5). Taking notice of the NEPOOL documents is merely corroborative of the conclusion we draw from the record evidence.

Therefore, the Department finds that the Company has not sufficiently shown that termination of the contract is likely (Boston Gas Brief at 48; Exhs. KEDNE/AEL-1, at 9-10; AG 8-39). Accordingly, we find that although the potential loss associated with the Exelon contract is measurable, because it is not certain to occur it is it is not "known." Therefore, the potential loss cannot be "known and measurable" in the sense that the term has been applied in precedent. See, e.g., D.T.E. 02-24/25, at 80-83; Berkshire Gas Company, D.T.E. 01-56-A at 13-14 (2002); D.T.E. 99-118, at 14-20, and cases cited.

In addition, in order to make an adjustment for post-test year changes in revenues, the Company must also establish that the loss is significant and beyond the normal "ebb and flow" of business. In making the "ebb and flow" determination, the Department has consistently considered the effect on a company's total distribution operating revenues. See D.T.E. 02-24/25, at 80; D.T.E. 99-118, at 18. In this proceeding, Boston Gas argues that the loss is significant because it constitutes 22 percent of special contracts revenues, and 5.2 percent of the Company's net operating income, but the Company makes no reference to total distribution revenues. Total distribution revenues are the standard for comparison – not some subset such as special contracts. See, e.g., D.T.E. 02-24/25, at 80-81. Nor does the Company provide any justification as to why a comparison of the Exelon contract revenues to either of these benchmarks is more appropriate than a comparison to total distribution revenues.

The Department is not persuaded that in these circumstances that such a loss of revenues is significant enough to fall outside normal the ebb and flow of business. See, e.g.,

D.T.E. 02-24/25, at 80-83; D.T.E. 99-118, at 18. The loss, even if experienced (which it may well not be) amounts to only 1.1 percent of total distribution revenues. The Company's attempt to pump up its significance to 22 percent by comparing the contract to the total of special contract revenues distorts the standard and is unconvincing. Therefore, because it is neither known, nor a significant adjustment outside of the normal ebb and flow of customers, the Company's proposed revenue adjustment is denied.

Finally, the Attorney General urges the Department to review special contracts policies and practices in order to develop a single set of standards for all utilities. We note, however, that there already exists a single set of standards that the Department applies in reviewing all special contracts filed by LDCs. See Boston Gas Company, GC03-15 (2003); Bay State Gas Company, GC03-14 (2003); Boston Gas Company, GC03-12 (2003); NStar Gas Company, GC00-16 (2000); Colonial Gas Company, GC00-03 (2000); Commonwealth Gas Company, GC98-3 (1998). This set of precedents is more than enough guidance in this and future rate cases, and so we decline the Attorney General's request.

III. RATE BASE

A. Distribution System Additions

1. Introduction

Since 1996, the Company has invested approximately $565 million in its distribution system (Exhs. KEDNE/PJM-1, at 44; DTE 4-19). Of this amount, approximately $447 million was invested in mains and services designed to (1) expand total throughput,

(2) increase reliability,[16] and (3) comply with state, federal and local regulatory requirements (Exhs. KEDNE/PJM-1, at 44-45; DTE 4-20).[17] The average annual plant investment made by Boston Gas during the years 1996 through 2000 was approximately $55 million (Exh. AG 1-17). In 2001, plant additions totaled approximately $149 million, and were approximately $129 million during the test year (id.).

The Company provided a copy of its system reinforcement plan in effect during the period 1995 through 2005 (Exh. DTE 4-23). The Company indicated that the design day level and throughput requirements in its distribution system plan is in accordance with the cost benefit analysis and design day and design year planning standards approved in its long range and resource requirements plan (Exh. DTE 4-37). Boston Gas states that as a result of the use of its engineering software, the Company was able to identify and reinforce approximately 1,500 areas on its system where low pressures could be expected during design conditions, which resulted in the number of points in its system with predicted pressures below design day levels falling to zero, and only two pressure-related outages affecting four customers during the unusually cold winter of 2002-2003 (Exh. KEDNE/JFB-1, at 9-10).

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16 The Company estimated that its cast-iron replacement costs, as a percentage of its total annual reliability spending, was 21.4 percent during 1995, 20.2 percent during 1996, 13.87 percent during 1997, 19.4 percent during 1998, 21.8 percent during 1999, 25.9 percent during 2000, 28.6 percent during 2001, and 31.7 percent during 2002 (RR-DTE-96).

17 The $447 million consists of the following: (1) $176.4 million for expansion; (2) $195.4 million for reliability; and (3) $75.4 million for compliance to regulatory requirements (Exh. DTE 4-21).

2. Positions of the Parties

a. Attorney General

The Attorney General alleges that Boston Gas spent millions of dollars "loading the test year" with capital additions, approximately doubling test year spending on plant additions as compared to the period 1996-2000 (Attorney General Brief at 3; Attorney General Reply Brief at 4-6, citing Exhs. AG 1-17; DTE 4-16; DTE 4-43).[18] Specifically, the Attorney General maintains that in the years prior to 2002, the Company allowed its distribution system to decline, such that there was inadequate system pressure on more than 1,500 streets (Attorney General Brief at 2-3; Attorney General Reply Brief at 5). As a result, the Attorney General contends that Boston Gas was forced to spend millions of dollars to bring its distribution system up to acceptable standards (Attorney General Brief at 3).

Further, the Attorney General asserts that the Company failed to maintain the output of its engineering system simulations in violation of the Department's records retention regulations in 220 C.M.R. § 75.00 et seq., thereby warranting a negative inference by the Department as to the Company's system maintenance practices (Attorney General Reply Brief at 5). The Attorney General argues that any and all costs to rehabilitate Boston Gas' distribution system should be borne by the Company's shareholders, and not ratepayers (Attorney General Brief at 3).

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[18] The Attorney General requests that the Department incorporate by reference or take administrative note of the gas plant additions information contained in the Company's annual returns to the Department for the years 1996 and 1997 (Attorney General Reply Brief at 5, n.2, citing 220 C.M.R. §§ 1.10(2), 1.10(3))

The Attorney General asserts that Boston Gas delayed its capital investments between 1995, the test year associated with the Company's last rate case, and 2002, for the purpose of ensuring that end of the selected test year would have a maximum level of undepreciated capital investments in rate base (Attorney General Reply Brief at 5). As a result of this delay in capital investment, the Attorney General contends that the Company's net plant in service is higher than what would have normally been expected because of the lower-than-normal accumulation of depreciation and associated deferred income taxes, thus producing higher rates for consumers (id.).

In order to adjust for what the Attorney General characterizes as the Company's "attempt to frustrate the purpose of incentive ratemaking," the Attorney General calculates that, had the Company made its capital investments on a more consistent basis over the years 1996 through 2002, Boston Gas' books would be presently carrying additional depreciation reserves of approximately $24,000,000 (id. at 6, n.3). Therefore, the Attorney General proposes that this amount, as well as the associated accumulated deferred income taxes, should be deducted from the Company's rate base (id.). The Attorney General considers his proposal to produce a reasonable level of rate base for Boston Gas (id. at 6).

b. Boston Gas

Boston Gas maintains that its system investments made in recent years are necessary and appropriate (Boston Gas Reply Brief at 8). The Company acknowledges that it has increased distribution system investments in recent years. The Company argues that the fact that its investments have increased in recent years does not constitute evidence of an intent to

"load the test year" with rate base additions (id.). Instead, the Company maintains that the significant increases in capital spending in recent years resulted from its commitment to safety and reliability as well as growth (id.). Boston Gas states that because Keyspan is a much larger company than the Company's previous parent, Eastern Enterprises, Keyspan has greater resources available to meet the Company's capital system demands (id. at 8-9, citing Tr. 22, at 2927-2928). Moreover, Boston Gas contends that Keyspan's commitment to maintain system reliability and achieve the benefits resulting from system expansion has been demonstrated and will continue throughout the term of the Company's PBR plan (id. at 9, citing Exhs. KEDNE/JFB-1, at 8-9; AG 1-2B(1)(a) at 8; AG 1-18; Tr. 22, at 2927).

Boston Gas contends that the Attorney General's analysis of the Company's plant additions is flawed because the Attorney General's data for 2001 includes approximately $39 million in intangible plant, and that the plant additions reported for 2000 is actually $64 million (Boston Gas Reply Brief at 9-10). The Company states that the plant additions data provided in the annual returns to the Department for the period 1991 through 2002 demonstrate that investment levels during this time were consistent with the levels committed to by Eastern Enterprises during the term of the Company's first PBR plan (id. at 10-11).[19]

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[19] Boston Gas requests that, if the Department grants the Attorney General's request to incorporate by reference information from the Company's 1996 and 1997 Annual Returns to the Department, the Department also incorporate by reference or take administrative notice of the same information for the years 1990 through 1995 (Boston Gas Reply Brief at 10, n.4). In the interest of completeness, the Department will incorporate the Company's Annual Returns to the Department for the years 1990 through 1995 into the record by reference. 220 C.M.R. §§ 1.10(2), 1.10(3).

The Company defends its use of its engineering software, stating that the modeling allowed Boston Gas to run simulations under design conditions to identify specific locations where pressure problems could be expected to occur (id. at 12-13, citing Tr. 12, at 1485-1487, 1522-1528; RR-AG-76). The Company maintains that the Attorney General's claim that the Company destroyed, lost or failed to retain the system modeling reports misconstrues the nature of computer simulation, and that the lack of records for the years prior to 2000 can not be reasonably construed as a failure to maintain adequate records (Boston Gas Reply Brief at 12-13).

The Company argues that in addition to the lack of record support for the Attorney General's position, the Attorney General has provided no legal basis for his proposed adjustment (id. at 13-14). Boston Gas contends that in order for the Department to grant the Attorney General's request, a finding that the Company's investment was imprudent would be required (id. at 14). With the exception of specific projects identified by the Attorney General, Boston Gas maintains that the Attorney General has made no claims of imprudence in the Company's system investments, and that the Attorney General has made no factually or legally sufficient argument to warrant any cost disallowance, much less the one he has proposed (id. at 14).

3. Analysis and Findings

Rate base is determined according to the cost of the utility's plant in service as of the end of the test year. D.T.E. 02-24/25, at 22; D.P.U. 96-50 (Phase I) at 15; Western Massachusetts Electric Company, D.P.U. 85-270, at 20 (1986). Year-end plant in service is

included in rate base if the expenditures are prudently incurred and the resulting plant is used and useful in providing service to ratepayers. D.T.E. 02-24/25, at 22; D.P.U. 96-50 (Phase I) at 15. Although the Attorney General has not proposed to reduce the Company's plant in service, his proposal to increase in the Company's depreciation and deferred income taxes reserves to correct what he considers to be abnormally high plant increases in recent years produces the same outcome.

The Company's annual mains and services expenditures related to meeting safety and reliability requirements were $34.6 million during 1995, $32.2 million during 1996, $31.1 million during 1997, $31.8 million during 1998, $26.6 million during 1999, $40.4 million during 2000, $55.2 million during 2001, and $53.5 million during 2002 (Exh. DTE 4-16).[20] During that same period, the Company's annual mains and services expenditures related to meeting additional growth-related demand was $18.5 million during 1995, $14.7 million during 1996, $18.9 million during 1997, $21.3 million during 1998, $19.5 million during 1999, $27.8 million during 2000, $34.5 million during 2001, and $39.7 million during 2002 (id.). A company's capital expenditures would be expected to vary from year to year, subject to certain bounds (Tr. 22, at 2931). Therefore, the fact that the Company's capital expenditures have increased in recent years is an insufficient basis to conclude that Boston Gas has timed its rate base additions for maximum benefit in a rate case.

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[20] Because Keyspan acquired Boston Gas in November of 2000, near the end of the construction season, the Company's system improvements during 2000 were, for all intent and purposes, made under the ownership of Eastern Enterprises.

In Boston Gas Company, D.P.U. 88-67 (Phase I) at 172-173, the Department faulted the Company for the "evident lumbering pace" of its cast-iron main replacement program.[21] The importance of replacing cast-iron mains is critical for safety reasons. See Pipeline Engineering and Safety Division, Re 8 Ashton Street, Dorchester (January 19, 2000). Since that time, the Company has worked in conjunction with the Department's Pipeline Engineering and Safety Division to accelerate the replacement of its cast-iron mains, increasing the annual miles of actual replacement from approximately 5.8 miles per year in 1987 to 27.9 miles during 2002 (Exh. DTE 4-43). The Company's cast-iron main replacement program includes both actual main replacements and relaying, including the relaying of 30,000 feet of cast-iron mains with plastic during the test year (Exh. KEDNE/PJM-1, at 50). Recently, the Company has embarked on a program to resolve the problem of mains encroachment,[22] and has agreed to increase its spending and resources employed in this area (Tr. 22, at 2928-2929). See also Boston Gas Company, D.T.E. 01-PL-30 (2002); Boston Gas Company, D.T.E. 01-PL-27 (2002). Because of Keyspan's status as a multi-state holding company, Boston Gas has a greater level of capital resources available to it for system investments (Tr. 22, at 2927-2928). Moreover, Keyspan has expressed a commitment to maintain Boston Gas' system reliability

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[21] Cast-iron pipe represents the oldest components of the Company's distribution system. As one of the oldest gas distribution systems in the United States, Boston Gas has a higher proportion of cast-iron mains than would systems of more recent vintage. The age and fragility of cast-iron mains, especially small-diameter ones, results in their being prone to breakage. D.P.U. 88-67 (Phase I) at 168.

[22] Because cast-iron mains eight inches or less in diameter are susceptible to stress fractures from nearby excavations, these types of mains must be replaced immediately if the nearby excavation meets specified conditions. 220 C.M.R. §§ 113.06, 113.07.

while expanding the Company's infrastructure (Exh. KEDNE/JFB-1, at 8-9; Tr. 22, at 2932-2933). Boston Gas can not be fairly faulted for its efforts to ensure the safety and integrity of its distribution system.

While the Attorney General points to the fact that Boston Gas did not retain the original modeling simulations it developed from the engineering model as evidence that the results of the Company's engineering analysis can not be relied upon, this represents an unproven assertion. The Department recognizes that the engineering software constitutes a computer network tool used on a regular basis to evaluate gas utility infrastructure performance under simulated conditions (Tr. 12, at 1523-1525). The model runs prepared by the software do not constitute reports, and thus do not constitute records subject to the Department's retention policies promulgated pursuant to 220 C.M.R. § 75.00 et seq. Additionally, while the Attorney General makes a point worth considering that it is improbable that approximately 1,500 streets simultaneously would experience low pressure conditions, he has overdrawn the point by presuming without proving that the Company was aware of the low-pressure conditions. Rather, the Department construes the evidence as signifying that the low-pressure conditions were not identifiable until the adoption of the Company's engineering model.

The increase in system investment is evidence that the new ownership is taking its safety operations obligations with reemphasized seriousness. The Department does not judge Keyspan's renewed vigor in investment in safety-related plant by a standard drawn from the investment behavior of its predecessor which the Department has been encouraging since D.P.U. 88-67 to renew the physical plant. It appears that Keyspan has taken the direction of

D.P.U. 88-67 and the lessons from the Ashton Street incident seriously. Moreover, much of the investment represents preparation of a new based for future growth, and the Department does not wish to discourage this potential for growth by disallowing renewed investment in system operations improvements and customer safety. Based on the above considerations, the Department finds no basis to conclude that the Company systematically timed its system improvements to achieve the maximum benefit to rate base from plant additions. Therefore, the Department declines to adopt the Attorney General's proposed reduction to the Company's depreciation and deferred income tax reserves.

B. Revenue-Producing Plant Additions

1. Introduction

Revenue-producing plant additions, also referred to as growth-related plant, are additions to meet new or incremental customers' load. Boston Gas provided the project number, location, description, amount of investment, and the post-construction internal rate of return ("IRR") for 83 revenue-producing distribution projects completed between 1996 and 2002 with costs in excess of $100,000 (Exhs. KEDNE/PJM-1, at 45; KEDNE/PJM-10). The individual post-construction IRRs for each of these projects range from negative seven percent to a positive 125 percent (Exh. KEDNE/PJM-10). Boston Gas also provided the total annual capital investment on distribution system growth for the years 1996 through 2002, which indicated total annual IRRs ranging from 18.0 percent in 2000, to 28.0 percent in 1999 (Exhs. KEDNE/PJM-1, at 45; KEDNE/PJM-9). The Company evaluates IRR thresholds for project initiation annually, taking into consideration competing capital requirements across the

Keyspan system (Exh. DTE 4-28; Tr. 7, at 814-815). The Company's current IRR thresholds are 11.75 percent for residential revenue-producing capital investments and 12.75 percent for commercial and industrial ("C&I") revenue-producing capital additions (Exh. DTE 4-28; Tr. 7, at 814-816).

2. Positions of the Parties

a. Attorney General

The Attorney General argues that the Department should exclude from rate base at least 16 revenue-producing plant additions with a total cost of $5,941,000, because these projects have IRRs that are less than the Company's weighted average cost of capital ("WACC") of 9.38 percent approved in its last rate case, D.P.U. 96-50 (Attorney General Brief at 26-27; Attorney General Reply Brief at 17).[23] Further, the Attorney General argues that if Boston Gas' IRR thresholds for revenue-producing project initiation were used (11.75 percent for residential, 12.75 percent for C&I), an additional 18 revenue-producing projects, with a total cost of $7,425,088, should be eliminated from rate base (Attorney General Brief at 26, n.19, citing Exhs. KEDNE/PJM-10; DTE 4-28; Tr. 7, at 815).[24] In total, the Attorney General

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[23] The Attorney General identifies the associated project work order numbers as: 625W, 48652, 46888, 122285, 194128, 38492, 102877, 126093, 153427, 170308, 181446, 194601, 211000, 214674, 215994, and 257507 (Attorney General Brief at 26, citing Exh. KEDNE/PJM-10).

[24] Although the Attorney General refers to ten additional projects in his brief, he identifies the work orders of eighteen total projects as having IRRs lower than the Company's thresholds for revenue producing project initiation of 11.75 percent for residential projects and 12.75 percent for C&I projects: 952Q, 620U, 28507, 31443, 42648, 57965, 75948, 78752, 65725, 68904, 101932, 106700, 168829, 169744, 169907,

(continued…)

argues that revenue-producing projects totaling $13,366,000 should be excluded from rate base.

The Attorney General notes that Boston Gas has represented that, prior to the start of a prospective capital investment, the Company evaluates the project to determine whether the project will yield a rate of return higher than the return allowed in its last rate case (Attorney General Brief at 26, citing Tr. 7, at 814). The Attorney General argues that in contravention of its own stated policy, Boston Gas improperly (1) invested in growth-related projects where the Company did not expect to earn a return greater than its cost of capital, and (2) included the expenses of those growth-related projects in the rate base, regardless of their expected return on investment (Attorney General Brief at 26, citing Exhs. KEDNE/PJM-10; AG-13, AG-27 through AG-38). The Attorney General argues that shareholders, not ratepayers, should pay for the Company's uneconomic decisions (Attorney General Brief at 25).

In addition, the Attorney General argues that Boston Gas did not provide any support for its claim that (1) the pre-construction IRR for each of the 16 projects exceeded 9.38 percent, and (2) the cost increases for these 16 projects could not have been foreseen at their outset (Attorney General Reply Brief at 17, citing Exhs. KEDNE/PJM-10; DTE 4-31; RR-AG-59). The Attorney General asserts that Boston Gas "inexplicably failed" to provide the initial IRRs that it relied on in deciding to pursue these revenue producing plant additions, and instead provided its post-construction IRRs for these projects (Attorney General Reply

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[24] (…continued)
199770, 200021, and 93010 (Attorney General Brief at 26, n.19, citing Exh. KEDNE/PJM-10).

Brief at 17). The Attorney General states that it is the initial IRR, not the post-construction IRR, that is critical to any Department evaluation of the prudence of these projects (id.). The Attorney General argues that Boston Gas' failure to provide the initial IRRs prevents the Department from determining whether the Company's decisions to invest in these 16 plant additions were reasonable and prudent (id., citing D.T.E. 02-24/25, at 36).[25]

b. Boston Gas

Boston Gas argues that it has met the Department's standard for the inclusion of revenue-producing investments in rate base (Boston Gas Brief at 23, Boston Gas Reply Brief at 37). Boston Gas argues that the Department must evaluate whether the utility's actions, based on all the information that the utility knew or should have known at the time the investment was made, were reasonable and prudent (Boston Gas Brief at 23). In addition, the Company argues that the determination of prudence may not be made on the basis of hindsight, and that it is not appropriate for the Department to substitute its best judgment for the judgment exercised by utility management (id. at 23-24, citing D.P.U. 93-60, at 24; Attorney General v. Department of Public Utilities, 390 Mass. 208, 229 (1983)). Boston Gas argues that the Department allows the inclusion of revenue-producing projects in rate base with a negative IRR or an IRR below the company's WACC, provided that the company

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[25] The Attorney General claims that record request AG-59, which Boston Gas cites to support its contention that each of the 16 projects were justified, addresses only twelve of the 16 challenged projects (Attorney Reply Brief at 16, n.10). The Attorney General states that, even if the Department were to accept Boston Gas' explanation for the failure of the projects to meet the 9.38 percent return threshold, the Company has not provided any explanation for the cost overruns on four plant additions, totaling $1,486,880 (id.).

demonstrates that the actual costs of the project were greater than anticipated due to circumstances not foreseen at the time the project costs were estimated and initiated (Boston Gas Brief at 24, citing Colonial Gas Company, D.P.U. 84-94, at 4-6 (1984); D.P.U. 96-50 (Phase I) at 23-24).

Boston Gas states that it has demonstrated the reasons for the post-estimation cost increases for each of the projects referenced by the Attorney General (Boston Gas Brief at 24, citing RR-AG-59).[26] Boston Gas claims that, for each project, the IRR based on estimated costs was greater than the Company's WACC of 9.38 percent (Boston Gas Brief at 24). In addition, the Company argues that the additional costs incurred during the construction process could not have been foreseen by management (id.). Boston Gas claims that the Attorney General does not contest the Company's cost estimation process, the calculations of the IRRs, or the costs increases which were encountered, but only argues that IRRs fell below the WACC upon project completion (id., citing Attorney General Brief at 26-27). Boston Gas asserts that this is an insufficient basis for the Department to exclude the costs of those projects from rate base (Boston Gas Brief at 24-25). Boston Gas emphasizes that, at the time investments were made, the Company determined that these projects in question would have provided a return in excess of the WACC, and, therefore, that the Company's decision to

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[26] Record request AG-59 provides the supporting calculations for the post-construction IRRs for work order numbers 625W, 620U, 48652, 46888, 122285, 126093, 170308, 194601, 211000, 214674, 257507, and 93010/121927 and discussed the cost overruns associated with ten of these twelve projects.

commence the project was reasonable in the light of the circumstances that then existed (id. at 25).

Boston Gas argues that the Attorney General has failed to cite any Department regulation, precedent, or ratemaking practice that requires the Company to present pre-construction IRRs as part of its initial filing (Boston Gas Reply Brief at 34-35). Boston Gas asserts that, on the contrary, post-construction IRRs are relied on by the Department to determine whether an investment is reasonable and prudent (id. at 34-35, citing D.P.U. 96-50 (Phase I) at 18).[27]

For revenue-producing projects, the Company uses a threshold IRR of 11.75 percent for residential projects and 12.75 percent for C&I projects, which criteria exceed the WACC of 9.38 percent established in D.P.U. 96-50 (Boston Gas Reply Brief at 36, citing Tr. 7, at 814-816).[28] Boston Gas argues that, because the Company will not make an investment if the

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[27] Boston Gas argues that the Attorney General misrepresents the Company's burden of proof in this proceeding, claiming that the burden of production imposed on a proposed rate increase is generally met through its initial filing (Boston Gas Reply Brief at 25, citing D.T.E. 99-118, at 34). Boston Gas argues that its initial filing shifts the burden of production to the Attorney General or other intervenors to submit evidence to rebut Boston Gas' initial case (id.). Boston Gas asserts that, in this case, it provided as part of its initial filing, the post-construction IRRs for all revenue-producing investments in the years 1996 through 2002 exceeding $100,000, including the 16 projects referenced by the Attorney General (Boston Gas Reply Brief at 35, citing Exh. KEDNE/PJM-10). Boston Gas claims that neither the Attorney General nor any other intervenor requested that the Company produce pre-construction IRR calculations for the projects in question (Boston Gas Reply Brief at 34-36, citing Attorney General Reply Brief at 17, Tr. 7, at 819-821).

[28] The Company uses different IRR thresholds for residential and C&I projects because it argues that residential customers tend to be more stable over a longer time than C&I customers (Tr. at 7, at 815).

estimated pre-construction rate of return of a project does not exceed the Company's IRR threshold, by definition, the record establishes that the pre-construction IRRs of the 16 projects would well exceed the 9.38 percent WACC that the Attorney General claims is as necessary to ensure that the investment was reasonable and prudent at the time the decision was made (Boston Gas Reply Brief at 36, citing Tr. 7, at 816). Boston Gas adds that, even if the production of pre-construction IRRs were a requirement to meet the Department's standard, the Attorney General has produced no evidence to contradict the Company's statements that it would not have commenced the 16 projects had those projects had a pre-construction IRR of less than 11.75 for residential projects or 12.75 percent for C&I projects (Boston Gas Reply Brief at 36).

Finally, Boston Gas disputes the Attorney General's claim that the Company has failed to meet its burden of demonstrating that the cost increases could not have been foreseen at the outset of the projects (id.). Boston Gas argues that it has provided all necessary documentation of the construction costs, including capital authorization and closed work order reports, and provided the required cost-benefit analyses for revenue-producing projects in excess of $100,000 (id. at 36-37, citing Exhs. KEDNE/PJM-10; AG-1-19(a); D.P.U. 96-50 (Phase I) at 17-18). Boston Gas claims that it has adequately explained the reasons for the cost increases on the specific projects in question and that the evidence supports a finding that the Company has acted prudently in moving forward with these projects (Boston Gas Reply Brief at 37, citing RR-AG-59).

3. Analysis and Findings

a. Introduction

For costs to be included in rate base, the expenditures must be prudently incurred and the resulting plant must be used and useful to ratepayers. D.P.U. 85-270, at 20. The prudence test determines whether cost recovery is allowed at all, while the used and useful analysis determines the portion of prudently incurred costs on which the utility is entitled to a return. Id. at 25-27.

A prudence review involves a determination of whether the utility's actions, based on all that the utility knew or should have known at that time, were reasonable and prudent in light of the extant circumstances. Such a determination may not properly be made on the basis of hindsight judgments, nor is it appropriate for the Department merely to substitute its own judgment for the judgments made by the management of the utility. 390 Mass. 208, 229. 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 reasonable should have been known at the time a decision was made. D.P.U. 93-60, at 24-25; D.P.U. 85-270, at 22-23; Boston Edison Company, D.P.U. 906, at 165 (1982). A review of the prudence of a company's actions is not dependent upon whether budget estimates later proved to be accurate but rather upon whether the assumptions made were reasonable, given the facts that were known or that should have been known at the time. Massachusetts-American Water Company, D.P.U. 95-118, at 39-40

(1996); D.P.U. 93-60, at 35; Fitchburg Gas and Electric Light Company, D.P.U. 84-145-A at 26 (1985).

The Department has also found that a gas utility need not serve new customers in circumstances where the addition of new customers would raise the cost of gas service for existing firm ratepayers. D.P.U. 88-67 (Phase I) at 282-284. The Department stated that existing customers receive benefits whenever, all other things being equal, the return on incremental rate base exceeds the Company's overall rate of return. Boston Gas Company, D.P.U. 89-180, at 16-17 (1990).

The Department has cautioned utility companies that, as they bear the burden of demonstrating the propriety of additions to rate base, failure to provide clear and cohesive reviewable evidence on rate base additions increases the risk to the utility that the Department will disallow these expenditures. Massachusetts Electric Company, D.P.U. 95-40, at 7 (1995); D.P.U. 93-60, at 26; D.P.U. 92-210, at 24; see also Massachusetts Electric Company v. Department of Public Utilities, 376 Mass. 294, at 304 (1978); Metropolitan District Commission v. Department of Public Utilities, 352 Mass. 18, at 24 (1967). In addition, the Department has stated that:

> In reviewing the investments in main extensions that were made without a cost-benefit analysis, the Company has the burden of demonstrating the prudence of each investment proposed for inclusion in rate base. The Department cannot rely on the unsupported testimony that each project was beneficial at the time the decision was made. The Company must provide reviewable documentation for investments it seeks to include in rate base.

D.P.U. 92-210, at 24 (1993).

The Attorney General challenges the inclusion in rate base of the following two categories of revenue-producing projects: (1) revenue-producing plant additions with post-construction IRRs less than the Company's WACC of 9.38 percent; and (2) revenue-producing plant additions with post-construction IRRs greater than the WACC of 9.38 percent, but less than the Company's internal thresholds for revenue-producing project initiation (11.75 percent for residential, 12.75 percent for C&I). Each category is discussed below.

b. Projects With Post-Construction IRRs Lower than Weighted Average Cost of Capital

Sixteen projects completed by Boston Gas between 1996 and 2002 had post-construction IRRs that were less than the Company's current WACC of 9.38 percent (Exh. KEDNE/PJM-10; DTE 4-31; RR-AG-59). In these instances, the Department will look at Boston Gas' decision to embark on these particular projects and the underlying reasons why the post-construction IRRs failed to meet the Company's 9.38 WACC threshold. D.P.U. 96-50 (Phase I) at 23-24. Of these 16 projects, the Department has examined the street main authorizations ("SMAs") and closing reports for 15 projects.[29]

The SMAs for the following four projects fail to indicate that any pre-construction IRR was calculated or that any other cost-benefit analysis was performed: (1) Walnut Street in Lynnfield (work order number 48652); (2) Tremont Street in Boston (work order number 126093); (3) Salem Street in Lynnfield (work order number 211000); and (4) Hill Top Drive,

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[29] The Company did not include the SMA and closing report for one project (work order number 194128). This project is also discussed, below.

Beverly (work order number 214674) (Exhs. AG-29, AG-32, AG-35, AG-36).[30] In addition, the Walnut Street, Tremont Street, and Salem Street projects do not contain any approval signatures (Exhs. AG-29, AG-32, AG-35). Although the Hill Top Drive project was approved on October 9, 2001, the SMA for this project shows a zero projected load with a corresponding projected gross margin of zero dollars (Exh. AG-36). The closing costs of these four projects totaled $1,197,851 (Exhs. AG-29, AG-32, AG-35, AG-36).

Based on the estimated total investments shown in the SMAs and the closing reports that accompany those SMAs, the cost overruns of each of these four projects were: (1) $101,323, or 129 percent, for the Walnut Street project; (2) $450,580, or 374 percent, for the Tremont Street project; (3) $205,236, or 188 percent, for the Salem Street project; and (4) $57,307, or 76 percent, for the Hill Top Drive project (id.). Although the Company provided explanations for the large cost overruns for each of these four projects (see RR-AG-59), the Company has not provided any basis for the Department to evaluate whether the Company's threshold decision to invest in these four projects was prudent at the outset. As state above, the Department has found that a gas utility is not required to serve new

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[30] The Company's existing SMA form includes sections that specify the following: (1) the work order number and description of the main to be installed; (2) any associated services required for installation and cost estimate; (3) projected load broken down into types of load and the gross margin expected to be generated; (4) estimate of total investments broken down into direct and indirect costs; (5) general comments on the project; and (6) approvals at different levels of Company management. See Exhs. AG-30; AG 1-19. The existing SMA form does not include a section that requires calculation of the project's pre-construction IRR (id.). The Company currently estimates the indirect cost of a project to be equal to 45 percent of project's direct cost (id.; see D.P.U. 96-50 (Phase I) at 17).

customers in circumstances where the addition of new customers would raise the cost of gas service. D.P.U. 88-67 (Phase I) at 282-284. Thus, a pre-construction IRR is prerequisite to a utility's decision whether to invest in a revenue-producing plant as a basis to ensure that its decision to serve new customers will not raise the cost of service to existing ratepayers. In addition, the Department has warned utility companies that they bear the burden of demonstrating the propriety of additions to rate base, and that a failure to provide clear and reviewable evidence regarding rate base additions increases the risk that the Department will reject these expenditures. D.P.U. 95-40, at 7; D.P.U. 93-60, at 26; see also 376 Mass. 294, at 304; 352 Mass. 18, at 24.

Prudence in decision-making as a prerequisite to recovery in rates implies the sound exercise of judgment and foresight. The best evidence of prudence is documentation of the decision-making before the decision is taken, even where, in the event, the decision proves cost-ineffective. Put differently, thorough and clear, contemporaneous documentation that analyzes and supports as cost-justified a decision yet to be taken, goes a long way toward underpinning the prudence of the decision, once taken, irrespective of its outcome in the actual event. But where a want of contemporaneous documentation of the decision appears, compensating for that want by after-the-fact, "analytic" justification of a decision (especially a decision with an adverse outcome) is far less persuasive.

Boston Gas argues that it was not required to show pre-construction IRRs as part of our standard. However, the burden of proof is on Boston Gas to demonstrate that its investments

are prudent.[31] Boston Gas contends that it will not invest in revenue producing plant additions if the project's estimated pre-construction rate of return does not exceed the Company's own IRR threshold (i.e., 11.75 percent for residential projects and 12.75 percent for C&I projects) which is above the Company's WACC of 9.38 percent (Tr. 7, at 816). Thus, the Company argues that "by definition," the record establishes that pre-construction IRRs of its revenue producing projects would "well exceed the 9.38 percent [WACC]" (Boston Gas Reply Brief at 36). Boston Gas' argument, by itself, insufficient for the Department to determine that the investment was reasonable and prudent at the time the decision was made. This question-begging argument assumes what is to be proved about each decision, namely its prudence. As we have stated in D.P.U. 92-210, at 24, the Department cannot rely on unsupported testimony that each project was beneficial at the time the decision was made. The Company has failed to provide reviewable documentation for these investments it seeks to include in rate base. It may be an exaggeration, but the old saw, "the faintest writing may be more vivid than the clearest memory," has much to recommend it. Therefore, the Department finds that these four projects do not meet the Department standard for plant addition to rate base. Accordingly, the Department will exclude from rate base the entire cost of these four projects, for a total of $1,197,851.[32]

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[31] The burden of proof is the duty imposed on a proponent of a fact whose case requires proof of that fact to persuade the fact finder that the fact exists, or where a demonstration of non-existence is required, to persuade the fact finder of the non-existence of that fact. D.T.E. 01-56-A at 16; D.T.E. 99-118, at 7.

[32] The total amount of $1,197,851 is the sum of: $179,888, $571,167, $314,493 and

(continued…)

Regarding the project associated with Brockton Avenue, Abington (work order number 257507), the SMA describes an extension of 1,300 feet of four-inch main on Brockton Avenue plus an additional 500 feet of two-inch pipe on High Street to a new subdivision (Exhs. AG-37, at 1; AG 1-19, Att. AG 1-19(a)). The estimated total cost of the project was $81,987, of which $56,543 represented the Company's direct costs (id.). The projected annual load was 472 thousand cubic feet ("Mcf") (id.). No preconstruction IRR was computed or any cost benefit analysis performed, except that the expected average margin was estimated to be $3.61 per Mcf, resulting in a projected annual gross margin contribution of $1,704 ($3.61 times 472) (id.). The closing report accompanying the SMA shows a project completion cost of $182,326, resulting in a cost overrun of $100,339, or 122 percent for the Brockton Avenue project (id. at 1, 7).

The expected payback period for the Brockton Avenue project, using the $81,987 pre-construction estimated costs, would have been 48 years ($81,987 divided by $1,704). This period is almost twice as long as the 25-year (2002 to 2026) payback period used by the Company in calculating the six percent post-construction IRR for this project (see Exh. KEDNE/PJM-10; AG-RR-59(11)). Although the Company provided explanations for the

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[32] (…continued)
$132,303 and is based on the closing reports for work order numbers 48652, 126093, 211000, and 214674, respectively (Exhs. AG-29, AG-32, AG-35, AG-36). There is a difference of $44,872 from the total costs of these four projects based on the Company's filing, attributable to work order number 48652, which shows a completion cost of $179,888 based on the closing report, compared to $135,016 shown in Exhibit KEDNE/PJM-10, at 1. We relied on the closing report to derive the final amount (Exh. AG-29, at 6).

122 percent cost overrun for the Brockton Avenue project (see RR-AG-59(11)), the Company's pre-construction estimate does not provide an economic justification for undertaking this project. Therefore, the Department finds that the Company's decision to initiate this project was not prudent. Accordingly, the Department will exclude from rate base the entire cost of this project, for a total of $182,326.

Regarding the projects associated with Kemp Street, South Boston (work order number 38492) and Russell Street, Watertown (work order number 102877), the SMAs for each of these projects demonstrate that the Company provided adequate economic justifications for starting these projects. The Company calculated a pre-construction IRR of 87.5 percent for the Kemp Street project, with an estimated investment cost of $257,185, and performed gross margin analysis for the Russell Street project with an estimated investment cost of $162,940 (Exh. AG 1-19, Att. AG 1-19 (a)). The completion costs of these two projects are $674,937 and $282,851, respectively, resulting in a cost overruns of $417,752, or 162 percent, and $119,910, or 74 percent, respectively (id.). Despite these cost overruns, which resulted in post-construction IRRs that fell below its WACC, the Company did not provide any evidence regarding its cost-containment efforts with respect to these projects. While these mains are used and useful, and the Company provided economic analyses and justification prior to project initiation, the Department finds Boston Gas failed to provide any explanation for the cost overruns. Therefore, the Department will exclude from rate base the costs that were incurred in excess of the Company's original project cost estimates. Accordingly, the Department will exclude from rate base $417,752 associated with the cost overrun for the

Kemp Street project and $119,910 associated with the cost overrun for the Russell Street project. D.P.U. 95-118, at 49-55.

The new mains installed in (1) Quarry Street, Quincy (work order number 153427), (2) Northend Street, Peabody (work order number 181446), and (3) Prospect Street, Leominster (work order number 215994) had an estimated combined project cost of $1,379,531, and a combined completed cost of $1,209,930 (Exh. AG 1-19, Att. AG 1-19 (a)). The SMAs for these projects show that the Company performed gross margin analyses for each project, calculated a pre-construction IRR of 11.71 percent for the Peabody project, and indicated the levels of anticipated load growth for the Quincy project (Exh. AG-1-19, Att. AG 1-19 (a)). These analyses are adequate economic justifications for project initiation.

The closing reports for each of these three projects do not indicate any cost overruns based on each project estimated total cost. The Department has allowed gas companies to include anticipated growth in their estimates of the benefits to be realized on the incremental rate base required to serve new customers. See D.P.U. 96-50 (Phase I) at 23; D.P.U. 93-60; D.P.U. 92-210, at 23; D.P.U. 84-94, at 6. Based on these considerations, the Department finds that these projects are prudently incurred and are used and useful. Accordingly, the Department allows the Company to include the costs of these projects in rate base.

With respect to the following five projects: (1) West Main Street, Shirley (work order number 625W); (2) Nevin Street, Brighton (work order number 46888); (3) Jackson Drive Extension, Acton (work order number 122285); (4) Stonecroft Court, Weston (work order number 170308); and (5) Woburn Lake Avenue, Woburn (work order number 194601), the

SMAs show that the Company performed gross margin analyses for all projects, calculated a payback period of 4.7 years for the West Main Street project, and calculated a pre-construction IRR of 13.0 percent for the Jackson Drive Extension project which exceeded the Company's WACC of 9.38 percent (Exh. AG-1-19, Att. AG 1-19 (a)). These analyses are adequate economic justifications for project initiation. Based on the total pre-construction cost estimate of each project and its corresponding completion cost, the cost overruns are: (1) $677,592, or 253 percent, for the Nevin Street project; (2) $104,742, or 217 percent, for the Jackson Drive Extension project; (3) $54,659, or 83 percent, for the Stonecroft Court project; and (4) $96,768, or 210 percent for the Woburn Lake Avenue project (Exhs. AG 1-19, Att. AG 1-19 (a); AG-27, AG-30, AG-31, AG-33, AG-34). The West Main Street project had a cost overrun of $57,571, or eleven percent (Exh. AG-27). The Company provided explanations for the cost overrun of each project, which included additional main installations, ledge conditions, roadway reconstruction, additional trenching expenses, main relay system reinforcement, and permitting requirements (RR-AG-59). The Department finds that the Company has adequately explained the cost overruns. Accordingly, the Department allows the Company to include in rate base the total cost of these projects.

The remaining project, located in Boston (work order number 194128), had a total completion cost of $498,975. The project had a post-construction IRR of nine percent (see Exh. KEDNE/PJM-10, at 1). The SMA and closing report associated with this project, however, were not included in the 550 SMAs and closing reports produced by the Company

(Exh. AG 1-19).[33] This project was placed in service in 2001 and is, therefore, used and useful. However, because the Company has not demonstrated that the investment was prudently incurred, we will exclude the project cost of $498,975 from rate base.

c. Projects With Post-Construction IRRs Greater Than Weighted Average Cost of Capital But Less Than Company Thresholds

Of the 83 revenue-producing projects completed by Boston Gas between 1996 and 2002, the Attorney General has identified ten projects with post-construction IRRs that were greater than 9.38 percent, but less than the Company's 11.75 percent IRR threshold for residential projects.[34] The Attorney General has also identified eight projects with IRRs greater than the 11.75 percent residential threshold, but less than the 12.75 percent IRR threshold applied for C&I projects.[35] Of these 18 projects, the Department has examined the SMAs and closing reports for eight projects with a Company IRR threshold of between 9.38

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[33] Boston Gas was asked to provide the "capital authorization and closing reports for all projects begun or finished during the last seven years of $50,000 or more in magnitude" (Exh. AG 1-19). The Company instead provided documentation for projects in excess of $100,000, stating that the requested $50,000 threshold is "relatively low" and would involve the production of approximately 800 more work orders in addition to the 550 work orders already produced (Exh. AG 1-19).

[34] The work order numbers for these ten projects are: 620U, 28507, 31443, 57965, 78752, 68904, 106700, 199770, 200021, and 93010 (Exh. KEDNE/PJM-10, at 1-2). The total completion costs of these ten projects is $3,441,630 (id.).

[35] The work order numbers for these eight projects are: 952Q, 42648, 75948, 65725, 101932, 168829, 169744, and 169907 ((Exh. KEDNE/PJM-10, at 1-2). The total completion cost of these eight projects is $4,769,292 (id.).

and 11.75 percent (residential threshold), and six projects with a Company IRR threshold of between 11.75 percent and 12.75 percent (C&I threshold).[36]

Regarding the eight work orders that have post-construction IRRs that are above 9.38 percent, but are lower than the Company's residential threshold of 11.75 percent, the SMAs for two projects (Concord Avenue, Lexington (work order number 199770) and Wood Street, Lexington (work order number 200021)) fail to indicate that any pre-construction IRRs were calculated or that cost-benefit analyses were performed (Exh. AG 1-19, Att. AG 1-19 (a)). In addition, the SMAs for these two projects do not contain any authorizing signatures (id.).

Further, the completion cost of the Concord Avenue project was $171,573, compared to an estimated investment cost of $98,668, resulting in a cost overrun of $72,906, or 74 percent (Exh. AG 1-19, Att. AG 1-19 (a)). The Company did not provide evidence of any

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[36] The remaining four projects were constructed in: (1) Groton (work order number 28507) at a completion cost of $105,767; (2) Webster (work order number 31443) at a completion cost of $372,754; (3) Wayland (work order number 952Q) at a completion cost of $241,895; and (4) Peabody (work order number 42648) at a completion cost of $129,985 (Exh. KEDNE/PJM-10). While the SMAs and closing reports associated with these projects could not be located among the 550 SMAs and closing reports that the Company included in exhibit AG 1-19, these projects went into service between 1997 and 2000 and are, therefore, used and useful. Moreover, each of the projects also had post-construction IRRs ranging between ten and twelve percent (Exh. KEDNE/PJM-10, at 1). While these projects did not meet Boston Gas' internal IRR thresholds, they did exceed the Company's WACC (Tr. 7, at 814-815). The Department will, in this case, include the total cost of these projects in rate base. However, as we noted above, a gas utility company has the burden of proof to demonstrate that its investment is prudent and that its decisions to serve new loads would not raise the cost of service to existing ratepayers. D.P.U. 88-67 (Phase I) at 282-284.

specific cost containment efforts or justifications for this overrun. Accordingly, consistent with the findings above regarding cost overruns, the Department denies the cost overrun associated with this project, and will reduce the Company's rate base by the associated cost overrun of $72,906.

The completion cost of the Wood Street project was $378,554, compared to an estimated investment cost of $384,203, resulted in a cost underrun of $5,649, or one percent (Exh. AG 1-19, Att. AG 1-19 (a)). Despite the lack of a pre-construction IRR analysis and lack of authorizing signatures, this project was placed in service in 2002 and had a post-construction IRR of eleven percent (Exh. KEDNE/PJM-10, at 1). Therefore, the Department will include the cost of this project in the Company's rate base.

We now turn to the remaining six projects that have post-construction IRRs that are above 9.38 percent, but lower than the Company's residential threshold of 11.75 percent. The SMAs for (1) Sanderson Lane, Weston (work order number 620U), (2) Heath Street, Brookline (work order number 57965), (3) Maverick Street, East Boston (work order number 78752), (4) Kettle Hole Drive, Lincoln (work order number 68904), (5) Main Street, Middleton (work order number 106700), and (6) Wormwood Street, South Boston (work order numbers 93010 and 121927) show that the Company performed gross margin analyses for each project, calculated a payback period of 16.1 years for the Sanderson Lane project, and calculated a pre-construction IRR of 16.4 percent for the Kettle Hole Drive project. These analyses are adequate economic justifications for project initiation. Therefore, the Department will allow the total costs of $1,151,037 associated with the Sanderson Lane and Main Street

projects.

However, four of the six projects listed above show significant cost overruns. The SMA and closing report associated with Heath Street show a total estimated investment of $138,405 and a completion cost of $228,949, resulting in a cost overrun of $90,545, or 65 percent (Exh. AG 1-19, Att. AG 1-19 (a)). The SMA and closing report associated with the Maverick Street project show a total estimated investment of $115,253 and a completion cost of $254,185, resulting in a cost overrun of $138,932, or 121 percent (id.). The SMA and closing report associated with the Kettle Hole Drive project show a total estimated investment of $99,644 and a completion cost of $210,315 resulting in a cost overrun of $110,671, or 111 percent (id.).[37] Finally, the SMA and closing report associated with the Wormwood Street project show a total estimated investment of $167,847 and a total completion cost of $568,718, resulting in a cost overrun of $400,871, or 238 percent (id.). Although these four projects are presently used and useful, Boston Gas failed to provide evidence regarding any cost containment efforts or justifications explaining the large cost overruns. Therefore, the Department finds that the Company has failed to show that the costs associated with these projects were prudent. Accordingly, consistent with the findings above regarding cost overruns, the Department will exclude from rate base $741,019, representing the cost overruns associated with these projects. The Department will permit the Company to include in rate base both the original cost estimates associated with these four projects of $521,149.

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[37] The SMAs for work order numbers 57965, 78752, and 68904 show no signatures approving those three projects (Exh. AG 1-19, Att. AG 1-19 (a)).

We now turn to the six work orders that indicate post-construction IRRs that are greater than Boston Gas's 11.75 percent threshold for residential projects, but lower than the Company's 12.75 percent threshold for C&I projects. The SMAs associated with the following five projects show that the Company performed gross margin analyses: (1) Forest Avenue, Swampscott (work order number 75948); (2) Dixon Meadows, Weston (work order number 65725); (3) 25 Walk Hill Street, Jamaica Plain (work order number 101932); (4) Great Pine Estates, Whitman (work order number 168829); and (5) Southampton Street, Boston (work order number 169744) (Exh. AG-1-19, Att. AG 1-19 (a)). These analyses are adequate economic justifications for project initiation. These projects were placed into service between 2000 and 2002 and are, therefore, used and useful (Exh. KEDNE/PJM-10, at 1-2).

The SMA and closing report associated with the Forest Avenue project show a total estimated investment of $68,822 and a completion cost of $456,544, resulting in a cost overrun of $387,722, or 563 percent (Exh. AG 1-19, Att. AG 1-19 (a)). In addition, the SMA and closing report for the Walk Hill Street project show a total estimated investment of $91,044 and a completion cost of $217,116, resulting in a cost overrun of $126,072, or 138 percent (id.). The Company did not provide any evidence regarding specific cost containment efforts or justifications for these cost overruns. Accordingly, consistent with the findings above regarding cost overruns, the Department will exclude from rate base the amount of $387,722 and $126,072, representing the cost overruns for the Forest Avenue and Walk Hill Street projects.

Finally, the SMA associated with a second Walk Hill Street, Jamaica Plain, project (work order number 169907) indicates that no gross margin calculations, IRR, or cost benefit analysis was performed prior to project initiation (id.). In addition, the SMA shows no signature approving the initiation of the project (id.). However, the closing report indicates that the project was completed on December 31, 2002 at a total cost of $3,151,263, or 39 percent below projected costs (Exh. AG 1-19). Because the Walk Hill Street project is currently used and useful, resulted in a final cost significantly below the original estimate, and has a post-construction IRR of twelve percent, the Department will allow the cost of this project to remain in rate base.

Based on this analysis, the Department has excluded $3,744,533 in plant investment from Boston Gas' proposed rate base. In recognition of this reduction, a corresponding reduction to the Company's depreciation reserve is appropriate. D.P.U. 92-210, at 24. The Company applies an average-year convention in computing its annual depreciation expense (Tr. 24, at 3322). This produces an accumulated depreciation balance equal to one-half the annualized depreciation expense for the plant during its first year in service. The Company's depreciation rate for mains during this period was 2.49 percent, and the disallowed projects were placed into service during the years 2000 through 2002 (Exhs. KEDNE/PJM-2 [supp.] at 158; KEDNE/PJM-10). Therefore, the Department will determine the depreciation reserve adjustment associated with disallowed plant expenditures by (1) multiplying the disallowed portion of projects completed during 2000 by 2.5 times the 2.49 percent depreciation accrual rate, (2) multiplying the disallowed portion of projects completed during 2001 by 1.5 times the

2.49 percent depreciation accrual rate, and (3) multiplying the disallowed portion of projects completed during 2002 by 0.5 times the 2.49 percent depreciation accrual rate. Application of the method described above to the respective disallowed plant investment results in an accumulated depreciation reserve of $109,148. Accordingly, Boston Gas's depreciation reserve associated with these projects will be reduced by $109,148.

C. Non-Revenue Producing Plant Additions

1. Introduction

A non-revenue producing plant addition is primarily intended to meet a utility's continuing service obligation to its existing customers. Boston Gas provided the project number, location, description, and the amount of each non-revenue producing project in excess of $100,000, completed between 1996 and 2002 (Exhs. KEDNE/PJM-1, at 44-45; KEDNE/PJM-8). In 2002, Boston Gas completed a project located in West Roxbury for the amount of $575,541 (Exh. KEDNE/PJM-8, at 1). This project, approved on August 31, 2000, with a total cost estimate of $87,097, involved the installation of 800 feet of twelve-inch main relay for service to West Roxbury High School (Exhs. AG-12; AG-1-19(a); Tr. 7, at 809).

2. Positions of the Parties

a. Attorney General

The Attorney General recommends that the Department remove $575,541 from rate base, representing the total cost of the West Roxbury project (Attorney General Brief at 27-28). The Attorney General claims that the 2000 authorization report for this project's work order shows a projected cost of only $87,000, while the closing report rendered two and

one-half years later shows a project completion cost of $575,541 (id. at 28). The Attorney General asserts that the Company was unable to explain the reasons for the delay and the cost overrun for this project (id., citing Tr. 7, at 812-813). The Attorney General claims that the Company only speculates in its brief about the reason for the overrun, without citing any relevant evidence (Attorney General Reply Brief at 18, citing Boston Gas Brief at 26 ("the work order involves a much larger job than originally estimated and would have likely involved two adjacent projects that were more efficiently accomplished at the same time")).

The Attorney General disagrees with Boston Gas' contention that Department precedent only requires a company to perform cost containment analyses on an overall basis (id. at 18). The Attorney General argues that the Department requires a review of each project installed since a company's last rate case, and that the Department has disallowed projects lacking adequate support (id. at 18-19, citing D.P.U. 92-210, at 24). The Attorney General argues that Boston Gas' reliance on overall numbers does not achieve the Department's objective of cost containment, because the Company would be free to let large dollar projects run far over budget, so long as the total amount invested each year remains under the weighted cost of capital (Attorney General Reply Brief at 19). The Attorney General claims that an individual project evaluation is more disciplined, logical, efficient, and requires the consistent application of cost-containment standards and monitoring of investments to achieve greater cost savings (id.).

The Attorney General claims that, on two prior occasions, the Department has ordered Boston Gas to develop a cost-benefit analysis for all non-discretionary, non-revenue producing

projects in excess of $100,000 (Attorney General Brief at 27, citing D.P.U. 93-60, at 35-36; D.P.U. 96-50 (Phase I) at 17). The Attorney General adds that the Department has also required Boston Gas to show that it sought to contain the costs of a project in those situations where a cost-benefit analysis is not applicable (Attorney General Brief at 27, citing D.P.U. 96-50 (Phase I) at 17). The Attorney General argues that, despite these prior directives, Boston Gas did not calculate the IRR for non-revenue producing projects and did not perform any cost-benefit analysis for the West Roxbury project (id. at 27-28). The Attorney General asserts that Boston Gas failed to provide the level of detail necessary for the Department to evaluate whether the costs of the West Roxbury project were monitored and controlled (id. at 28, citing D.P.U. 93-60, at 35). Claiming that a cost overrun of this magnitude is significant, the Attorney General asserts that Boston Gas should have investigated the reasons for the overrun, and demonstrated its efforts to control this project's costs before seeking to include the expense in rate base (id. at 28). Because the Company failed to adequately document that it took reasonable steps to contain the cost overrun, the Attorney General argues that the Department should remove the total West Roxbury project cost of $576,000 from rate base (id. at 28; Attorney General Reply Brief at 19).

b. Boston Gas

Boston Gas asserts that the West Roxbury project meets the Department's standard for inclusion of non-revenue producing investments in rate base (Boston Gas Brief at 25). Boston Gas alleges that the West Roxbury project street main authorization shows that it installed over 1,650 feet of main as compared to the 800 feet of pipe included in the original estimate (Boston

Gas Reply Brief at 37-38, citing Exh. AG 1-19 (work order number 79111, at 1, 4)). Boston Gas argues that the increased cost was not the result of a cost overrun, but due instead to "multiple reasons," including the installation of an additional 850 feet of main (Boston Gas Reply Brief at 38, citing Tr. 7, at 811-812). Boston Gas asserts that the Attorney General errs by claiming that the Company failed to provide any documentation for the $500,000 additional cost (Boston Gas Reply Brief at 38). The Company argues that, with the exception of questions posed during the evidentiary hearings, the Attorney General never requested an explanation as to the reasons for the cost overrun (id. at 38, n.19, citing Tr. 7, at 811-812).

Boston Gas contends that it has provided a sufficient showing of its cost-containment measures (id. at 39, citing Exhs. KEDNE/PJM-1, at 49- 51; DTE 4-41; AG 21-22). Boston Gas argues that Department precedent does not require the Company to perform cost-containment analyses on a project-by-project basis, noting that a cost-benefit analysis is not appropriate nor applicable to a non-revenue producing capital addition (id. at 26). Instead, Boston Gas asserts that it has demonstrated its cost containment efforts for its overall construction activities (id. at 26, citing Exh. KEDNE/PJM-1, at 49-51). Boston Gas claims that, although it has the burden of responding to questions on the record regarding specific projects, the Department has never required the Company to provide cost-containment descriptions for each individual project undertaken between rate cases, adding that this level of documentation would be burdensome to the Company's day-to-day management activities (Boston Gas Brief at 26).

Boston Gas argues that the WACC approach cited by the Attorney General is applicable to revenue-producing projects and not to non-revenue producing projects, like the West Roxbury (Boston Gas Reply Brief at 38, citing D.P.U. 92-210, at 23-24). The Company adds that there is no case precedent supporting the proposition that cost-containment measures must be demonstrated for individual non-revenue producing projects (Boston Gas Reply Brief at 38, citing D.P.U. 96-50, (Phase I) at 19-20, 21-22, 24).

3. Analysis and Findings

The standard of review for non-revenue producing projects is the same as the standard for revenue-producing projects. Both categories of expenditures must be prudently incurred and the resulting plant must be used and useful to ratepayers. D.P.U. 85-270, at 20.

In the case of non-revenue producing projects, the Department has recognized a distinction between discretionary and non-discretionary projects. For example, many non-revenue producing projects, such as cast-iron main replacements, may be fairly characterized as non-discretionary because the company is obligated to replace the main in order to maintain the integrity of the distribution system and comply with safety standards. On the other hand, in the case of projects such as the replacement of a customer information system or construction of a water treatment plant, a company has a measure of discretion, in that the company can select from among a number of options the most cost-effective means of meeting the company's operational needs. See D.P.U. 95-118, at 43-45.

Whether the non-revenue producing project is considered discretionary or non-discretionary, prudent utility management and common business practice would dictate the

need for a project-appropriate cost analysis to determine the cost of the project prior to commencement. D.P.U. 93-60, at 27. The scope of the pre-construction analysis would be dependent upon the nature of the project at issue. For example, the replacement of a cast-iron street main installed in 1890 would in all likelihood not warrant a full-scale cost-benefit analysis, but would instead consist of a reliable engineering estimate of project costs and a prioritization of the project in light of the company's other capital projects under consideration. On the other hand, a major capital project would warrant a more thorough analysis of the company's options, the criteria upon which a decision would based, and support for the decision reached. D.P.U. 95-118, at 43-45; 93-60, at 27.

Once the project has commenced, a company is expected to apply management tools, such as variance reports and related cost control measures, in order to monitor project costs and allow management to take corrective action as appropriate in event of a cost overrun. D.P.U. 93-60, at 35. If the company can demonstrate that it has taken appropriate cost-containment measures in a non-revenue producing project, and adequately justifies the reasons for any cost overrun, the Department will consider the costs of the project eligible for inclusion in rate base. If, however, the company is unable to justify the reasons for a cost overrun, the Department will exclude the excess costs to the extent that they have been found to have been imprudently incurred. D.P.U. 95-118, at 49-55.

In the case of Boston Gas's non-discretionary and discretionary non-revenue producing projects, the Department has directed the Company to (1) perform a cost-benefit analysis or employ a similar management tool for projects in excess of $100,000, (2) budget all indirect

costs as part of its budget authorizations, and (3) support the project authorizations with sufficiently detailed cost-benefit analyses commensurate with the project's complexity and expense. D.P.U. 93-60, at 35-36; D.P.U. 96-50 (Phase I) at 17.

Boston Gas asserts that it need not perform cost-containment analyses on a project-by-project basis on its non-revenue producing projects, but only on an overall basis (Boston Gas Brief at 26; Boston Gas Reply Brief at 38). However, the Department has twice before addressed the issue of the costs of the Company's non-revenue producing projects, stating:

> In the case of projects for which cost-benefit analysis may not be applicable, such as street main replacements, the Department placed the Company on notice that it expected the Company to demonstrate that it sought to contain the overall cost of such projects.

D.P.U. 96-50 (Phase I) at 17, citing D.P.U. 93-60, at 35, n.13. The Department's directives in D.P.U. 95-50 (Phase I) at 17 referred to individual non-revenue producing projects, as opposed to an aggregate non-revenue producing projects that Boston Gas may embark upon. Acceptance of Boston Gas's interpretation of our directive to mean the aggregation of non-revenue producing projects would be untenable as it would provide utility companies with convenient avenues for masking cost overruns and management failures in one project through blending the project in with the overall result for all projects. Moreover, the aggregation of non-revenue projects would frustrate the ability of management in its ability to identify and control costs.

The Company lists the various cost containment measures that it has undertaken for capital projects, including bypass analysis, consolidated purchasing, warehouse consolidation,

data management systems, and revised contractor bidding processes (Exh. KEDNE/PJM-1, at 49-51). Despite these recent developments, Boston Gas' operations changes in this area are reviewable only in relation to the Company's overall construction program, and provide no means to determine the extent to which they relate to specific projects. Thus, we reaffirm our previous directive, as noted above, that all companies must fully monitor and control construction costs, whether discretionary or non-discretionary in nature, or risk disallowance of such expenditures. D.P.U. 93-60, at 35-36; D.P.U. 96-50 (Phase I) at 17.

The West Roxbury project main relay is currently being used for service to the West Roxbury High School and, therefore, we find that the main is used and useful. The project had an initial total cost estimate of $87,097. The street main authorization for the work order related to the West Roxbury project (work order number 79111, approved on June 27, 2000) specified the installation of an 800-foot steel main pipe with a twelve-inch diameter as a main relay (Exh. AG-12). Boston Gas performed a gross margin analysis prior to starting the project. The gross margin analysis showed an annual gross margin to the Company of $63,375 per year associated with the proposed investment (id.). Therefore, the Department finds that the Company was economically justified in starting the project.

The West Roxbury project was completed in 2002 for the amount of $575,541 (Exh. KEDNE/PJM-8, at 1). The project had a $488,444 cost overrun, which is 5.6 times its estimated cost. Boston Gas has failed to establish that it contained the costs of the West Roxbury project. The Company's argument that the increased cost of the West Roxbury project was not the result of a cost overrun, but rather were prudent in light of an increase in

the project's scope (i.e, the project involved the construction of an additional 850 feet of main, or that the project involved an adjacent project) is not supported by the record evidence. The SMA and the accompanying closing report for the project do not demonstrate that an additional 850 feet of main was installed, but instead reference an already existing 1,650 feet of six-inch service line (Exh. AG-12, at 2). Therefore, the Department finds that the Company has not demonstrated, in a reviewable manner, that the costs related to the overrun were reasonably and prudently incurred.

Because the project is used and useful and because Boston Gas performed a proper analysis to show that it was economically justified in starting the project, we will not disallow the entire cost of project. However, because the Company failed to demonstrate that it adequately contained the cost of the project, the amount of the cost overrun is disallowed. Accordingly, the Department will reduce the Company's proposed rate base by $488,444, representing the difference between the project completion cost of $575,541 and the project estimated cost of $87,097.

In recognition of this rate base reduction, a corresponding reduction to the Company's depreciation reserve is appropriate. D.P.U. 92-210, at 24. As noted above, the Company applies an average-year convention in computing its annual depreciation expense (Tr. 24, at 3322). Because the West Roxbury project was completed during the test year, the Company's test year-end depreciation reserve include one-half year of depreciation accruals associated with the West Roxbury project. A failure to recognize this depreciation accrual would thereby overstate the net rate base adjustment necessary for the West Roxbury Project.

Therefore, the Department finds it appropriate to recognize one-half year of accumulated depreciation for this project (see Exh. KEDNE/PJM-10). The Company's depreciation rate for mains during the test year was 2.49 percent (Exh. KEDNE/PJM-2 [supp.] at 158). Therefore, the Department will determine the depreciation reserve adjustment associated with the West Roxbury project by multiplying the disallowed portion of the West Roxbury project, $488,444, by one-half of the annual depreciation rate of 2.49 percent, or 1.245 percent. Application of this method produces an accumulated depreciation reserve of $6,081. Accordingly, Boston Gas's depreciation reserve associated with the West Roxbury project will be reduced by $6,081.

D. Customer Record Information System

1. Introduction

Following Keyspan's acquisition of Eastern Enterprises, Keyspan implemented a single customer information system for its distribution companies in New York and New England (Exh. KEDNE/PJM-1, at 46-47). To this end, Boston Gas invested $32,989,138 during the test year for the conversion of its customer service system ("CSS") to the CRIS (id.; DTE 7-10). The Company's information systems were fully converted to the CRIS on July 1, 2002 (Tr. 25, at 3455). Boston Gas proposes to include in rate base its allocated share of the CRIS totaling $21,831,251, with accumulated amortization of $1,101,064 (Exhs. KEDNE-PJM-2 [supp.] at 210; DTE 7-10; Tr. 25, at 3455-3456).

2. Positions of the Parties

a. Attorney General

The Attorney General argues that the Department should disallow the entire cost of the CRIS and remove it from the Company's rate base (Attorney General Brief at 29; Attorney General Reply Brief at 22-23). In support of his position, the Attorney General maintains that Boston Gas neither conducted a cost-benefit analysis nor provided any other meaningful analysis of the project, including documentation of the Company's cost containment efforts (Attorney General Brief at 30, citing Tr. 7, at 805-806; D.P.U. 96-50 (Phase One) at 17; Attorney General Reply Brief at 20-21). Therefore, the Attorney General contends that the Company has not shown its investment in the CRIS was prudent (Attorney General Brief at 30).

The Attorney General argues that the Company has not adequately quantified the customer benefits of the CRIS, but instead has only provided an assessment of technologies and a quantification of benefits of the cost of migrating Keyspan's New England companies to the CRIS versus the cost of purchasing a new system with the same functionality of the CRIS to replace the CSS (Attorney General Reply Brief at 21-22, citing Exh. AG 22-9). The Attorney General claims that this analysis is insufficient because the standard for recovery of project costs through inclusion in rate base requires more than a general discussion of decisions made by the Company (Attorney General Reply Brief at 22, citing D.P.U. 92-210, at 24). The Attorney General asserts that Boston Gas is the party who must demonstrate the prudence of its investments (Attorney General Reply Brief at 19, citing Boston Gas Brief at 27; D.P.U. 95-40,

at 7; D.P.U. 93-60, at 26; 376 Mass. 294, at 304; 352 Mass. 18, at 24).[38] The Attorney General argues that the Department cannot rely on the unsupported testimony of Company witnesses that a project was beneficial at the time the decision was made, but that the Company must provide reviewable documentation for investments it seeks to include in rate base (Attorney General Reply Brief at 22).[39] The Attorney General asserts that Boston Gas has provided less information to support its investment in the CRIS in this case than it provided in support of the original CSS investment in D.P.U. 93-60 (id.).

Second, the Attorney General argues that the Company did not comply with the Department's competitive bidding requirements for the procurement of outside services (Attorney General Brief at 30, citing D.T.E. 01-56, at 73; D.P.U. 96-50 (Phase I) at 79). The Attorney General claims that the Company did not issue a request for proposals ("RFP") and failed to select qualified vendors for the CRIS conversion project (Attorney General Brief

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[38] The Attorney General argues that the Company has the burden of demonstrating the prudence of each capital investment proposed for recovery in rate base (Attorney General Brief at 29, citing D.P.U. 92-210, at 24 (1992)). The Attorney General argues that in prior rate cases, the Department has directed the Company to (1) use cost-benefit analysis or a similar management tool to review all nondiscretionary projects in excess of $100,000, (2) budget all indirect costs as part of its budget authorizations, and (3) support the project authorizations with sufficiently detailed cost-benefit analyses commensurate with the project complexity and expense (id. at 29, citing D.P.U. 96-50 (Phase I) at 17; D.P.U. 93-60, at 35-36). The Attorney General adds that where a cost-benefit analysis was not applicable to a particular project, the Department requires a company to demonstrate that it sought to contain the overall costs of the project (id. at 29, citing D.P.U. 96-50 (Phase One) at 17; D.P.U. 93-60, at 35, n.13).

[39] The Attorney General asserts that the Company testimony regarding the benefits of the CRIS is subjective, qualitative and not independent (Attorney General Reply Brief at 21, citing Boston Gas Brief at 28; Exh. KEDNE/PJM-1, at 47).

at 30). Therefore, the Attorney General maintains that the Company has failed to demonstrate the reasonableness of the costs of its CRIS conversion efforts (id.).

Third, the Attorney General claims that the Company experienced several significant problems with the conversion and implementation of the new billing system (Attorney General Brief at 30-31). These problems include (1) errors that resulted in late payment charges not billed, (2) misleading reports of ECS data, (3) missing write-off recovery for three months of the test year, and (4) faulty weather normalization data (id., citing RR-AG-6; RR-DTE-22;Tr. 6, at 690-691, 701; Tr. 8, at 965-966). The Attorney General reasons that, in addition to the implementation problems Boston Gas has experienced with the CRIS, the system's use of real-time billing adjustments would eliminate the ability of the Department or customers to verify individual bills from the meter data and tariff provisions (Attorney General Brief at 31-32). Therefore, because of the Company's failure to comply with Department directives, its inability to establish that the CRIS was prudent, and concerns over the reliability of the CRIS data, the Attorney General urges the Department to deny the Company any recovery of its CRIS conversion costs (Attorney General Reply Brief at 22).

In addition, because of what he characterizes as problems with the implementation of the CRIS, as well as a lack of documentation by Boston Gas of the original scope of the CRIS conversion project, the Attorney General questions whether the Company's CRIS-related expenditures included work actually done to upgrade (or support future) upgrades for the benefit of Keyspan's New York utilities (id. at 21, n.15). Therefore, the Attorney General suggests that the Department require an independent audit of the CRIS (Attorney General Brief

at 31; Attorney General Reply Brief at 21). The Attorney General suggest that any audit be designed to determine the accuracy of bills generated since the time of conversion, the ability of the CRIS to accurately generate bills in compliance with Department Orders, and examine the scope of the CRIS project to determine whether costs allocated to Boston Gas were incurred for the benefit of other Keyspan companies (Attorney General Brief at 31; Attorney General Reply Brief at 21, n.15).

b. Boston Gas

The Company claims that it has met the Department's standard in relation to its CRIS investment (Boston Gas Brief at 28). According to Boston Gas, following Keyspan's acquisition of Eastern Enterprises, Keyspan's system integration efforts included the implementation of a single customer information system for the Keyspan distribution companies in New York and New England (Exh. KEDNE/PJM-1, at 46-47). In evaluating its customer information system needs, the Company claims that it was considering the replacement of its existing CSS (id. at 47). Boston Gas states that the CSS required replacement because the system was at the end of its useful life, and had a database structure that was obsolete and lacking in functionality (Boston Gas Brief at 28, citing Exhs. KEDNE/PJM-1, at 46-48; AG 6-87). Boston Gas maintains that, given the need to replace its CSS, the Company was left with two options, i.e., to either purchase and implement a new system as it did in 1992, or to migrate the customer-data records to the CRIS (Boston Gas Reply Brief at 42, citing Exhs. KEDNE/PJM-1, at 46-48; AG 6-87).

In deciding to convert to CSS, the Company maintains that the CRIS offered a more sophisticated database structure with greater flexibility and efficiency in retrieval and managing customer data (Boston Gas Brief at 28, citing Exhs. KEDNE/PJM-1, at 46-48; AG-6-87). Moreover, Boston Gas states that its analysis showed that the cost of developing a new system for Boston Gas would be substantially higher than the cost of converting the CSS system to the CRIS (Boston Gas Brief at 28, citing Exh. KEDNE/PJM-1, at 47-48; Exhs. AG 6-87; AG 22-9). According to Boston Gas, the conversion of its CSS records to Keyspan's CRIS would provide a higher level of functionality in serving customers without the need for purchase of a new system, and would cost significantly less than purchasing and implementing a new system with the same level of functionality (Boston Gas Reply Brief at 40, citing Exhs. KEDNE/PJM-1, at 46-48; AG 6-87; AG 22-9; Tr. 7, at 806-807, 838-839; Tr. 12 at 1553).

The Company noted that it faced a similar situation regarding customer information systems in D.P.U. 93-60, when its prior customer billing system required replacement (Boston Gas Reply Brief at 40, citing D.P.U. 93-60, at 15). Boston Gas notes that, despite the Attorney General's recommended disallowance of the CSS investment at that time, the Attorney General had not questioned the need for an improved customer information system (id. at 40-41, citing D.P.U. 93-60, at 15). Boston Gas argues that, just as the Department found in D.P.U. 93-60 that the Company had acted prudently in determining that the then-existing billing system was in need of replacement, the Company's determination that CSS was near the end of its useful life prior to the Keyspan/Eastern Enterprises acquisition should be accepted here (Boston Gas Reply Brief at 41-42, citing Exhs. KEDNE/JFB-1, at 47;

AG 6-87). The Company contends that because the Attorney General did not rebut the Company's testimony in this proceeding on the need to replace the CSS system, the evidence regarding the need to replace the CSS system and the increased functionality that would result from a replacement of the system is uncontroverted (Boston Gas Reply Brief at 41-42, citing Exhs. KEDNE/PJM-1, at 46-48; AG 6-87; AG 22-9; AG 22-1; Tr. 7, at 806-807; Tr. 12, at 1553). Therefore, the Company asserts that the Department should find that the Company acted prudently in determining that its billing system was in need of replacement (Boston Gas Reply Brief at 42, citing D.P.U. 93-60, at 26).

The Company disputes the Attorney General's claims that the Company did not provide any cost-benefit analysis or cost-estimation analysis supporting the decision to convert from the CSS to the CRIS (Boston Gas Brief at 28, n.18; Boston Gas Reply Brief at 42, citing Attorney General Reply Brief at 21). Boston Gas contends that, unlike the situation presented in D.P.U. 93-60, the Company did not have the option of maintaining the existing CSS system (Boston Gas Reply Brief at 43, citing Exh. KEDNE/PJM-1, at 47-51).[40] The Company emphasizes that it has laid out in detail, as part of its initial filing, the decision-making process and the rationale that resulted in the conversion of the CSS customer-data records to the CRIS

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[40] The Company emphasizes that in D.P.U. 93-60, the CSS project involved the purchase, design, installation of new database management and a new customer information software package. The Company argues that this is not analogous to the circumstances in the instant docket which involve the conversion to an existing system (Boston Gas Brief at 43, citing D.P.U. 93-60, at 14-17). In addition, the Company argues that in D.P.U. 93-60, at 27, the Department noted the "desirability," but did not require the use of a cost-benefit analysis to evaluate the "comparative costs of maintaining an existing system versus any alternatives" (id. at 43).

(Boston Gas Reply Brief at 40, citing Exh. KEDNE/PJM-1, at 46-48). The Company adds that it purposely included a detailed discussion about its conversion to the CRIS as part of its initial filing in response to the Department's concerns in D.P.U. 93-60, at 25 over the limited narrative testimony provided on its CSS as part of the initial filing in that docket (Boston Gas Reply Brief at 40).

The Company asserts that whether it migrated the customer-data records to the CRIS or purchased and implemented a new system, the Company would have still incurred the costs of converting 1,395,877 current and historical customer accounts and 290,297,069 customer records to a replacement hardware and software platform (Boston Gas Reply Brief at 42, citing Exh. AG 6-87). The Company argues that, because the $48 million overall cost of the CRIS hardware and software platform had already been absorbed by Brooklyn Union Gas ("BUG"), the only cost incurred by Boston Gas to migrate its customers into the CRIS were costs associated with converting its New England customer records to the CRIS, which would have been required regardless of whatever customer information system was selected (Boston Gas Reply Brief at 42-43). Therefore, Boston Gas maintains that the incremental hardware and software costs associated with the development and implementation of a new system were avoided with the conversion to the CRIS (Boston Gas Brief at 43). The Company claims that this analysis constituted an appropriate and acceptable "management tool" to assess the costs of the system, and noted further that cost-benefit analyses are not generally applicable to non-discretionary, non-revenue producing projects (Boston Gas Brief at 29-30, citing D.P.U. 96-50 (Phase I) at 17).

Regarding the Attorney General's assertion that the Company "must provide reviewable documentation for investments it seeks to include in rate base," the Company argues that it made a comprehensive presentation of job order and closing report for the CRIS detailing each individual cost item involved in the CRIS project investment (Boston Gas Reply Brief at 44, citing Attorney General Reply Brief at 22; Exh. AG 6-86; Tr. 25, at 3404-3422; RR-DTE-107; RR-DTE-108). The Company argues that these reports represent the most detailed financial analysis available through Keyspan financial systems short of resorting to accounts payable or payroll data, and that this presentation enables the Department to review the Company's CRIS costs by line item (Boston Gas Reply Brief at 44).

Boston Gas asserts, contrary to the Attorney General's claims, that it has provided evidence of its cost containment efforts during the CRIS conversion, noting that the majority of the costs associated with the data conversion involve straight time labor by Keyspan employees and technical consultants retained to assist Keyspan employees (Boston Gas Brief at 29; Boston Gas Reply Brief at 44, citing Exh. AG 6-86). The Company contends that it solicited bids from approximately 50 vendors, allowing it to screen candidates to act as technical consultants to in-house personnel in completing the conversion, and that it hired these consultants on a 30-day trial basis to ensure that they met the Company's needs (Boston Gas Brief at 29; Boston Gas Reply Brief at 44, citing Exhs. AG 22-29; AG 6-87; AG 6-87 [supp.] (Att.)). Boston Gas notes that the only aspect of the project that was not competitively bid was some limited technical assistance required for data-conversion tasks that the Company deemed to require a unique expertise (Boston Gas Brief at 30, citing Exh. AG 6-87). The Company adds that, with

the exception of $63,407 in bonus payments paid to Keyspan employees who worked on the CRIS conversion, the Attorney General has raised no issue with the actual costs incurred for the project (Boston Gas Brief at 30, citing RR-AG-100).[41]

The Company asserts that there is no evidence to support the Attorney General's claim that the Company experienced "significant problems" with conversion and implementation of the new billing system (Boston Gas Brief at 31). The Company argues that it experienced normal and routine implementation issues relating to the generation of reports between the New York and New England jurisdictions, and that these issues have now been corrected or resolved (id., citing RR-AG-36). The Company notes that both the CSS and the CRIS are complicated systems designed to handle data in specific ways and to generate specific reports that have evolved over time (Boston Gas Brief at 31). Moreover, the Company claims that the Department's standard for prudence review is based on a review of the information known to management at the time a decision is made, and that a determination as to the prudency of a utility's actions is not properly made on the basis of hindsight judgments (id.). The Company argues that the fact that there were conversion issues, significant or insubstantial, is irrelevant, unless it can be shown that they are a result of facts that were known or should have been known to management at the outset of the project (id. at 31-32).

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[41] During the test year, the Company paid a total of $90,494 in special cash awards to employees as part of its "Above and Beyond" incentive program for exemplary performance (RR-AG-100). These cash awards will be addressed in Section IV.H, below.

3. Analysis and Findings

The CRIS is a non-discretionary or non-revenue producing plant investment and must be evaluated under that standard, namely that the resulting investment must be used and useful in providing service to ratepayers and the expenditures must have been prudently incurred. D.P.U. 85-270, at 20. Boston Gas is currently using the CRIS for a range of necessary operational and informational tasks including customer billing, data storage and retrieval, and weather normalization of test year revenues (Exh. KEDNE/PJM-1, at 47-48). The CRIS went into operation for Boston Gas in July 2002, before the end of the test year (Tr. 25, at 3455). Accordingly, the Department finds that the CRIS is used and useful.

In determining whether the Company's investment in the CRIS is prudent, the Department must first examine whether the Company's decision to adopt the CRIS itself was reasonable. This determination involves examination of the alternatives Boston Gas had to the CRIS, including the retention of the existing CSS to perform what are acknowledged to be necessary tasks (i.e., customer billing, data storage and retrieval, etc.). A major factor in this analysis involves the extent to which the Company used a cost-benefit analysis or similar management tool to assist in its decision-making process. Finally, we must evaluate each phase of the CSS conversion, looking at the progress on the CRIS conversion, associated costs, and the cost-control techniques that the Company used.

When deciding whether to adopt Keyspan's CRIS, the Company determined that New England customers would best be served by the system-wide integration of the CRIS after considering the following factors: (1) the cost of modifying the existing CRIS to provide a

platform for the integration of the CSS used by Boston Gas for its own customers, as well as those of Colonial Gas Company ("Colonial"), Essex Gas ("Essex"), and EnergyNorth; and (2) the cost of converting the large volume of customer data records resident in the CSS to the CRIS (Exh. AG-6-87). The Company determined that the existing CSS had an obsolete database structure and had already been modified a number of times to handle gas unbundling and the integration of Colonial, Essex, and EnergyNorth (Exhs. KEDNE-PJM-1, at 47; AG 6-87; AG 22-9). Additionally, Keyspan's CRIS and Boston Gas' CSS systems were not compatible (Exh. AG 22-9). Given the Keyspan/Eastern Enterprises acquisition, and potential for economies of scale, the Department finds that there were reasonable business and economic rationales to decide upon the use of a common information system platform for the Keyspan companies.

Boston Gas' analysis, however, was limited to a comparison of the cost of migrating to the CRIS and the cost of obtaining a separate system that could provide the same functions as the CRIS (Exh. AG 22-9). The Company acknowledged it has no documentation regarding studies or information that isolate customer benefits associated with the implementation of the CRIS (id.). Customer benefits must be proved; and systematic, contemporaneous documentation of well-analyzed investment decision-making is the best evidence to sustain such a proof. The Department has previously cautioned utility companies that, as they bear the burden of demonstrating the propriety of additions to rate base, failure to provide clear and cohesive reviewable evidence on rate base additions increases the risk to the utility that the Department will disallow these expenditures. D.P.U. 95-40, at 7; D.P.U. 93-60, at 26; see

also 376 Mass. 294, at 304; 352 Mass. 18, at 24. A more rigorous application of cost-benefit analysis techniques in the decision-making process associated with the CRIS project, including systematic and contemporaneous documentation of such process, may not have produced a different conclusion, but would have been the best evidence of the Company's investment decision-making required to demonstrate the propriety of the CRIS' inclusion in rate base. Section III.C, above.

Having decided to embark on the CRIS conversion project, the Company required specialized expertise in order to proceed (Exh. AG-6-87). The conversion process consisted of two components: (1) system code modifications needed to support the business requirements of Keyspan's New England operations; and (2) data conversion that involved converting 1,395,877 current and historical customer accounts and 290,297,069 customer records from the CSS to the CRIS (id.). The Company has demonstrated that system code modification could best be accomplished using internal technical personnel, supplemented by additional outside contractors (id.). Moreover, the Company further demonstrated that data conversion required the use of external resources for program development, technical design, project management and administration (id.). Accordingly, the Department finds that the Company's assessment of its conversion requirements and resources to meet those requirements were adequate.

We have stated that competitive bidding is one important means for companies to control costs. As to whether the Company engaged in an adequate competitive bidding process, the Company solicited bids from approximately 50 vendors for the program

development on both the system code modification and data conversion phases (Exhs. AG 6-87; AG-6-87 [supp.]).[42] For the data conversion phase of the CRIS conversion, the Company interviewed initially only two potential vendors and retained one on the basis of the selected vendor's technical expertise (id.). However, a few months later, the Company determined that the unique features of the CRIS and the complexity of the project required a higher level of technical expertise than available from this vendor (id.).[43] Therefore, the Company terminated the vendor and engaged another vendor without the benefit of interviewing independent bidders or solicitations (id.).[44]

In assessing the Company's actions with respect to its selection of the initial data conversion vendor, the Department recognizes the complexities associated with the data conversion phase of the CRIS conversion project. However, the fact that only two vendors were initially interviewed for the data conversion project, with the initial vendor replaced by a second one not initially considered, raises the question of whether Boston Gas' bid solicitation process was adequate. The 30-day trial basis hire of most vendors may allow the Company to assess their performance in the decision to retain the vendors at the end of the trial period. However, the Department presumes that unsatisfactory performance would be a basis for

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[42] The two vendors interviewed by the Company for the data conversion process were not included among the 50 vendors initially solicited (Exhs. AG 6-87; AG 6-87 [supp.]). In addition, the vendor that the Company engaged after terminating the initially-hired vendor is not included among the list of vendors (id.).

[43] Boston Gas paid the terminated vendor $249,060 for its work on the project (Exh. AG 6-86(b)).

[44] Additional vendors were engaged to support the data conversion efforts (id.).

termination under any vendor contract, regardless of the term of the agreement. Had Boston Gas conducted a more comprehensive vendor selection process, the Company could have identified the limitations of the first vendor before the final selection was made, and thereby avoided the effort and cost associated with replacing the vendor. The Department finds that the Company's actions with respect to its selection of the first vendor were imprudent. D.P.U. 95-118, at 45-46; D.P.U. 93-60, at 27-29. Accordingly, the Department will exclude $249,060 representing the payments made to the first vendor from the Company's rate base. In the future, we expect companies to undertake a more comprehensive solicitation process when selecting vendors for all major capital outlays. Section IV.J.3.b, below (competitive bidding for rate case outside services).

Boston Gas encountered a number of technical problems as a result of the CRIS conversion. For example, the Company booked an incorrect level of bad debt writeoffs during the test year (Exh. AG 23-42; Tr. 8, at 964-966). The Company's systems also failed to calculate correct late payment charges (Exhs. KEDNE/AEL-1, at 12; DTE 1-30; Tr. 6, at 688-691). Finally, the Company's systems failed to accurately record ECS and energy efficiency revenues, which as a result required manual adjustments to the system (Exhs. DTE 4-58; AG 8-44; Tr. 6, at 701-703). These problems are related to coding difficulties encountered in the conversion process rather than problems with actual customer data. The Department recognizes that implementation problems associated with new technologies, such as customer information systems, do occur and would even be anticipated by the installer of that technology. The Department finds that, overall, the Company's actions with respect to the

system code modification and data conversion phases of the CRIS conversion project were prudent.

The Attorney General has urged the Department to direct Boston Gas to competitively solicit a qualified independent auditor to audit the CRIS as it relates to the Company, on the grounds that problems may still exist with the CRIS and affect future billings to Boston Gas ratepayers. The Attorney General's arguments on brief notwithstanding, there is no basis to currently conclude that the implementation problems associated with CRIS remain unresolved, or that the CRIS is incapable of generating bills and other customer information that would result from the Department's Order in this proceeding.[45] Therefore, the Department declines to adopt the Attorney General's proposal to audit the CRIS at this time.

As indicated above, the Department has found that the Company's actions with respect to the CRIS conversion project were lacking in key areas in both the initial stages of the project where the decision to implement the CRIS was made and in the selection process for outside vendors. The Department has evaluated the Company's prudence in these areas and made a disallowance where appropriate. The Department has also found that the Company's actions with respect to the system code modifications and data conversions were prudent, despite the problems that appeared in the system code modification phase. Taken as a whole, the Department finds that the Company's overall management of the CRIS conversion project

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[45] One concern raised by the Attorney General is the CRIS' ability to undertake tasks related to the Company's proposed weather stabilization mechanism (Attorney General Brief at 31). However, the Department has rejected the Company's proposal to implement a weather stabilization clause and, therefore, this concern is now moot. Section VI.G.3, below.

reached a an acceptable level of prudence. Therefore, the Department will not further reduce the Company's rate base associated with the CRIS.

Of the total $249,060 representing the disallowed portion of the CRIS, 7.6 percent, or $18,929, would be allocated to Essex (Exhs. KEDNE/PJM-2 [rev. 2] at 39; KEDNE/PJM-2 [supp.] at 168). Accordingly, the Department will reduce Boston Gas' proposed investment associated with the CRIS by a net total of $230,131.

In recognition of the Department's decision to exclude $230,131 in CRIS-related expenses from Boston Gas' rate base, a corresponding reduction to the Company's amortization reserve is appropriate. Boston Gas Company, D.P.U. 93-60-A at 7-8 (1993). As noted above, the Company applies an average-year convention in computing its annual depreciation expense (Tr. 24, at 3322). The Department considers the average-year approach to produce a reasonable level of the CRIS amortization that occurred during the test year. D.P.U. 93-60-A at 7-8. In order to determine the accumulated amortization associated with the CRIS through the end of the test year, the Department will apply one-half of the annual amortization, based on the ten-year amortization period used by the Company during the test year. Application of this factor to the $230,131 in disallowed CRIS investment produces an accumulated amortization associated with the disallowed portion of the CRIS of $11,507. Accordingly, Boston Gas's amortization reserve associated with the CRIS will be reduced by $11,507.

In D.P.U. 93-60, at 24-36, the Department excluded from Boston Gas' CSS investment in rate base a total of $1,072,210 in CSS-related investment, on the grounds that the

Company's actions with respect to the early stages of that project were imprudent. The decision-making processes associated with the CSS conversion project that were identified by the Department in D.P.U. 93-60, at 25-36, have their echoes today in the Company's management of its CRIS conversion project. If Boston Gas embarks on another major capital project in the future that relies on the same incomplete decision-making processes as were used in the CSS conversion project, the Company would have little basis for complaint if the Department were to reject all or a portion of the costs associated with that future project.

E. Computer Software Costs to Colonial

1. Introduction

Boston Gas proposes to increase its test year-end rate base by $937,026, representing software costs that were allocated to Colonial under the Securities and Exchange Commission ("SEC") cost allocation formula, but do not represent incremental cost to Boston Gas (Exhs. KEDNE/PJM-2 [rev.], at 39; KEDNE/PJM-2 [supp.] at 210). In support of this adjustment, the Company relied on the incremental cost analysis approved in Eastern-Colonial Acquisition, D.T.E. 98-128 (1999), which provides that only costs that are incremental to Boston Gas must be charged to Colonial (Exh. DTE 7-12, citing Exh. AG-11-1). No party commented on the Company's proposed adjustment.

2. Analysis and Findings

In D.P.U. 98-128, at 88-89, the Department directed Boston Gas to assign Colonial any incremental costs incurred by either the Company or Essex for providing services to Colonial, in order to protect Boston Gas' and Essex's customers from subsidizing Colonial's customers

and still allow merger-related savings to be allocated to Eastern Enterprise's shareholders. Consistent with this treatment, the Department has found in Section IV.S.3, below, that the Company has appropriately determined its incremental costs associated with the acquisition of Colonial. Additionally, the Department has reviewed Boston Gas' proposed allocation of software costs from Colonial, and finds that the Company has properly accounted for the non-incremental software costs (Exh. KEDNE/PJM-2 [supp.] at 210). Accordingly, we accept Boston Gas' proposed adjustment, increasing the Company's test year rate base by $937,026.

F. Leasehold Improvements

1. Introduction

As of the end of the test year, the Company's plant investment included $136,291 in leasehold improvements at its Beacon Street offices (Exh. KEDNE/PJM-1, at 39). Although the Company has vacated its Beacon Street offices and relocated the personnel formerly at that location to its new offices in Waltham, the lease remains in effect, and Boston Gas continues to pay rent on the facility (Tr. 2, at 166-167). Because Boston Gas removed its expenses associated with Beacon Street from test year cost of service, the Company has proposed to remove the Beacon Street leasehold improvements from rate base (Exh. KEDNE/PJM-1, at 39). None of the parties commented on the issue of leasehold improvements.

2. Analysis and Findings

Boston Gas continues to pay rent for the Beacon Street property (Tr. 2, at 167). Therefore, the leasehold improvements at that location have not yet been retired, and presumably remain available for Company use. However, leasehold improvements in vacant

office space provides no useful service to Boston Gas' ratepayers. Therefore, the leasehold improvements fail to meet the Department's used and useful standard for inclusion in rate base. D.T.E. 01-56, at 42-43; D.P.U. 93-60, at 41-44. Accordingly, the Department accepts the Company's proposed reduction to rate base of $136,291.

G. Cash Working Capital Allowance

1. Introduction

In their day-to-day operations, utilities require funds to pay for expenses incurred in the course of business, including operating and maintenance ("O&M") expenses. These funds are either generated internally by a company or through short-term borrowing. Department policy permits a company to be reimbursed for costs associated with the use of its funds for the interest expense incurred on borrowing. D.P.U. 96-50 (Phase I) at 26, citing Western Massachusetts Electric Company, D.P.U. 87-260, at 22-23 (1988). This reimbursement is accomplished by adding a working capital component to the rate base computation.

A time lag occurs between a company's payment of its O&M expenses and customers' payments for services rendered. The time lag involves two components: (1) the number of days between the delivery of gas service by the Company and the receipt of payment from customers ("revenue lag"); and (2) the number of days taken by the company to pay its O&M expenses ("expense lag"). Commonwealth Electric Company, D.P.U. 89-114/90-331/91-80 Phase One at 10 (1991). The difference is the net lag (or lead, if negative). Id. The net lag is then applied to annual O&M expenses to determine the average amount of working capital the

company must have on hand to cover the lag in recovery of revenues for services rendered. Id.

Non-fuel working capital requirements have been determined through either the use of a lead-lag study or a 45-day O&M expense convention. Because lead-lag studies are costly and complex to undertake, and because the costs associated with a lead-lag study are often out of proportion to the contribution of cash working capital to a company's rate base, the 45-day convention was developed in the early part of the last century as a simplified formula to value the amount of cash working capital to be included in rate base. D.P.U. 88-67 (Phase I) at 33. However, the Department has expressed concern that the 45-day convention no longer provides a reliable measure of a utility's working capital requirements. Fitchburg Gas and Electric Light Company, D.T.E. 98-51, at 15 (1998); D.P.U. 96-50 (Phase I) at 27. Therefore, the Department requires each gas and electric distribution company to either (1) conduct a lead-lag study where cost-effective, or (2) propose a reasonable alternative to a lead-lag study to develop a different interval.[46] D.T.E. 02-24/25, at 57.

Boston Gas engaged the services of an outside consultant to perform a lead-lag study (Exh. KEDNE/PJM-1, at 40). The Company developed two separate lead-lag factors, one based on expenses incurred directly by Boston Gas, and the other based on expenses billed to the Company by Keyspan Services (id.). The Company determined that lag between revenues

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[46] In this context, "cost-effective" means that the normalized cost of the study (i.e., the cost of the study divided by the normalization period used in the utility's rate case) is less than the reduction in revenue requirements that would occur using the results of the lead-lag study in lieu of the 45-day convention. D.T.E. 02-24/25, at 57, n.34 (2002).

and expenses for direct expenses was 43.46 days, using a revenue lag of 65.78[47] days and an expense lag of 22.32 days (Exhs. KEDNE/PJM-7, at 1; DTE 2-52; RR-AG-27; Tr. 6, at 690-691, 701; Tr. 8, at 965-966). Because the Company is allowed 30 days to pay Keyspan Services, Boston Gas reduced the net lag of 43.46 days associated with expenses billed by Keyspan Services to 13.46 days (Exhs. KEDNE/PJM-1, at 40; DTE 4-2; Tr. 1, at 15-16). As a result, the Company concluded that the appropriate working capital allowance based on test year O&M expenses would be $8,165,978 for direct Company expenses, and $3,154,101 for indirect expenditures.[48] Applying the corresponding lag factors to the Company's proposed adjustments to test year O&M expense, yields additional working capital requirements of $4,918,064 for direct expenses and $438,209 for indirect expenses (Exh. KEDNE/PJM-2 [rev. 2] at 41). Therefore, Boston Gas concluded that its total working capital requirement was $16,676,353 (Exh. KEDNE/PJM-2 [rev. 2] at 41). This working capital allowance corresponds to a composite net working capital factor of 28.7 days (Exh. DTE 3-14; Tr. 24, at 3362-3363). No other party addressed this issue.

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[47] Initially, Boston Gas reported that the revenue lag was 65.05 days (Exh. KEDNE/PJM-7, at 1). The Company revised the firm customer collection lag component of the revenue lag calculation from 46.72 days to 47.46 days (Exh. DTE 2-52; Tr. 1, at 15-16). This revision increases the firm customer revenue lag to 65.78 days, which when used in the computation, produces a net lag of 43.46 days (Exh. KEDNE/PJM-7, at 1-2; RR-AG-27).

[48] Using these factors, a composite working capital allowance of 26.81 days can be derived (Exh. KEDNE/PJM-2 [rev. 2] at 41).

2. Analysis and Findings

If properly designed, lead-lag studies are an appropriate method to determine cash working capital. However, lead-lag studies are complex and costly to undertake. In recognition of this fact, the Department has directed that companies propose alternatives to lead-lag studies if such studies are not cost-effective. D.T.E. 02-24/25, at 57. In the instant case, Boston Gas has proposed a composite 28.7-day cash working capital factor developed at a total cost of $36,769 (Exh. AG 5-6 [supp.] (August 1, 2003); Tr. 24, at 3362-3363). When we compare the normalized cost of the lead-lag study to the effect the lower resulting cash working capital factor has on revenue requirements, we conclude that the Company's decision to perform a lead-lag study was a cost-effective means to determine its working capital needs.

Turning to the merits of the Company's lead-lag study, one component of the revenue lag is the time between the date a customer's meter is read and the date a bill is rendered to that customer ("billing lag") (Exh. KEDNE/PJM-7, at 2). During July 2002, the Company implemented the CRIS, which allows for faster processing of customer bills (Tr. 25, at 3388). Boston Gas stated that as a result of the implementation of the CRIS, the billing lag has decreased from two to five days to between one and three days (Tr. 25, at 3388-3389). The Company anticipates that this trend towards shorter billing lags will continue (Tr. 25, at 3388-3389). The Department finds that the implementation of the CRIS during the test year benefits ratepayers in terms of reduced billing lags that would be incorporated into the Company's working capital needs. D.P.U. 96-50 (Phase I) at 26-28; Commonwealth Electric Company, D.P.U. 89-81/90-331/91-80 Phase One at 23 (1991).

Based on our review of the billing lags from July through December 2002, the average billing lag for meters read on cycles one through 20 during this period was 1.42 days (Exh. DTE 2-51). This decrease in billing lag represents a known and measurable change to the Company's overall test year billing lag. D.P.U. 89-114/90-331/91-80 Phase One at 22-23. Therefore, the Department finds that an appropriate billing lag factor for firm ratepayers is 1.42 days. Substitution of this factor for the Company's proposed billing lag of 2.12 days, as well as the Company's revised firm ratepayer collection lag of 47.46 days, produces a revenue lag of 65.09 days (Exh. KEDNE/PJM-7). This revision changes the net lag to 42.77 days (Exh. KEDNE/PJM-7, at 3). Accordingly, the Department will use a firm ratepayer net lag factor of 42.77 days in determining Boston Gas' working capital requirement.

In addition to calculating separate cash working capital allowance factors for direct Company and Keyspan Services O&M expenses, Boston Gas proposes to apply these factors separately to test year O&M expenses associated with direct Company and Keyspan Services expenses and to the proposed increase in direct Company and Keyspan Services O&M expenses (Exhs. KEDNE/PJM-1, at 40-41; KEDNE/PJM-2 [rev. 2] at 41). In reviewing other utilities with service company affiliates, the Department has not distinguished between test year direct company or service company charges and pro forma direct or service company charges when applying the results of a lead-lag study. D.P.U. 92-250, at 244; Massachusetts Electric Company, D.P.U. 92-78, at 219 (1992); D.P.U. 89-81/90-331/91-80 Phase One at 316 (1991); Western Massachusetts Electric Company, D.P.U. 89-255, at 154 (1990). While Boston Gas' approach may produce a more precise measure of the Company's cash working

capital requirements, it also requires an extensive amount of effort to separate pro forma O&M expense into direct Company and Keyspan Services charges in order to apply the separate cash working capital factors. The Department considers the level of precision that may be obtained through this identification process to be outweighed by the need for detailed calculations that would not be completely available until after the Department issues its Order and Boston Gas submits a compliance filing. Accordingly, the Department will not adjust the results of the lead-lag study for the mix of direct Company or Keyspan Services charges, but will apply a composite factor to the Company's overall level of pro forma O&M expense.

Based on the foregoing analysis, the Department finds that an appropriate lead-lag factor for direct Company expenses is 42.77 days. Turning to the lead-lag factor for charges rendered by Keyspan Services, we note that Keyspan Services allows its affiliates, including Boston Gas, 30 days to make payment (Exhs. DTE 4-2; DTE 4-3). The Department accepts the Company's proposed reduction in the lead-lag time for expenses billed by Keyspan Services. See D.P.U. 89-81/90-331/91-80 Phase One at 23-24 (1991). Based on the Department's decision to use a 46.77-day net lag for direct Company expenses, we will use a lead-lag factor of 12.77 days for charges from Keyspan Services. Application of these lead-lag factors to Boston Gas' respective test year O&M expense categories produces a composite cash working capital factor of 26.12 days (see Exh. KEDNE/PJM-7). Accordingly, the Department finds that 26.12 days represents an appropriate cash working capital factor for Boston Gas. The effect of this cash working capital allowance on the Company's revenue requirement is provided in Schedule 6 of this Order.

H. Unamortized Investment Tax Credits

1. Introduction

Prior to the Tax Reform Act of 1986, regulated utilities earned investment tax credits ("ITCs") equal to a percentage of qualifying investments (Tr. 20, at 2632).[49] In the case of ITCs earned prior to 1971, the Internal Revenue Code permitted the ratable amortization of credits as a reduction to income tax expense for cost of service purposes, with the unamortized balance of these credits allowed as a rate base deduction (Tr. 19, at 2621).

In the case of ITCs earned after 1970, the Internal Revenue Code requires companies to make a one-time election, for ratemaking purposes, of one of the following three options: (1) reduce rate base for the unamortized balance of post-1971 ITCs, and apply no ITC amortization to reduce income taxes ("Option 1"); (2) apply the ratable amortization of post-1970 ITCs as a reduction to income tax expense for cost of service purposes, with no rate base reduction for the unamortized balance of ITC ("Option 2"); or (3) if a company did not normalize its depreciation for ratemaking purposes, allow the state regulatory agency to make this determination (Exh. KEDNE AG 1-17 [supp.]; Tr. 19, at 2620-2622). The Internal Revenue Code specifically requires that only one of these options is available for ratemaking purposes and precludes the simultaneous application of more than one option (Tr. 20, at 2637). In addition, the Internal Revenue Code provides that if a company fails to affirmatively adopt Option 2, it will be considered an Option 1 company by default, with the unamortized balance

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[49] The applicable rate for computing investment tax credits varied between three percent, four percent, or ten percent, depending upon when the eligible property was placed in service.

of post-1970 ITCs deducted from rate base without any reduction to income taxes for ITC amortizations (Exh. KEDNE AG 1-17 [supp.]). The Company identified itself as an Option 1 company by default (Exh. KEDNE/PJM-14, at 7; Tr. 25, at 3512-3513).

During the test year, Boston Gas amortized $842,004 in ITCs for accounting purposes (Exh. AG 1-2B(8)(a) at 33). The Company did not include the $842,004 amortization in its calculation of income tax expense for cost of service purposes (Exh. KEDNE/PJM-2 [rev. 2], at 35). The Company, however, did reduce the rate base in this proceeding by the remaining unamortized ITCs at the end of the test year, which it represented to be $1,713,838 (Exh. KEDNE/PJM-2 [rev. 2] at 38, Sch. 4).

2. Position of the Parties

a. Attorney General

The Attorney General maintains that the $842,004 amortization of ITCs recorded for accounting purposes during the test year should be recognized in the calculation of income tax expense for cost of service purposes (Attorney General Brief at 39; Attorney General Reply Brief at 26). According to the Attorney General, the Department has always treated Boston Gas as an Option 2 company, i.e., one that applies a ratable amortization of post-1971 ITCs (id.). In support of his position, the Attorney General notes that the Department has included the amortization of ITCs in the calculation of income tax expense in Boston Gas' previous three rate proceedings, D.P.U. 96-50, D.P.U. 93-60, and D.P.U. 88-67 (Attorney General Reply Brief at 26, citing Tr. 25, at 3513-3516).

Maintaining that Boston Gas has offered no reason why the Department should change the treatment of post-1970 ITCs that the Company has used for at least fifteen years, the Attorney General concludes that the Company's calculation of income tax expense in this proceeding should include investment tax credit in the amount of $842,000 (Attorney General Brief at 40). According to the Attorney General, this adjustment would reduce the pro forma income tax expense by $842,000 and the Company's revenue requirement by $1,385,000 (Attorney General Brief at 40; Attorney General Reply Brief at 26).

b. Boston Gas

The Company argues that it has correctly identified itself as an Option 1 company by default (Boston Gas Brief at 75; Exh. KEDNE/PJM-14, at 7; Tr. 25, at 3512-3513). The Company conducted a search of its files and was unable to locate any documentation that would indicate that it had affirmatively designated itself as an Option 2 company (Boston Gas Brief at 75). Because companies that do not affirmatively designate an option default to Option 1, the Company determined that it would be appropriate to apply Option 1 treatment for ITCs in its schedules in this proceeding (Boston Gas Brief at 75). Accordingly, the Company concludes that it appropriately deducted the balance of $1,738,838 in unamortized post-1970 ITCs from rate base and did not reduce its income tax calculation for the annual amortization of the ITC (Boston Gas Brief at 75).

In the alternative, Boston Gas states that if the Department adopts the Attorney General's position and deduct the ITC amortization of $842,004 from the Company's income tax calculation, the Department must also make a corresponding increase to rate base of

$1,713,838, representing the elimination of unamortized ITCs from rate base (Boston Gas Brief at 76). Boston Gas states that this treatment would bring the Company into accord with the Internal Revenue Code (Boston Gas Brief at 76).

3. Analysis and Findings

The Department's ratemaking treatment for ITCs generated prior to 1971 requires amortization of the ITCs and to include the unamortized balance as an offset to rate base. D.P.U. 92-210, at 88; North Attleboro Gas Company, D.P.U. 86-86, at 15-16 (1986); AT&T Communications of New England, D.P.U. 85-137, at 25 (1985); New England Telephone and Telegraph Company v. Department of Public Utilities, 360 Mass. 443, 461-462 (1971). ITCs generated after 1970 are treated for ratemaking purposes in accordance with the requirements of the Internal Revenue Service.

Although Boston Gas states that it was unable to find any documentation that it had elected Option 2, this absence of documentation does not necessarily, without other evidence, lead to the conclusion that the Company defaulted to being an Option 1 company. The Company was required to make a one-time election for ratemaking purposes of its preferred treatment of ITCs earned after 1970 (i.e., it was required to select either Option 1, Option 2 or Option 3 or, absent an affirmative choice, it was assigned Option 1 status by default). Once made, the selection of ratemaking treatment option cannot be changed. At the Company's request, the Department has treated Boston Gas as an Option 2 company for at least the last

fifteen years (Tr. 25, at 3513-3517).[50] Moreover, as the Company acknowledges, if Boston Gas is an Option 1 company, the Department's inclusion of the amortization of ITCs in the calculation of income tax expense for cost of service purposes would constitute a violation of the normalization requirements of the Internal Revenue Code (Tr. 19, at 2623; Tr. 25, at 3517). The Company, however, has never been cited by the Internal Revenue Service for any such violation (Tr. 25, at 3517). On this basis, the Department concludes that Boston Gas is, and always has been, an Option 2 company.

Therefore, we will treat Boston Gas as an Option 2 company for ratemaking purposes and include the $842,004 test year amortization of ITCs in the Company's income tax calculation, as provided in Schedule 8 of this Order. Consistent with this treatment as an Option 2 company, the Department will make a corresponding increase to rate base equal to the Company's post-1970 unamortized ITCs. The entire balance of the Company's unamortized ITCs ($1,713,838) relate to post-1970 activities (Exhs. AG 1-2B(8)(a) at 33; DTE 7-18). Accordingly, the Company's proposed rate base will be increased by $1,713,838.

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[50] The revenue requirement calculations contained in four of the Company's five prior rate cases explicitly include amortization of ITCs in the calculation of income taxes. D.P.U. 96-50 (Phase I) at 394; D.P.U. 93-60, at 497; D.P.U. 88-67 (Phase I) at 434; Boston Gas Company, D.P.U. 1100, at 174 (1982). Because the Department accepted a settlement offer on the revenue requirements in Boston Gas Company, D.P.U. 90-17/18/55 (1990), there are no revenue requirement schedules attached to that Order.

I. Refundable Construction Advances

1. Introduction

Refundable customer advances are advances made by customers to cover the cost of constructing new facilities required to serve the customer, but unlike the case with contributions in aid of construction ("CIAC"), are refunded to customers upon the completion of construction. D.T.E. 02-24/25, at 63; Hingham Water Company, D.P.U. 1590, at 10 (1984). As of the end of the test year, the Company had on its books $50,855 in refundable customer advances (Exh. KEDNE/PJM-2 [rev. 2] at 38). Boston Gas considered these advances as accounts payable and, therefore, did not deduct them from rate base (Tr. 1, at 16).

2. Positions of the Parties

a. Attorney General

The Attorney General states that Department precedent requires utilities to deduct cost-free sources of capital, including refundable construction advances and unclaimed funds, from rate base (Attorney General Reply Brief at 16-17, citing D.T.E. 02-24/25, at 66; D.P.U. 96-50 (Phase I) at 390; D.P.U. 1590, at 10. The Attorney General contends that because the Company has these funds available for use at no cost, as is the case with accumulated deferred income taxes, Boston Gas should be required to deduct its refundable construction advances from rate base (Attorney General Brief at 34).

b. Boston Gas

The Company contends that it first received refundable construction advances from its customers during 2002 (Boston Gas Brief at 33). Boston Gas argues that because these

advances are refundable to customers provided the customer meets certain growth goals, the advances are properly included in rate base (Boston Gas Brief at 33).

3. Analysis and Findings

Refundable construction advances are considered by the Department as an offset to rate base. D.T.E. 02-24/25, at 66; D.P.U. 1590, at 10. Boston Gas' claim that refundable construction advances are akin to accounts payable fails to address the fact that the advances represent a cost-free source of capital to the Company. Moreover, the fact that Company first received refundable construction advances during the test year is irrelevant to either the nature of the advances or their appropriate ratemaking treatment. Accordingly, the Department will reduce the Company's proposed rate base by $50,855.

IV. OPERATING EXPENSES

A. Payroll Expense

1. Introduction

During the test year, Boston Gas incurred a total payroll expense of $105,714,985, of which $75,433,725 was booked to O&M (Exh. KEDNE/PJM-2 [supp.] at 17). The Company proposes to increase its test year union payroll expense by $2,830,121 and to increase its test year non-union payroll expense by $1,145,391 (Exh. KEDNE/PJM-2 [rev. 2] at 6-7).[51]

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[51] The Company initially proposed a one percent "banding adjustment" which added $1,408,642 to its proposed test year non-union payroll increase (Exhs. KEDNE/JCO-1, at 7; KEDNE/PJM-2, at 7). On August 12, 2003, Boston Gas filed revised cost of service schedules that removed this "banding adjustment" pursuant to a July 25, 2003 Keyspan decision to eliminate the adjustment from the O&M budget (Exhs. KEDNE/JCO-3 [rev.]; KEDNE/PJM-2 [rev. 2]; Tr. 16, at 2051-2052).

The Company's proposed union payroll increase consists of: (1) a 2002 Boston Gas union wage increase of 0.73 percent, totaling an annualized amount of $263,364; (2) a 2003 Boston Gas union wage increase of three percent, totaling $1,090,218; (3) a 2004 Boston Gas union wage increase of $924,541;[52] (4) a 2002 Keyspan Services union increase of 0.95 percent, totaling an annualized amount of $101,194; (5) a 2003 Keyspan Services union increase of 3.54 percent, totaling $380,662; and (6) a 2004 Keyspan Services union increase of 0.63 percent, totaling $70,143 (id. at 6). The Company's proposed non-union payroll increase consists of: (1) a 2002 Boston Gas non-union wage increase of 0.67 percent, totaling an annualized amount of $33,272; (2) a 2003 Boston Gas non-union wage increase of 2.5 percent, totaling $124,982; (3) a 2002 Keyspan Services non-union payroll increase, effective April 1, 2002, of 0.88 percent, totaling an annualized amount of $186,031; (4) a 2003 Keyspan Services non-union payroll increase, effective October 1, 2003, of 3.33 percent, totaling $710,153; and (5) a 2004 Keyspan officer wage increase, effective March 1, 2004, of 3.5 percent, totaling $90,953 (id. at 7).

In support of its union payroll increases, Boston Gas included a 2002 union employee salary survey performed by the American Gas Association ("AGA"). The AGA union study compared the median hourly rate and average annual bonus paid to a variety of job categories for union employees of utilities in the Northeast region to the average hourly rate and actual bonus paid to the same job categories for Boston Gas (Exh. KEDNE/JCO-7). In addition, the

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[52] Boston Gas has only included those union payroll increases in 2004 that will take effect through the midpoint of the rate year (i.e., prior to April 30, 2004) (Exh. KEDNE/PJM-1, at 7).

Company performed a comparison of contractual wage increases by percentage for eleven Northeast gas utilities for the period 1993 through 2003 (Exh. KEDNE/JCO-8).

In support of its non-union payroll increase, Boston Gas provided a historical correlation of non-union and union wage increases (Exh. KEDNE/JCO-4 [rev.]). The Company also provided the results of an AGA 2002 compensation survey, which compared actual salaries for Boston Gas and Keyspan to those for Northeast gas companies for a variety of job categories (Exh. KEDNE/JCO-9, at 1, 3). The Company also provided the results of a William Mercer 2002 compensation survey ("Mercer survey"), which compared Boston Gas' actual salaries to general industry salaries within the greater metropolitan Boston area for a variety of job categories (id. at 2). The Mercer survey also compared Keyspan's actual salaries to general industry salaries within the greater metropolitan New York area for a variety of job categories (id. at 4). In addition, the Company conducted a 2001 compensation analysis, which compared compensation per employee for Boston Gas to that of 14 New England gas and electric utilities (Exh. KEDNE/JCO-12).

2. Position of the Parties

a. Attorney General

The Attorney General contends that the Department should disallow the Company's proposed non-union wage increase because it is unreasonable in light of the Company's already relatively high non-union wage levels (Attorney General Brief at 64). The Attorney General avers that the Company has failed to demonstrate that the proposed non-union wage increase is reasonable (id. at 65). The Attorney General argues that the comparison of total average

compensation per employee provided by the Company shows that Boston Gas' non-union employees already earn 6.3 percent more than employees at other New England gas companies (id.). Therefore, the Attorney General argues that allowing the proposed non-union wage increase would drive the Company's non-union compensation further above and out of line with the wages of employees of other New England gas companies (id.).

The Attorney General also claims that there are miscalculations in the comparative analysis of employee compensation, and that these miscalculations hinder the Department's ability to assess the reasonableness of the Company's proposed increase (id. at 65-66). Specifically, the Attorney General references the Company's admitted mislabeling of various median hourly rates as "average" hourly rates (id. at 66, citing Exh. KEDNE/JCO-7; Tr. 16, at 2084-2088, 2092-2096). The Attorney General contends that this error renders the comparison analysis useless and casts doubt on the accuracy of the remainder of the Company's employee compensation analyses (id.).

Finally, the Attorney General argues that the Company "cast an overly broad net" in choosing the New England utility companies it included in its comparison of total compensation per employee (id.). The Attorney General asserts that the inclusion of electric companies in the comparison inflated the average total compensation per employee to $96,285, versus $77,811 for gas companies alone (id.). The Attorney General argues that electric and gas workers are not interchangeable, and that the Company has failed to demonstrate that the most appropriate comparison group in this case is anything other than local gas utilities (Attorney General Reply Brief at 38, n.30). The Attorney General claims that if one were to

remove electric companies from the comparison, the level of the Company's compensation per employee would be above the average (Attorney General Brief at 66).

Regarding Boston Gas' argument that the disparity between its non-union wages and those of other local gas utility employees is justified because its employees are more efficient, the Attorney General responds that the Company has not proven that its employees are more efficient than other local utility employees or that the Company's operations are so efficient as to offset any higher employee compensation costs (Attorney General Reply Brief at 39). For these reasons, the Attorney General urges that the Department to reject the Company's proposed non-union wage increase (Attorney General Brief at 66).

b. Boston Gas

The Company states that it has met the Department's conditions for approving its proposed wage increases (Boston Gas Brief at 51-53). The Company claims that the increases are known and measurable because they are contained in currently effective collective bargaining agreements (id. at 51-52). In addition, the Company notes that the proposed increases will all take effect before the mid-point of the rate year (id. at 51).

The Company asserts that its two surveys comparing union wage expense levels and payroll increases demonstrate that the proposed union payroll adjustments are reasonable (id. at 52). The Company avers that the AGA's 2002 union compensation survey indicates that the median hourly rate of $24.13 paid by other Northeast utilities (with bonuses of $1,900 on average for utilities that paid bonuses), is consistent with the average hourly rate per position of $24.39 (with bonuses of $150) paid by Boston Gas (id.). The Company argues that its

mislabeling of median hourly rates as average hourly rates does not render this comparison improper (id. at 52, n.31). Boston Gas also claims that the survey it provided comparing historical wage increases (on a percentage basis) for union employees of the eleven New England local distribution companies ("LDCs") for the period 1993 through 2003 also affirms the reasonableness of the proposed union wage increase (id. at 53).

Regarding the Company's proposed non-union wage increases, Boston Gas contends that the proposed wage increases are known and measurable and reasonable, and should be approved by the Department (id. at 106). The Company states that management has expressly committed to grant the proposed non-union wage increases (id. at 107, citing Exhs. KEDNE/JCO-1, at 6-7; KEDNE/JCO-3). The Company avers that it has established the requisite historical correlation between union and non-union wage increases, having provided the correlation for an eleven-year period ending in 2003 (id. at 108, citing Exh. KEDNE/JCO-4 [rev.]). According to the Company, its analysis shows that both Boston Gas and Keyspan Services have consistently increased non-union wages over the historical periods at levels comparable to the union increases (id.).

The Company also contends that it has established that the proposed non-union wage increase is reasonable (id.). The Company asserts that the two surveys it provided comparing the salary expense levels and payroll increases for non-union employees demonstrate the reasonableness of the proposed increase (id.). The Company states that the salaries and total compensation for Boston Gas' management employees are comparable to those of Northeast LDCs and non-utility companies in the greater Boston area (id. at 109, citing Exh.

KEDNE/JCO-9). The Company also states that the salaries and total compensation for New York-based Keyspan positions compare favorably with those of Northeast LDCs and non-utility companies in the New York metropolitan area (id. at 109, citing Exh. KEDNE/JCO-9). Finally, the Company argues Boston Gas' merit increases (on a percentage basis) for non-union employees in 2002 and 2003 are consistent with the average increases of other utility and non-utility companies for the same period (id., citing Exh. KEDNE/JCO-10).

Regarding the Attorney General's arguments pertaining to alleged flaws in the Company's comparison analyses, the Company counters that these claims have no merit (id. at 113). First, the Company states that the study the Attorney General claims is "flawed" is a study that supports the Company's union wage levels, not management wage levels (id.). Boston Gas contends that, in arguing that the entirety of the Company's compensation analysis should be disregarded, the Attorney General ignores all of the studies and evidence that the Company presented and focuses, instead, on a labeling error that Company made with respect to union wages (id. at 114). Boston Gas states that it provided several studies comparing the Company's non-union employee compensation to that of both regulated and general industry companies, each of which demonstrate that the Company's non-union wages are at levels consistent with those offered by the comparison companies (Boston Gas Reply Brief at 84, citing Exhs. KEDNE/JCO-9; KEDNE/JCO-10; AG 10-1 [confidential]; AG 10-8 [confidential]).

The Company disputes the Attorney General's claim that the Company "cast too broad a net" in its comparison of wage levels by including electric companies (Boston Gas Brief at 114). The Company argues that the Department has not directed utility companies seeking to establish the reasonableness of their wages in the context of a rate case to compare their wage levels only to companies that sell the same energy commodity (id.). Rather, the Company argues that the Department has allowed utilities to compare their wage levels to other regulated and non-regulated companies that compete for the same employees as the utility performing the comparison, whether or not such utility companies sell the same commodity as the petitioning utility (id., citing D.T.E. 01-56, at 57; D.T.E. 02-24/25, at 95; see also Boston Gas Reply Brief at 83). In addition, the Company argues that Boston Gas functions as part of a multi-state holding company that includes both electric and gas utilities and that the Company's management personnel include individuals from both industries (Boston Gas Brief at 115). The Company argues that this corporate structure is an indication that it competes directly with electric utilities to attract similarly skilled employees (id.).

Also, the Company asserts that Boston Gas is an above average cost performer in the Northeast gas industry (id., citing Exh. KEDNE/LRK-3). Further, to the extent that the Company's compensation levels are, as the Attorney General alleges, higher than either the average or the median level of the peer group, Boston Gas argues that the record shows that the efficiency of the Company's operations offsets any higher employee compensation (id. at 115-116; Boston Gas Reply Brief at 84). For these reasons, the Company states that the Department should reject the Attorney General's argument that Boston Gas should compare its

wage levels only to local gas distribution companies in New England in order to determine the reasonableness of its non-union wage increases (Boston Gas Brief at 115).

3. Analysis and Findings

The Department's standard for union payroll adjustments requires that three conditions be met: (1) the proposed increase must take effect before the midpoint of the first twelve months after the rate increase; (2) the proposed increase must be known and measurable, i.e., based on signed contracts between the union and the company; and (3) the company must demonstrate that the proposed increase is reasonable. D.P.U. 96-50 (Phase I) at 43; Massachusetts Electric Company, D.P.U. 95-40, at 20 (1995); D.P.U. 92-250, at 35; Western Massachusetts Electric Company, D.P.U. 86-280-A at 74 (1987).

To recover an increase in non-union wages, 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) at 42; D.P.U. 95-40, at 21; Fitchburg Gas and Electric Light Company, D.P.U. 1270/1414, at 14 (1983). In addition, non-union salary increases that are scheduled to become effective no later that six months after the date of the Order may be included in rates. Boston Edison Company, D.P.U. 85-266-A/271-A at 107 (1986).

In determining the reasonableness of a company's employee compensation expense, the Department reviews the company's overall employee compensation expense to ensure that its employee compensation decisions result in a minimization of unit-labor costs. D.P.U. 96-50 (Phase I) at 47; D.P.U. 92-250, at 55. This approach ensures and recognizes that the different

components (e.g., wages and benefits) are to some extent substitutes for each other, and that different combinations of these components may be used to attract and retain employees. The Department also requires companies to demonstrate that they have minimized their total unit-labor cost in a manner that is supported by their overall business strategies. D.P.U. 92-250, at 55. However, the individual components of a company's employment compensation package are appropriately left to the discretion of a company's management. Id. at 55-56.

To enable the Department to assess the reasonableness of a company's total employee compensation expense, companies are required to provide comparative analyses of their employee compensation expenses. D.P.U. 96-50 (Phase I) at 47. Both current and total compensation expense levels and proposed increases should be examined in relation to other New England investor-owned utilities and to companies in a utility's service territory that compete for similarly skilled employees. Id.; D.P.U. 92-250, at 56; Bay State Gas Company, D.P.U. 92-111, at 102-103 (1992); D.P.U. 92-78, at 25-26.

With respect to the Company's union payroll increases, the proposed adjustments appropriately include only those increases that have been granted or will be granted before the midpoint of the first twelve months after the Department's Order in this proceeding (i.e., May 1, 2004) (Exh. KEDNE/PJM-1, at 8). Because the union payroll increases are based on signed collective bargaining agreements, the Department finds that these proposed increases are known and measurable (Exh. AG 1-42).

To address the requirement that there be a historical correlation between union and

non-union wages, the Department evaluates the relationship between union and non-union increases. D.T.E. 01-56, at 56; D.P.U. 96-50 (Phase I) at 42. Annual union wage increases granted between 1993 and 2003 have ranged between 2.5 percent and 4.5 percent (Exh. KEDNE/JCO-4 [rev.]). At the same time, annual non-union salary increases have ranged between zero percent[53] and four percent (id.). Union wages increased by three percent in both 2002 and 2003 (id.). Non-union wages increased by 2.75 percent in 2002 and 2.5 percent in 2003 (id.). Based on this evidence, the Department finds that a sufficient correlation exists between union and non-union wage increases. See Essex County Gas Company, D.P.U. 87-59-A at 18 (1988).

Finally, Boston Gas provided survey results that indicate that the hourly rates paid to the Company's union employees are comparable to the hourly average rates of other gas and electric utilities in the Northeast (Exh. KEDNE/JCO-7). The Attorney General has taken issue with the fact that Boston Gas mislabeled median hourly wage values as "average" hourly wages. While the Department recognizes that the distinction between "median" and "average" is significant in terms of statistical analyses, we are not convinced that this error renders this comparison, or other comparative analyses provided by the Company related to union and non-union wages, valueless for our purposes here. Although the union survey results do not provide an "apples to apples" comparison of hourly wages, Department precedent requires the Company to demonstrate that proposed union wage increases are reasonable. The union

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[53] In 1997, the Company did not give a merit percentage increase to its non-union employees; instead, non-union employees were eligible for a three percent lump sum payment (Exh. KEDNE/JCO-4 [rev.]).

survey results certainly demonstrate that the Company's union hourly wages are reasonable compared to other gas and electric utilities in the Northeast (id.).[54] In addition, Boston Gas provided a comparison of contractual wage increases by percentage between itself and other gas utilities in the Northeast between 1993 and 2003 (Exh. KEDNE/JCO-8). This analysis also demonstrates that the Company's proposed union wage increases are reasonable. Having found that the proposed union wage increases (1) take effect before the midpoint of the twelve months after the rate increase, (2) are known and measurable, and (3) are reasonable, the Department will allow the Company to adjust its test year cost of service for the union payroll increases.

With respect to the Company's non-union payroll increases, the proposed adjustments appropriately include only those increases that have been granted or will be granted before the midpoint of the first twelve months after the Department's Order in this proceeding (Exh. KEDNE/JCO-3, at 2; Tr. 16, at 2152-2156). Because management has expressly committed to granting another non-union payroll increase on October 1, 2003 and a management wage increase on March 1, 2004, the Department finds that these proposed increases are known and measurable (Exh. KEDNE/JCO-3, at 2; Tr. 16, at 2152-2156).

In support of the historical correlation between union and non-union raises, Boston Gas provided a comparative analysis of union and non-union wage increases since 1993

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[54] Although not raised by the Attorney General in the context of union payroll increases, he does object to the fact that the Company's 2001 compensation analysis included electric utilities as well as gas utilities (Attorney General Brief at 66). We discuss this issue below.

(Exh. KEDNE/JCO-4 [rev.]). This analysis demonstrates that union and non-union wage increases have been very closely tied between 1993 and 2002. Therefore, the Department finds that there is a sufficient historical correlation between union and non-union wage increases.

To demonstrate the reasonableness of the non-union wage increase, Boston Gas provided the results of an AGA survey, which compared actual salaries for Boston Gas and Keyspan to those for Northeast gas companies for a variety of job categories (Exh. KEDNE/JCO-9, at 1, 3). The Company also provided the results of the Mercer survey, which compared Boston Gas' actual salaries to general industry salaries within the greater metropolitan Boston area for a variety of job categories, and also compared Keyspan's actual salaries to general industry salaries within the greater metropolitan New York area for a variety of job categories (id. at 2, 4). In addition, the Company conducted a 2001 compensation analysis, which compared Boston Gas' compensation per employee to that for 14 New England gas and electric utilities (Exh. KEDNE/JCO-12).

The Attorney General takes issue with the fact that the Company's 2001 compensation analysis compared compensation per employee for Boston Gas to gas and electric utilities in New England. Department precedent requires companies, as an aid in determining the reasonableness of proposed non-union wage increases, to provide comparative analyses of the proposed non-union wage increases in relation to other New England investor-owned utilities and to companies in a utility's service territory which compete for similarly skilled employees. See D.T.E. 01-56, at 54-55; D.P.U. 92-78, at 25-26. In this case, the Company has put forth

the argument that the corporate structure in which Boston Gas operates leads to the Company competing directly with both gas and electric utilities for similarly skilled employees. The comparison study provided by the Company only includes employees who work, in some capacity, for Boston Gas, not the electric utility affiliates of Keyspan (Exh. KEDNE/JCO-1, at 18). While the Company did not provide conclusive evidence that the skill sets required for non-union employees are comparable between the electric and gas industries, its evidence was substantial. Moreover, the Department is long familiar with the types of skills that non-union employees, such as management and support staff, would be expected to have. See D.T.E. 02-24/25, at 94. The Department also recognizes that the skills that these employee groups require would be similar across industries. Therefore, the Department finds that in this instance, the comparison study provides sufficiently reliable results for the Company's non-union employees, and we will consider its results in determining the reasonableness of the Company's non-union wage increase. However, in the case of certain employee categories, such as field personnel, the Department recognizes that their skill sets may differ from industry to industry. Therefore a compensation study that includes employees in diverse industries may not necessarily provide a sufficient demonstration of comparability. We take this opportunity to remind companies seeking to rely on comparison studies that include companies in an industry other than that of the petitioning utility, that they must provide sufficient evidence that the employees of the comparison companies are similarly skilled to the employees of the petitioning utility, whether union or non-union. See D.T.E. 01-56, at 54-55; D.P.U. 92-78, at 25-26. Although the Attorney General makes a useful observation, this imperfection does

not, however, vitiate the Company's analysis, despite missed opportunities to improve it. In future, we will expect a § 94 petitioner to present additional evidence to validate any wage comparisons between personnel in its own utility industry and those in a kindred utility industry. In short, the future standard of proof will be higher.

The 2001 compensation analysis demonstrates that the Company's compensation per employee is below the average of the other New England investor-owned utilities. In addition, the AGA survey and the Mercer survey demonstrate that the Company's pay structure, for most job categories, is below that of the comparison group (Exh. KEDNE/JCO-9, at 1-4). Therefore, the Department finds that the amount of the non-union payroll increase is reasonable.

Having found above that the proposed non-union wage increases (1) are known and measurable, (2) indicate a historical correlation between union and non-union wage increases, and (3) are reasonable, the Department will allow the Company to adjust its test year cost of service for the non-union payroll increases. The total union and non-union payroll adjustments increase test year payroll expense by $3,975,512 (Exh. KEDNE/PJM-2 [rev. 2] at 6-7).

B. Capitalized Employee Benefits

1. Introduction

During the test year, the Company incurred $105,714,985 in total wages and salaries, of which 28.64 percent, or $30,281,260, was capitalized (Exh. AG 1-40). In addition, during the test year the Company incurred $33,202,006 in total employee benefits, of which 18.45 percent, or $6,124,222, was capitalized (id.).

2. Positions of the Parties

a. Attorney General

The Attorney General argues that the Company failed to capitalize an appropriate level of its employee benefit costs during the test year (Attorney General Brief at 71). The Attorney General states that the Company capitalized 28.64 percent of its wages and salaries during the test year, but only 18.45 percent of it employee benefits (id.). The Attorney General claims that, in the years leading up to the test year, the Company capitalized benefits at an average rate of 94 percent of the rate of capitalization of wages and salaries but, during the test year, capitalized benefits at a rate of only 64 percent of the rate of wages and salaries (id., citing Exh. AG 1-40). As a result, the Attorney General avers that the Company has overstated its O&M expenses included in the test year cost of service (id. at 71-72). The Attorney General contends that the Department should reduce the Company's total cost of service by $3,384,833 to bring the benefits capitalization in line with the capitalization of wages and salaries (id. at 72).

b. Boston Gas

The Company asserts that the Attorney General's proposed adjustment is inappropriate and is not supported by the evidence (Boston Gas Brief at 118). The Company alleges that the rate at which employee benefits are capitalized will vary from year to year based on the type and mix of capital projects that the Company undertakes in any given year and the type and mix of employees engaged in those projects (id.). According to the Company, during the test year a significant amount of labor related to the implementation of the CRIS system was

capitalized and that this project was supported by administrative personnel assigned to Keyspan Services (id.). The Company argues that when an increased portion of Boston Gas' capitalized labor is related to non-construction projects and involves Keyspan Services' employees, the variation in the percentage of capitalized employee benefits will increase from the percentage of capitalized labor expense (id. at 119). The Company avers that this variation coincides with the increase in capitalized labor costs related to non-construction activities and the involvement of a significantly greater number of employees other than field personnel during the test year (id.). The Company states that the Attorney General's proposed adjustment does not give appropriate consideration to the type of employees that were engaged in test year capital projects (id.).

3. Analysis and Findings

The Attorney General asserts that the Company failed to capitalize an appropriate level of its employee benefit costs during the test year.[55] It is clear that the ratio of the capitalization of labor to the capitalization of employee benefits is higher during the test year when compared to the four years prior to the test year (Exh. AG 1-40). The rate at which employee benefits are capitalized will vary from year to year depending on the type and mix of capital projects that a company undertakes in any given year and the type and mix of employees engaged in those projects. During the test year, the Company undertook the conversion of its existing

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[55] Pursuant to the uniform system of accounts ("USOA") for gas companies, payroll and benefit expenses associated with construction are added to the cost of the plant, to be recovered over the life of the plant. 220 C.M.R. § 50.00 et seq. (Gas Plant Instructions 3 and 4).

customer record system to the CRIS, which required the support of administrative personnel assigned to Keyspan (Exh. KEDNE/JFB-1, at 11). The use of Keyspan administrative personnel lead to a greater variation in the percentage of capitalized employee benefits compared to capitalized labor expense during the test year, because employee benefits are a greater share of the compensation for these Keyspan employees.

While the level of capitalization for both labor and employee benefits was higher in the test year than the average level of capitalization between 1998 and 2002, we find that the Company appropriately capitalized labor and employee benefits pursuant to the capital projects that were undertaken during the test year. The divergence between capitalizable payroll and capitalizable benefits that occurred during the test year is not so significant as to render Boston Gas' test year capitalizable benefits ratio as unrepresentative. See Boston Edison Company, D.P.U. 1720, at 55-56 (1983). Accordingly, the Department finds that no adjustment to test year capitalized employee benefits is necessary.

C. Incentive Compensation

1. Introduction

Boston Gas proposes to increase its test year O&M expense by $2,241,721 for an incentive compensation program for both union and non-union employees (Exhs. KEDNE/PJM-1, at 12; KEDNE/PJM-2, at 8). The majority of this increase is related to an accounting adjustment necessitated by an over-accrual of $2,097,330 in incentive compensation expense in 2001 (Exh. KEDNE/PJM-1, at 10). In 2002, the Company reversed the over-accrual by making an entry to reduce incentive compensation expense by $2,097,330

(id. at 10-11). Consequently, Boston Gas proposes to increase test year incentive compensation expenses by $2,097,330 to eliminate the effect of the entry made in 2002 to correct for actual incentive compensation expense levels in 2001 (id. at 11). The remainder of the adjustment is attributable to (1) a $13,866 reduction to test year incentive compensation expense to account for the Company's target liability for incentive compensation due to employee performance in 2002, and (2) an $158,257 increase to test year incentive compensation expense to account for the Company's liability for incentive compensation due to Keyspan Services employee performance in 2002 (id. at 11; Exh. KEDNE/PJM-2, at 8).

The basic structure of the incentive compensation program involves (1) specific performance goals, and (2) financial incentives that are linked to various performance levels (Exh. KEDNE/JCO-1, at 9). The goal structure of the incentive compensation program involves three categories of performance goals: (1) corporate goals; (2) business unit or area-specific goals; and (3) strategic initiative or assessment goals (id.). In 2002, the specific goals for Boston Gas employees include the following: (1) achieving earnings objectives; (2) containing O&M costs; (3) ensuring customer satisfaction; (4) maintaining or improving safety; and (5) developing workforce diversity (id. at 9-10).

The incentive compensation program has an established pay-out scale for each performance goal (id. at 10). If the performance goals, or "targets," are met for the annual performance period, the employee receives 100 percent of the target pay-out amount (id.). In addition, a minimum acceptable level of performance, or "threshold," is established for each goal, as well as a maximum level of performance (id.). For performance at the minimum, or

threshold level, the incentive pay-out is 50 percent of the target pay-out level. If performance is at or above the maximum, the pay-out is two times the target pay-out level (id.). Incentive pay-outs are prorated to the extent that performance falls within the bandwidths (id.).

2. Positions of the Parties

a. Attorney General

The Attorney General argues that the Department should disallow recovery of all or part of the proposed non-union incentive compensation increase because the proposed increase is unreasonable and the Company has not shown that it provides any benefits to customers (Attorney General Brief at 67). The Attorney General argues that, because the Company's average total compensation per employee is above the median level for other New England gas companies, any additional increase to non-union employee compensation is unnecessary and inappropriate (id. at 68). The Attorney General also avers that some of the goals that form the basis for evaluating non-union performance are unreasonable because they are too subjective or the weight attributed to the various goals is disproportionate (id.). In addition, the Attorney General claims that the Company has not shown that several of the performance incentive goals, such as supporting high visibility groups and additional press coverage, provide any benefit to customers (id.). Therefore, the Attorney General asserts that the Department should disallow recovery of the Company's entire proposed non-union incentive increase, or, at a minimum, disallow the payroll adjustment portion of the proposed increase attributable to the subjective goals, disproportionately weighted goals, and goals that provide no benefit to customers (id.).

The Attorney General also claims that the Company failed to capitalize any portion of the incentive compensation program (id. at 72, citing Exh. KEDNE/PJM-2, at 8). The Attorney General suggests that, to the extent that the Department allows any incentive compensation, all determinants should be multiplied by 66.30 percent to calculate the expense-only portion (id., citing Exh. KEDNE/PJM-2, at 9).

b. Boston Gas

Boston Gas argues that its incentive compensation expenses meet the Department's standard for inclusion in the Company's cost of service (Boston Gas Brief at 111). The Company claims that it has shown that these expenses are reasonable in amount (id., citing Exh. AG 6-21). The Company argues the target incentive payments during the test year ($750 for union employees and $22,693 for non-union employees) are consistent with the range of incentive compensation payments paid by other utility companies and approved by the Department (id., citing D.T.E. 02-24/25, at 100). The Company also argues that it has demonstrated that its incentive compensation program is reasonably designed to encourage good employee performance (id. at 111-113). The Company states that the incentive compensation program is designed to motivate employees to perform in a manner that has a positive effect on the Company's ability to provide safe, reliable and cost-effective service to customers, while also contributing to the Company's earnings objectives (Exh. KEDNE/JCO-1, at 9).

The Company argues that "reasonableness" of employee compensation is evaluated on a total compensation basis because different components of employee compensation are

substitutable and may be used in different combinations to attract and retain employees (Boston Gas Brief at 116, citing D.P.U. 93-60, at 122-123). Therefore, the Company states that the Department should reject the Attorney General's claims about the "reasonableness" of the incentive compensation program (id.). In addition, the Company avers that the Department should reject the Attorney General's claims that some of the incentive goals are too subjective or given disproportionate weight and that the Company has not demonstrated a customer benefit, because the Attorney General cites to no evidence or other rational legal or factual basis to support his claim (id. at 116-117).

3. Analysis and Findings

The Department has traditionally allowed incentive compensation expenses (i.e., bonuses) to be included in utilities' cost of service so long as they are (1) reasonable in amount, and (2) reasonably designed to encourage good employee performance. Massachusetts Electric Company, D.P.U. 89-194/195, at 34 (1990). In order for an incentive plan to be reasonable in design, it must both encourage good employee performance and result in benefits to ratepayers. D.P.U. 93-60, at 99. As a rule, if a company's employee performance standards are based at least in part on job performance of the individual employee, rather than based solely on the company's financial performance, the incentive plan is deemed reasonably to encourage good employee performance. The Department has stated that if incentive compensation is tied only to financial performance, the benefit to ratepayers is unclear. D.P.U. 89-194/195, at 34. The Department has also disallowed incentive

compensation for senior management if the company's management failed to show itself worthy of bonuses. D.P.U. 85-266-A/271-A at 110-111.

The Department must first determine whether the payments made under the Company's incentive compensation plan are reasonable in amount. Under the Boston Gas incentive compensation plan, the Company paid a total of $239,182 for union and non-union employees during the test year (Exh. AG 1-35, Att.(d) at 17). Keyspan Services made incentive payments totaling $12,748,218 in the test year, of which 15.9 percent, or $2,026,967, was allocated to Boston Gas (Exhs. KEDNE/PJM-2 [rev. 2] at 8; AG 1-35, Att.(a) at 66). In total, the Company paid $2,266,149 in incentive compensation during the test year through a combination of direct charges and allocations, representing 2.1 percent of the Company's total test year wages of $105,714,985 (Exhs. AG 1-35(a); AG 1-35(d); KEDNE/PJM-2 [supp.] at 17). The Company's incentive compensation plan is similar to those of other utilities competing for similarly skilled employees. See D.P.U. 93-60, at 98-101; D.P.U. 92-111, at 114-115. Therefore, the Department finds the test year payments from the Company's incentive compensation plan are reasonable.

Next, the Department must determine whether the Company's incentive compensation plan is reasonable in design. With respect to the benefits to ratepayers, the incentive compensation plan is one means of achieving the Company's overall goal of building long-term value for customers, shareholders and employees (Exh. KEDNE/JCO-1, at 9). Performance in the categories of containing O&M costs, ensuring customer satisfaction, maintaining or improving safety, and developing workforce diversity provide a direct benefit to ratepayers. In

addition, several incentive categories that, at first glance, may not seem to provide any direct benefit to ratepayers, do, in fact, serve to improve overall service for Boston Gas' ratepayers (Tr. 16, at 2160-2188; RR-DTE-67; RR-DTE-69; RR-DTE-70; RR-DTE-71; RR-DTE-72). For example, the incentive category "Internal Reports Issued" benefits ratepayers because it facilitates and promotes the internal auditing work done by the Company, which serves to control costs within Boston Gas (RR-DTE-67). In addition, the categories "O&M, Human Resources, Benefits" and "Achieve Enporion[56] Savings Net of Fees" also serve to reduce costs for the Company by creating an incentive to reduce O&M expenses (Tr. 16, at 2180-2182). Therefore, the Department finds that the Company's incentive compensation plan is designed in such a way as to provide benefits to ratepayers.

With respect to the design of the program to encourage good employee performance, the Department has questioned the benefit of incentive compensation plans based solely on a company's financial performance. However, that is not the case here. While the Company's financial performance is one aspect of Boston Gas' incentive compensation plan, it is not the sole criterion on which incentive compensation is based. The Company's incentive compensation plan includes a wide array of incentive categories that are unrelated to the Company's overall financial performance, but are designed to encourage activities such as cost-containment which enhances value to customers (Exh. DTE 2-16, Atts.(a),(b)).

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[56] Enporion is a consortium that was established by several utilities in order to consolidate orders and leverage the volume of materials purchased to receive better purchase prices (Tr. 16, at 2182).

In addition, the portion of Boston Gas's incentive compensation plan based on utility operations earnings can be compared to the award provision examined by the Department in D.P.U. 89-194/195, at 34. There, the Department approved an incentive plan structured so that if the company's financial performance met certain goals, employees would be entitled to receive incentive compensation; but other employee performance-related incentive factors would determine the amount of incentive compensation an employee may receive. Id. The portion of Boston Gas' incentive plan based on financial performance is similar in design.

The Attorney General argues that some of the goals in the Company's incentive compensation package are too subjective or disproportionately weighted. However, the majority of the goals that the Attorney General alleges to be too subjective are, in fact, only applicable to employees that do not work for Boston Gas. Because the incentive compensation amounts related to these goals are not allocated to Boston Gas, they need not be addressed in this proceeding (Exh. DTE 2-16, Att.(b)). For the two goals cited by the Attorney General that do apply to Boston Gas employees ("$ Value of DTE Adjustments" and "Capital Market"), the Department finds that these goals are not subjective and are properly weighted. In the first instance, "$ Value of DTE Adjustments," this goal relates to the billing department at Boston Gas. Performance can be clearly tracked based on the number of billing adjustments required by the consumer division of the Department. In the second instance, "Capital Markets," the goal relates to activities such as refinancing of debt. Performance here can be tracked based on target financial market measures set at the outset of the year. Therefore, we find that the Company's overall incentive compensation plan is reasonably designed to

encourage good employee performance. Having found that Boston Gas' incentive compensation plan (1) is reasonable in amount, (2) is reasonably designed to encourage good employee performance, and (3) will result in benefits to ratepayers, we will allow the Company to recover incentive compensation expenses.

The Attorney General argues that a portion of the Company's incentive compensation package should be capitalized, as it was for the transition base pay to variable pay adjustment.[57] According to the Company, its transition base pay to variable pay adjustment is exclusive of capitalized amounts (Exh. KEDNE/PJM-1, at 13). We are unable to distinguish between the incentive compensation adjustment and the transition base pay to variable pay adjustment, which also relates to incentive compensation. However, because the Company expensed 66.3 percent of its incentive compensation related to the transition base pay to variable pay adjustment, it is reasonable to conclude that the broader incentive compensation adjustment should include both a capitalized and an expensed amount. Therefore, the Department directs the Company to expense 66.3 percent of the incentive compensation adjustment, which reduces the adjustment from $2,241,721 to $1,486,261.

D. Base to Variable Pay Transition

1. Introduction

Boston Gas proposes to increase its test year O&M by $297,372 to account for the transition of employee compensation from base pay to variable pay (Exh. KEDNE/PJM-2,

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[57] In the documentation supporting the transition base pay to variable pay, the Company indicated that 66.3 percent of the adjustment related to "Boston Gas Employees Direct" was charged to O&M (Exh. KEDNE/PJM-2, at 9).

at 9). Of this amount, $211,192 is associated with Keyspan Services' non-union employees and $86,180 is associated with Boston Gas' non-union employees. Both amounts are exclusive of capitalized amounts (Exh. KEDNE/PJM-1, at 13).

This adjustment represents test year target incentive compensation costs as the Company continues to transition its Boston-based non-union employees to a wage structure that increases the variable pay share of compensation (id. at 12-13; Tr. 16, at 2150-2152). The transition plan is a three-year plan concluding at the end of calendar year 2003 (Exh. KEDNE/PJM-1, at 12). The transition plan is designed to standardize the wage and salary structure for non-union employees of the regulated gas distribution companies in Massachusetts and New York by raising the incentive-pay opportunities for Boston Gas employees and slowing the pace of their base wage and salary increases (id.; Exh. KEDNE/JCO-1, at 11; Tr. 16, at 2150-2152).

2. Positions of the Parties

a. Attorney General

The Attorney General disputes the inclusion of these incentive compensation-related expenses for the same reasons he opposes the overall incentive compensation program (Attorney General Brief at 67-68). Specifically, the Attorney General argues against the allowance of any incentive compensation increase because the proposed increase is unreasonable and would compound the Company's already excessive compensation (id.; Attorney General Reply Brief at 40).

b. Boston Gas

Boston Gas defends the inclusion of the amounts related to the transition plan as a part of the overall incentive compensation program, based on the same arguments that it put forward to defend the overall incentive compensation program (Boston Gas Brief at 110-117). Specifically, Boston Gas argues that it has demonstrated that its employee compensation expenses meet the Department's standard for inclusion in the Company's cost of service (id. at 111).

3. Analysis and Findings

The transition of Boston-based non-union employees to a wage structure that is more heavily weighted to incentive compensation serves to benefit ratepayers as pay will be tied more to the overall performance of the employee and the Company (Tr. 16, at 2150-2152). In Section IV.C, above, the Department determined that the Company's overall incentive compensation plan is designed to encourage good employee performance. The Department has already determined that the incentive compensation goals set by the Company serve to benefit ratepayers. It stands to reason that if a greater share of an employee's compensation is tied to the incentive compensation goals set by the Company, then the employee will strive to achieve those goals. Provided the goals striven for are customer-service oriented, as they are here, the incentive compensation plan may be appropriate. Based on the above, the Department finds that the Company's proposal to transition Boston-based non-union employees to a wage structure that increases the share of compensation that is variable pay is reasonable.

Therefore, we accept the Company's proposal to increase test year O&M by $297,372 to account for the Company's transition of employee compensation from base pay to variable pay.

E. Dental Expense

1. Introduction

During the test year, the Company booked $977,514 in dental insurance expense (Exh. KEDNE/PJM-2 [supp.] at 16-17). The Company proposes to increase its test year dental insurance expense by $51,432 (Exh. KEDNE/PJM-2, at 10). Of this amount, $50,034 is attributable to a 7.17 percent increase in dental insurance expenses in 2003 for Boston Gas and $1,398 is attributable to a 0.50 percent increase in dental insurance expense in 2003 for Keyspan Services (id.).

The Company argues that its proposed increase to test year dental insurance expense is known and measurable and reasonable in amount (Boston Gas Brief at 54-55). In addition, the Company avers that it has sufficiently demonstrated efforts to contain dental insurance costs (id. at 55, citing Exh. KEDNE/JCO-1, at 12-14). The Company states that it has undertaken cost containment measures in order to minimize its dental expenses including (1) increasing employee contributions and (2) eliminating dental coverage after the age of 65 for union and non-union retirees (Exh. KEDNE/JCO-1, at 14). The Company also claims that the dental insurance cost increases are less than or comparable to the increases generally experienced in the marketplace and are indicative of the strong cost-containment measures implemented by Boston Gas (id. at 15). For these reasons, Boston Gas states that the

Department should allow the Company to include its dental insurance adjustment in its cost of service (Boston Gas Brief at 55).

2. Analysis and Findings

The Department requires that test year dental insurance expenses and post-test year adjustments be (1) known and measurable, and (2) reasonable in amount. D.P.U. 96-50 (Phase I) at 45-46; D.P.U. 86-86, at 8. In addition, the Department requires utilities to contain their dental insurance costs. D.P.U. 96-50 (Phase I) at 46; D.P.U. 92-78, at 29; Nantucket Electric Company, D.P.U. 91-106/138, at 53 (1991). The Company included dental insurance costs for active employees during the test year based on actual premiums (Exh. KEDNE/PJM-2 [supp.] at 16-17). The Company also provided evidence of the increase to dental insurance premiums that occurred in 2003 (Exh. KEDNE/JCO-6). Therefore, these costs are known and measurable.

Concerning the reasonableness of the Company's dental insurance expense, Boston Gas has shown that the increase to dental benefits experienced by Boston Gas and Keyspan employees are lower than the increase generally experienced in the marketplace (Exh. KEDNE/JCO-1, at 14-15). Therefore, the Department finds that the Company's dental insurance expense is reasonable. In addition, Boston Gas has established that it has taken steps to contain its dental insurance costs. Specifically, the Company gas increased employee contributions and eliminated dental coverage after the age of 65 for union and non-union retirees (id. at 14). Because the Company's dental insurance expenses for the test year are both known and measurable and reasonable, and because the Company has taken steps to

contain its dental insurance costs, we accept Boston Gas' proposed adjustment to test year cost of service of $51,432.

F. Health Care Expense

1. Introduction

During the test year, the Company booked $8,790,912 in health insurance expense (Exh. KEDNE/PJM-2 [supp.] at 16-17). The Company proposes to increase its test year health insurance expense by $1,128,502 (Exh. KEDNE/PJM-2, at 11). Of this amount, $771,197 is attributable to a 13.21 percent increase in health insurance expenses in 2003 for Boston Gas and $357,305 is attributable to a 12.10 percent increase in health insurance expense in 2003 for Keyspan Services (id.).

The Company asserts that its proposed increase to test year health insurance expense is known and measurable and reasonable in amount (Boston Gas Brief at 55-57). In addition, the Company also argues that it has sufficiently demonstrated efforts to contain health insurance costs (id. at 56, citing Exh. KEDNE/JCO-1, at 12-15). These measures include the following: (1) redesigning all union and non-union healthcare plans to include increased deductibles, higher office visit co-payments, higher emergency room co-payment amounts, higher hospital admission co-payments, and increased out-of-pocket maximums; (2) consolidating all retail and mail-order prescription drug coverage under one provider, increasing prescription co-payments, establishing a three-tier co-payment structure, and implementing a mandatory mail-order feature for maintenance prescription drugs; (3) increasing employee contributions for health insurance; (4) capping the Company's liability for annual healthcare premiums

relating to union and non-union retirees at $3,375 per retiree and spouse over the age of 65, with retirees paying the full cost of coverage above the caps; (5) eliminating the Company's liability for healthcare coverage after the age of 65 for non-union retirees hired after January 1, 1993; (6) eliminating Fallon and Cigna health maintenance organizations for non-union employees in 2003, and the Blue Choice plan in 2002; (7) making new union employees eligible for healthcare coverage after six months rather than three months; and (8) making non-union employees eligible for healthcare coverage after three months of service rather than after the first month following the commencement of employment (Exhs. KEDNE/JCO-1, at 14; AG 1-52). In addition, in 2003, Keyspan initiated a separate self-insurance plan for drug coverage for its New England employees, including Boston Gas, rather than continuing to pay for drug coverage within the monthly premiums for healthcare plans (Exh. KEDNE/JCO-1, at 12). By implementing this self-insurance plan, Keyspan estimates that it can defray five percent of the incremental cost of including drug coverage in the healthcare plans offered to employees (id.). The Company also claims that the health insurance cost increases that the Company will incur are less than or comparable to the increases generally experienced in the marketplace and are indicative of the strong cost-containment measures implemented by Boston Gas (id. at 15). For these reasons, Boston Gas states that the Department should allow the Company to include its health insurance adjustment in its cost of service (Boston Gas Brief at 57).

2. Analysis and Findings

The Department requires that test year health insurance expenses and post-test year adjustments be (1) known and measurable, and (2) reasonable in amount. D.P.U. 96-50 (Phase I) at 45-46; D.P.U. 86-86, at 8. In addition, the Department requires utilities to contain their health insurance costs. D.P.U. 96-50 (Phase I) at 46; D.P.U. 92-78, at 29; D.P.U. 91-106/138, at 53.

The Company included health insurance costs for active employees during the test year based on actual premiums (Exh. KEDNE/PJM-2 [supp.] at 16-17). The Company also provided evidence of the 2003 increase in health insurance premiums (Exh. KEDNE/JCO-5). Therefore, we find that these costs are known and measurable.

Concerning the reasonableness of the Company's health insurance expense, Boston Gas has shown the increase to health benefits experienced by Boston Gas and Keyspan employees are lower than the increase generally experienced in the marketplace (Exh. KEDNE/JCO-1, at 14-15). Therefore, the Department finds that the Company's health insurance expense is reasonable. Boston Gas has also shown that it has taken steps to contain its health insurance costs. Specifically, among other things, Boston Gas has increased employee contributions for health insurance, capped the Company's liability for annual healthcare premiums relating to union and non-union retirees over the age of 65, with retirees paying the full cost of coverage above the caps; eliminated the Company's liability for healthcare coverage after the age of 65 for non-union retirees hired after January 1, 1993; and eliminated Fallon and Cigna health maintenance organizations for non-union employees in 2003, and the Blue Choice plan in 2002

(id. at 14; Exh. AG 1-52). In addition, in 2003, Keyspan initiated a self-insurance plan for drug coverage for its New England employees, including Boston Gas, rather than continuing to pay for drug coverage within the monthly premiums for its healthcare plans (Exh. KEDNE/JCO-1, at 12). Accordingly, the Department finds that Boston Gas has taken appropriate measures to contain health insurance expenses. Because the Company's health insurance expenses for the test year are both known and measurable and reasonable, and because the Company has taken steps to contain its health insurance costs, we accept Boston Gas' proposed adjustment to test year cost of service of $1,128,502.

G. Severance Adjustment

1. Introduction

The Company proposes to increase its test year O&M expense by $250,000 to eliminate the effect of an adjustment the Company made to its books to reverse amounts associated with the accrual of severance expense (Exhs. KEDNE/PJM-1, at 22; KEDNE/PJM-2, at 19; KEDNE/PJM-2 [supp.] at 110-111). In 2000, the Company implemented a severance program aimed at workforce reductions (Exh. KEDNE/PJM-1, at 22). In that year, the Company booked an accrual to account for the liability associated with the severance program (id.). In 2002, the Company determined that the accrual exceeded the actual cost, and as a result, made an entry on its books in 2002 to reverse the remaining liability, which reduced O&M expense by $250,000 (id.).

The Company asserts that this adjustment was made in accordance with generally accepted accounting principles ("GAAP"), which require that when a company incurs a

liability that is known and measurable, it is required to record that liability (Boston Gas Brief at 60; Exh. DTE-2-35). If the amount is not known, but is reasonably estimable, the company is required to record the estimate (Exh. DTE 2-35). As of the date of the merger with Keyspan in November 2000, Boston Gas had a known liability, which was reasonably estimable at that time, and therefore, it recorded the liability on its books (id.). The Company claims that this proposed adjustment does not affect the revenue requirement (Boston Gas Brief at 60).

2. Analysis and Findings

The proposed adjustment, made in compliance with GAAP, eliminated the effect of an adjustment the Company made to its books to reverse amounts associated with the accrual of severance expense (Exhs. DTE-2-35; KEDNE/PJM-1, at 22; KEDNE/PJM-2 [supp.] at 110-111). The reversal of an accounting entry that was made in the test year has no effect on the Company's revenue requirement because the end result of such an adjustment is a zero cost to ratepayers. Therefore, the Department accepts the Company's proposal to increase its test year O&M expense by $250,000 associated with the accrual of severance expense.

H. "Above and Beyond" Awards

1. Introduction

"Above and Beyond" awards are granted to employees in recognition of superior performance on a special project or other business initiative (RR-AG-100). During the test year, the Company paid $90,494 in "Above and Beyond" awards that were charged to O&M (id.). Of the $90,494, $81,052 is attributable to awards that were allocated from Keyspan

Services to Boston Gas, and $9,442 is attributable to awards that were directly incurred by Boston Gas (id.).

2. Positions of the Parties

a. Attorney General

The Attorney General argues that these costs should be disallowed as they duplicate the existing incentive compensation program and are non-recurring and non-extraordinary expenses (Attorney General Brief at 70). The Attorney General avers that these costs do not meet any of the Department's criteria for inclusion in the cost of service (id.).

b. Boston Gas

Boston Gas views these awards as necessary to provide management with the opportunity to show appreciation to employees who have demonstrated effort, dedication and perseverance in performing their job function, and not as part of an employee's compensation for his or her position (RR-AG-100). The Company states that customers benefit from these awards because the employee receiving the award has produced significant value for the Company in terms of cost management, timely and successful completion of a special project, or other effort on behalf of the Company's service obligation (id.).

Boston Gas disputes the Attorney General's claim that these costs represent one-time, non-recurring expenses (Boston Gas Brief at 117). Boston Gas states that the record shows that it grants these awards periodically in recognition of superior performance on a special project or other business initiative (id., citing RR-AG-100). The Company maintains that,

because such payments recur periodically, the Department should allow such payments to be included in the Company's cost of service (id.).

3. Analysis and Findings

Just like the incentive compensation program, the Department must assess the "Above and Beyond" awards based on the following criteria: (1) whether the awards are reasonable in amount, and (2) whether the "Above and Beyond" awards program is reasonably designed to encourage good employee performance, conducive to good customer service. Because the Company provided no documentation indicating the goals or achievements that must be attained by employees in order to be eligible for an "Above and Beyond" award, it is impossible for the Department to determine if the design of this program or the payments made as a result of this program are reasonable. In addition, Boston Gas did not provide any historical evidence that would indicate that the level of "Above and Beyond" awards granted in the test year is a representative amount. In fact, the only specific instance cited by the Company is the CRIS system, where the suggestion seems to be that this special project would not have been completed on time without extraordinary effort (suggesting, if anything, some failure to manage the project in a routine and sound way) to avoid additional "significant costs to the Company."

The failure is not so much one of concept as of proof, and it may be that such a program could find favor in a future case. The Department finds that Boston Gas has not demonstrated that the amount of "Above and Beyond" awards included in its test year cost of service are either reasonable in amount or a representative level of these expenses. In

addition, given that the Company has argued that its employees are adequately compensated through base salary and incentive compensation, Boston Gas has failed to demonstrate the ratepayer benefit of the "Above and Beyond" awards (Exh. KEDNE/JCO-1, at 4,9). Finally, because no written eligibility criteria exist for the "Above and Beyond" award program, the Department finds that the program is too subjective and, therefore, not reasonably designed to encourage good employee performance. Therefore, the Department disallows the inclusion of the $90,494 of "Above and Beyond" awards that were charged to test year O&M.

I. Officer Expenses

1. Introduction

During the test year, the Company booked $158,846 in officer expenses to O&M (Exh. AG 21-5; RR-AG-93). These expenses were incurred by Keyspan officers and then a portion was allocated to Boston Gas (RR-AG-93). These expenses were for items including entertainment, subscriptions, membership fees and travel expenses (Exh. AG 21-5).

2. Analysis and Findings

In order for expenses such as officer expenses to be included in test year O&M, the Company must demonstrate that these expenses benefit ratepayers. In D.P.U. 92-111, at 154, the Department stated that a company has a responsibility to be prudent in the amount of business travel expenses and the costs of such travel which it expects to be paid for by ratepayers. This standard is also applicable to other expenses, such as officer expenses. In addition, the Department notes that the fact that these expenses were incurred at the parent

company or service company level and then allocated down to Boston Gas does not mean that the Company does not have to meet our standards for inclusion for the individual expenses.

The Company has failed to demonstrate any ratepayer benefit for these costs. There may be some, but it is not shown. Boston Gas has included costs such as memberships to executive airline clubs and dinner engagements that included guests of Company officers,[58] without any showing that these expenses meet the Department's standards for inclusion in cost of service (Exh. AG 21-5; Tr. 25, at 3446-3447, 3451-3452). The Company has also failed to demonstrate that it was prudent with regard to the expenses incurred by its officers or with regard to the amount of those costs that would be charged to ratepayers (Tr. 25, at 3442-3453).

In addition, the Company has requested recovery of officer expenses with such ambiguous descriptions as "entertainment" and "miscellaneous" (id. at 3447-3453). It is impossible for the Department to assess the nature such costs and whether they are appropriately included in cost of service without an adequate description of the expense in question. The Department notes that the Company was alerted to the problematic nature of this record keeping system by the SEC during its audit of Keyspan (Exh. AG 17-33 [supp.] at 15). Therefore, because the Company has not shown that these officer expenses meet our standard for inclusion in cost of service, the Department disallows $158,846 in expenses that were booked to test year cost of service.

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[58] The Department has stated that there is no necessary business reason why a guest must be in attendance at business meetings, and that, therefore, this expense provides no benefit to ratepayers. D.P.U. 92-111, at 153-154.

J. Rate Case Expense

1. Introduction

In its initial filing, Boston Gas estimated it would incur $1,665,289 in rate case expense (Boston Gas Brief at 119; Exhs. KEDNE/PJM-1, at 22; KEDNE/PJM-2, at 20). On September 29, 2003, the Company reported that its total rate case expense was $2,035,423. Boston Gas proposes to amortize the rate case expense over the five-year term of its proposed PBR plan (Boston Gas Brief at 120, citing Exh. KEDNE/PJM-1, at 24).[59]

The Company's rate case expense includes: (1) legal representation; (2) research and preparation of a productivity and cost study to support the price-cap component of the PBR plan; (3) research and preparation of the cost of capital analysis; (4) preparation of a lead-lag study; and (5) other associated costs that were incurred to complete the case, such as temporary office help, office supplies, and travel expenses (id. at 119-120, citing Exh. KEDNE/PJM-1, at 22-23). In addition, the Company seeks recovery of a fixed fee for legal services to complete the rate case compliance phase (Exhs. AG 5-2; AG 5-6 [supp.] [confidential] (Rate Case Expense Summary at 1)).

2. Positions of the Parties

a. Attorney General

The Attorney General argues that the Department should disallow the rate case expense associated with outside legal fees and rate case consultants because Boston Gas did not obtain

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[59] The proposed annual amount of $333,058 was based on the original rate case expense estimate and a five-year PBR plan (Boston Gas Brief at 119-120).

competitive bids or provide adequate justification for failing to do so (Attorney General Brief at 74, 76). Alternatively, the Attorney General contends that Department should disallow at least a percentage of the total rate case legal fees because the Company did not obtain a discount, as well as disallow the legal fees for an earlier "abandoned rate case" based on a 2001 test year (id. at 74-75).

First, the Attorney General advocates the rejection of the Company's rate case legal expense because Boston Gas did not solicit competitive bids for legal services for the rate case (id. at 74). Without competitive bids, the Attorney General argues, the Company had no objective means to determine whether another law firm would charge lower rates or could prepare and present the Company proposal in fewer billable hours (id.).

Further, the Attorney General maintains that because the Company did not seek competitive bids, its claim that it was receiving discounted legal fees should be closely scrutinized (id.). The Attorney General notes that the April 1, 2002 engagement letter for rate case legal services indicates that the Company's law firm promised a discount from the firm's current hourly billing rate (id. at 74, citing Exh. AG 5-2). However, the Attorney General contends that a comparison of legal invoices showing the hourly rate for the rate case with invoices showing the hourly rate for other legal services during the test year reveals no difference in rates (id., citing Exhs. AG 5-6; AG 5-6 [supp.]; AG 1-95 [supp.]). Therefore, the Attorney General concludes that the firm did not actually provide a discount; and, accordingly argues the Department should disallow at least some of the rate case legal expense by applying the promised discount to the total for legal services (id.).

In addition, the Attorney General urges the Department to reject $45,350 in fees for legal work performed on an earlier contemplated rate case, based on a 2001 test year, that the Attorney General claims was abandoned in August 2002 (id. at 75). According to the Attorney General, the Department should not allow as a recoverable expense fees for an abandoned rate case project based on a different test year (id.).

The Attorney General also urges the Department to reject the Company's request to recover expenses associated with outside consultants for the rate case (id. at 76). As with legal services, the Attorney General contends that the Company did not solicit competitive bids for consultants, and consequently there is no objective method to determine whether these services could have been provided at lower cost (id.).

Finally, the Attorney General asserts that the Company needlessly increased rate case expense by filing a case that simultaneously contains materials for a cost of service rate case, a PBR investigation, and a merger review case (id.). The Attorney General argues that consumers would not be faced with such a large rate case expense now, had Boston Gas submitted its filings "in a reasonably coordinated manner" (id.).[60]

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[60] The Attorney General also seeks elimination of legal fees for work related to environmental remediation by the firm Dickstein, Shapiro, Morin and Oshinsky ("Dickstein Shapiro"), because the Company did not send out for competitive bidding for this work (Attorney General Brief at 75, citing RR-AG-95; see also Tr. 14, at 1880-1883). Rather, the Attorney General, claims, the work was awarded to a Company insider, Frederick Lowther, who is both a law partner at Dickstein Shapiro and director of Keyspan Energy Development Corporation (id., citing Exhs. AG 1-93; AG 1-95; AG 1-98; see also Tr. 14, at 1883). As discussed below, these legal fees were not rate case-related.

b. Boston Gas

Boston Gas defends its rate case expense as known, measurable, reasonable in amount, and properly included in the Company's cost of service (Boston Gas Brief at 120, 123, citing Exh. KEDNE/PJM-1, at 22-24; Tr. 14, at 1872-1875). Boston Gas argues that its decision to retain legal and consulting services for this proceeding without a competitive bidding process is appropriate and reasonable, because the law firm and consultants it engaged the are in the best position to provide the Company with cost-effective services (id. at 120, citing Exh. KEDNE/PJM-1, at 24; Tr. 14, at 1872). Further, the Company asserts that, even if it did send out for competitive bids, it would not be required to hire the lowest bidder unless the Company "felt it would be appropriate" (Tr. 14, at 1874).

The Company states that its law firm has a longstanding working relationship with Boston Gas and its distribution company affiliates through several major proceedings, including the acquisitions by Eastern Enterprises of both Essex and Colonial, and the firm has expertise in utility and regulatory matters in Massachusetts (Boston Gas Brief at 120-121; Exh. KEDNE/PJM-1, at 24-25; Tr. 25, at 3481-3482). Therefore, Boston Gas asserts, its legal counsel has thorough knowledge of the Company's corporate structure, finances, operations, and ratemaking practices (Boston Gas Brief at 121, citing Exh. KEDNE/PJM-1, at 24).

Likewise, Boston Gas argues that the consultants it used also have a longstanding relationship with the Company and substantial and unique expertise in utility ratemaking (id. at 122, citing Exh. KEDNE/PJM-1, at 24). Further, Boston Gas states that it sought to contain

its legal and consulting rate case expenses by using in-house resources and employees for as much of the rate case work as possible and resorting to outside consultants only when necessary (Attorney General Brief at 121; Tr. 25, at 3482-3484).

Boston Gas disputes the Attorney General's arguments challenging specific Company rate case expenses. Responding to the Attorney General's assertion that it should have competitively bid its legal services, Boston Gas states that it has provided sufficient rationale to establish that its use of longstanding regulatory counsel was cost-effective and reasonable (Boston Gas Brief at 121). The Company also disputes the Attorney General's implication that another consultant could have prepared a productivity analysis more efficiently (id.). Boston Gas asserts that the consultant who developed the Company's productivity analysis for its last rate case, D.P.U. 96-50, was uniquely situated to update the Company's 1996 study for the present rate case. The Company argues that use of another consultant who did not have access to the existing proprietary database and modeling routine would have made preparation of the productivity analysis more costly (id. at 122-123).

Regarding the discount for legal services, the Company argues that the Attorney General's conclusion that the discount was not applied is erroneous (id. at 121). Boston Gas notes that the agreement it reached with legal counsel shows that the law firm offered to provide services for the rate case at a discount from the firm's "current billing rate" (id. at 121, citing Exh. AG 5-2, Tr. 25, at 3481-3488, 3499-3500). According to Boston Gas, the Company received the same discount from the law firm's regular billing rates for other regulatory matters in 2002, and thus, comparison of the billing rates for various legal work

does not, as the Attorney General alleges, reveal the absence of a discount (Boston Gas Brief at 121-122).

Further, Boston Gas asserts that the Attorney General misinterpreted notations on legal invoices referring to "2001 Rate Case" (id. at 122, n.47, citing Attorney General Brief at 75; Exh. AG 5-6, at 76-88). According to the Company, Boston Gas investigated the necessity of filing a rate case in 2002, but decided against it (Boston Gas Brief at 122, citing Tr. 12, at 1541-1542). However, Boston Gas maintains that the work performed by regulatory counsel on the contemplated 2002 rate case filing is indistinguishable from work related to the Company's current rate case; i.e., all of the work was "carried over" for use in the rate case ultimately filed (id.). Therefore, Boston Gas argues that it has properly included these expenses in its cost-of-service calculation (id.). Finally, Boston Gas asserts that the Department should approve the Company's proposal to amortize rate case expenses over the five-year period of its proposed PBR plan (id. at 123, citing D.P.U. 96-50 (Phase I) at 78-79).

3. Analysis and Findings

a. Introduction

The Department allows recovery for rate case expenses if the expenses are known and measurable. D.T.E. 01-56, at 75; Dedham Water Company, D.P.U. 84-32, at 17 (1984). The overall level of rate case expense among utilities has been, and remains, a matter of concern for the Department. D.T.E. 02-24/25, at 192; D.T.E. 98-51, at 57; D.P.U. 96-50 (Phase I) at 79. The Department has cautioned companies that rate case expense, like any other expenditure, is an area where companies must seek to contain costs. D.T.E. 02-24/25, at

192; ; D.P.U. 96-50 (Phase I) at 79. Below, we address the issues of competitive bidding, the legal services discount, the question of the un-filed rate case planned for 2002, supporting invoices for consultant expenses, miscellaneous rate case expenses, the fixed legal fee for the completion of the compliance phase, and the normalization period for rate case expense.

b. Competitive Bidding

The Department has repeatedly admonished companies to contain rate case expenses, and that obtaining competitive bids for consultant services is an important part of containing this expense. In an effort to control these costs, the Department has stated that we will approve expenses for outside legal and consulting services not competitively bid only if the company provides adequate justification for its decision to forgo the bidding process. D.T.E. 02-24/25, at 192; D.T.E. 01-56, at 76; D.T.E. 98-51, at 59-60; D.P.U. 96-50 (Phase I) at 79. For example, in Boston Gas' last rate case, the Department stated:

> The Department has been increasingly concerned with the level of rate case expense among utilities in general, and specifically noted such in the Company's last rate case. D.P.U. 93-60, at 145; see also D.P.U. 92-111, at 208; D.P.U. 92-78, at 58. A certain amount of litigation expenses are properly within management's control. As a result, rate case expense, like any other expenditure, is an area where companies should seek to contain costs. The Department has attempted to evaluate each company's efforts to control costs, such as its use of outside legal and consulting services. If a company does elect to secure outside services, the Department expects a company to engage in a competitive bidding process for these services. If a company forgoes the competitive bidding process, a company must provide adequate justification of its decision to do so.

D.P.U. 96-50 (Phase I) at 79. However, the Department observes that companies are increasingly choosing to forgo the competitive bidding process and, instead, relying on Department approval of outside consulting and legal expenses where a company asserts a

long-time working relationship with a particular consultant.[61] In this case, Boston Gas asserts this justification for its failure to solicit any competitive bids for outside rate case services.

Boston Gas argues that it was justified in forgoing competitive bidding and retaining the legal counsel that has performed its regulatory work for some time because the law firm's knowledge of the corporate structure and operations of Boston Gas and Keyspan and working relationship with the Company made the firm the most cost-efficient choice (Boston Gas Brief at 120; Exh. KEDNE/PJM-1, at 24-25; Tr. 14, at 1874-1875; Tr. 25, at 3481-3482).[62] Further, Boston Gas asserts that it obtained a discount on its rate case legal services (Boston Gas Brief at 121-122; Exh. AG 5-2).

Boston Gas argues that it was also justified in engaging its outside consultants without undergoing a competitive bidding process due to their working relationship with the Company and expertise in utility matters (Boston Gas Brief at 122-123; Exh. KEDNE/PJM-1, at 25). The Company states that, with the exception of the lead-lag study consultant, the consultants retained for this proceeding are familiar with the Company's operations and have participated in its past rate cases (Tr. 14, at 1873-1875; Tr. 24, at 3301-3302; Tr. 25, at 3383-3386).[63]

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[61] For example, in Fitchburg's last rate case, only two of the consultants for five consulting services was competitively bid. D.T.E. 02-24/25, at 54, 133, 192-194. In Berkshire's last rate case, the company sought competitive bids for only one of five consultants. D.T.E. 01-56, at 47, 75-77.

[62] However, we note that the legal counsel engaged by Boston Gas in this proceeding was not its counsel in the prior rate case proceeding (Tr. 25, at 3481).

[63] In the case of the lead-lag study consultant, the Company did not "formally" solicit competitive bids for this service. Instead, it obtained "verbal quotations" from

(continued…)

The Company asserts that its PBR expert supported Boston Gas' PBR proposal in its previous rate case, D.P.U. 96-50; and the cost of equity expert assisted the Company in past cases, is knowledgeable about the Company's operations and finances, and has testified on behalf of other utilities in Massachusetts (Boston Gas Brief at 122-123; Exh. KEDNE/PJM-1, at 25).

In presenting these justifications for forgoing the competitive bidding process, Boston Gas relies on two recent rate case decisions for Fitchburg and Berkshire in D.T.E. 02-24/25 and D.T.E. 01-56, respectively (Boston Gas Brief at 120). The Department found that Fitchburg adequately supported its decision to forgo competitive bidding for its cost of capital and cost of service studies, and its outside legal services.[64] D.T.E. 02-24/25, at 192-193. Likewise in D.T.E. 01-56, the Department found that Berkshire adequately justified its decision to retain its law firm and outside consulting services regarding rate design,

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[63] (…continued)
accounting firms for comparison to the fee of the consultant it selected, found the consultant's fee to be reasonable, and entered into a fixed price contract with the consultant (Tr. 25, at 3383-3386).

[64] In D.T.E. 02-24/25, at 192, citing D.T.E. 98-51, at 61, the Department noted that it had previously directed Fitchburg to "provide adequate justification of every instance where it decided not to use the competitive bidding process. [Fitchburg] was further warned that failure to do so would result in disallowance of that portion of rate case expense." In accepting Fitchburg's decision to forgo the competitive bidding process, the Department found that the cost of capital and cost of service consultants had "an extensive working relationship with [Fitchburg], had developed similar studies in the [Fitchburg's] prior rate case proceedings, and already had the historical data necessary to perform such studies." Id. at 192-193. In addition, the Department found that Fitchburg's legal counsel had "in-depth knowledge of the complex structure of the [c]ompany, including its affiliates" and that the same law firm had "performed all of Fitchburg's regulatory work for a significant period of time." Id. at 193.

depreciation, and PBR plan due to the legal counsel and consultants' institutional knowledge and substantial working relationship with the company.[65] D.T.E. 01-56, at 76.

While the Department accepted both Fitchburg's and Berkshire's decisions to forgo the competitive bidding process for some of its outside legal and consulting services, in this case, the Company did not solicit competitive bids for any of its outside services for the rate case. The Company's failure to obtain competitive bids has left the Department with no objective method to determine whether the services could be adequately provided at lower costs (either at lower rates, or by completion of the work in fewer billable hours). Of particular concern is the nearly $1 million the Company's PBR consultant, PEG, charged for the price cap formula. The Company argues that retaining this consultant was appropriate because PEG developed the proprietary database for the Company's price cap formula in its preceding rate case, and, therefore, it was cost-efficient to use the consultant who already had the database (Boston Gas Brief at 122, citing Exh. KEDNE/PJM-1, at 24). However, the updating of the database required considerable expense in itself, and the proprietary nature of the consultant's database

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[65] The Department found that Berkshire "decided to forgo seeking competitive bids due to its law firm's institutional knowledge of [Berkshire] and its operations, and the fact that the same firm has performed all of Berkshire's regulatory work for a significant period of time." D.T.E. 01-56, at 76. The Department noted that Berkshire also did not seek competitive bids for outside consulting services regarding rate design, depreciation, and performance-based rates "because those consultants have had a substantial working relationship with the [c]ompany." The Department found that the company provided adequate justification for its decision not to request bids for those services, because the depreciation expert participated in Berkshire's last six rate cases and thus was intimately familiar with the company's plant and operations; the rate design experts participated in the company's last five rate cases and had extensive knowledge of the company; and the PBR consultant had broad experience in Massachusetts utility regulation. Id.

meant that the Company was in a sense bound to use PEG regardless of the reasonableness of the costs for PEG's work in this proceeding (see Tr. 26, at 3568-3575, 3600-3607).

While Boston Gas asserts its longstanding business relationships with outside consultants as justification for forgoing competitive bidding, Boston Gas has taken this reasoning to the extreme in this case, having not even attempted to obtain competitive bids for any of its outside rate case services (with the arguable exception of the lead-lag study).[66] As Boston Gas itself recognizes, obtaining competitive bids does not mean that the Company must then necessarily retain the services of the lowest bidder (Tr. 14, at 1874). The bidding and qualification process merely provides a benchmark for reasonableness of the cost of the services sought. Moreover, even where the final choice may fall to a consultant with a long-standing relationship to a company and fair-minded observers might regard that choice as sound and warranted, the very discipline of having to submit a competitive bid in a structured and organized process keeps even a consultant with a stellar past performance from taking the relationship for granted. Certainly, no harm is done by competition to provide services, and some gain in efficiency is likely.

The Department has stated that we expect companies to engage in a competitive bidding process for outside rate case services. D.P.U. 96-50 (Phase I) at 79. Here, the Department accepts the Company's justifications for not engaging in a competitive bidding process for its

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[66] The Company stated that it obtained "quotations" from accounting firms as a means of comparing the proposed fee of the consultant who prepared the lead-lag study (Tr. 25, at 3383-3386). No contemporaneous documentation of the quotations appears in the record. This verification process is some means of demonstrating that Boston Gas received a competitive price for this study.

legal and consulting services, based on the experience of the Company's outside attorneys and other consultants. However, in failing to competitively bid any outside services, we further find that Boston Gas has not observed the Department's directives regarding competitive bidding as a means of cost containment in rate cases. Had the Company engaged in the competitive bidding process, it is possible that the total overall rate case expense could have been reduced.

In all frankness, the Department's enforcement of its competitive bidding rule could have been stronger in recent years. Hereafter, however, as means to evaluate each company's efforts to control costs, 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. If 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.

The Department does not seek to substitute its judgment – or that of any intervenor – for the company's in determining which consultant or legal counsel is best suited to serve the company's interests; we do not require the company to engage the services of the lowest bidder regardless of its qualifications. However, the need to contain rate case expense should be accorded a high priority in the review of bids received for rate case work. In seeking recovery of rate case expenses, companies must in the future provide an adequate justification and showing, with contemporaneous documentation, that their choice of outside services is both reasonable and cost-effective. A company that seeks to recover rate case expense when it has

failed to conduct any competitive bidding will be hard-pressed to adequately justify its decision and will put such recovery at risk.

c. Legal Services Discount

Based on his review of invoices, the Attorney General claims that the Company's legal counsel did not actually give Boston Gas an agreed-upon discount for services on the rate case. The Attorney General claims that, because legal invoices from regulatory counsel show that the law firm billed the Company at the same hourly billing rate for rate case work as for other regulatory work, Boston Gas did not actually receive a "discount" on the rate case work.

The legal counsel's billing records do, as the Attorney General states, indicate that the firm charged the Company the same hourly rate for services on the rate case as it does on other matters despite the language of the rate case engagement letter stating that the firm's "time and dollar estimate" for its services for each phase of the rate case was "based on hourly billing rates" that represent a discount from the firm's "current billing rates" (Exh. AG 5-2, at 1). Boston Gas maintains, however, that the law firm representing it in this rate case provides all of the Company's legal services (both rate case-related and non-rate case-related) at the same discount. Also, Boston Gas noted that because the Company had existing working relationships with its legal counsel and consultants, these services commenced at agreed-upon discounted rates well in advance of formal engagement letters (Tr. 14, at 1873-1874).

The Department finds the engagement letter for rate case legal services and the Company's explanation that all legal services provided to Boston Gas are at discounted rates, adequate to support its claim that it received the discount at issue; i.e., a percentage discount

from the law firm's usual "current billing rates" for clients other than Boston Gas (Exh. AG 5-2 [confidential]; Tr. 14, at 1873-1874). Therefore, the Department finds no cause to reduce allowable rate case legal expense to account for an additional "discount" as requested by the Attorney General.

d. "Abandoned" Rate Case

The Attorney General also contends that the Department should disallow $45,350 in legal expense incurred between January and August 2002 for "abandoned" work on a rate case that he claims would have been based on a 2001 test year (Exh. AG 5-6, at 74-88). The Company's legal invoices for rate case work performed from January through June 2002 contain a notation that they are for work "Re: 2001 Rate Case" (id.).[67] The Company argues that the invoices in question were for work for a rate case, initially planned for a 2002 filing, that "carried over" and was used in the Company's ultimate rate case filing made in 2003 (Boston Gas Brief at 122, n.47).

The Department finds insufficient evidence to support the Company's claim that the rate case work begun in early 2002 "carried over" to its May 2003 rate case filing. Rather, the evidence only supports a finding that the Company began work on a rate case for filing in

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[67] The first invoice in the rate case expense filing, for legal services rendered through January 31, 2002, shows that the first date for which the firm billed hours for any kind of rate case work was January 28, 2002 (Exh. AG 5-6, at 74). Each invoice from January through August 2002 contains the notation "Re: 2001 Rate Case." Beginning with the September 2002 invoice, this notation changes to "Re: Rate Case," and this is the notation on all of the subsequent invoices through end of September 2003 (Exhs. AG 5-6, at 74-159; AG 5-6 [supp.] (invoice numbers 16832, 16843)).

2002, but later decided against filing such a case (Tr. 12, at 1541-1542).[68] The legal invoices show a clear demarcation between work for the never-filed 2002 rate case versus the 2003 rate case filing. From January 28, 2002 to June 5, 2002, the law firm billed the Company for work "Re: 2001 Rate Case" totaling $48,697 (Exh. AG 5-6, at 74-88). The firm's billing for rate case work then ceased entirely for nearly four months, resuming on September 30, 2002, with the changed invoice notation "Re: Rate Case" (id. at 89).[69] While it is possible that some work that was performed by the law firm in the early part of 2002 may have been useful in the preparation of this filing, the Company has presented insufficient evidence to support its claim that the legal work performed from January to June 2002 for a rate case with a 2001 test year was either relevant to or useful for the 2003 filing (see Tr. 12, at 1541-1542).[70] The work

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68 The Company stated that it had planned a 2002 rate case filing, and, to the best of the witness' recollection, it would have used a 2001 test year (Boston Gas Brief at 122, n.47; Tr. 12, at 1541-1542). A 2002 filing date would have, in all likelihood, used a calendar 2001 test year, as can be surmised based on the invoice notation "Re: 2001 Rate Case" on invoices from early 2002, as well as Boston Gas' historic practice of using calendar test years, including this proceeding. D.P.U. 93-60, at 1; D.P.U. 90-17/18/55, at 1 (1990); D.P.U. 88-67 (Phase I) at 2; Boston Gas Company, D.P.U. 1100, at 1 (1982);Boston Gas Company, D.P.U. 19470, at 1 (1978); Boston Gas Company, D.P.U. 18264, at 1 (1975).

69 It is also noteworthy that the law firm billed only $1,736 and $3,969 in May and June 2002, a significant drop from the $15,046.20 and $18,175.75 it billed in March and April 2002 (Exh. AG 5-6, at 78-88).

70 The Company explained the reasons why it decided not to file the originally planned rate case with test year 2001, but gave no indication of whether work already performed was useful for later rate case based on 2002 test year (Tr. 12, at 1541-1542). The Company's statement that the work was "carried over" appears for the first time on brief, and is therefore argument, for which the Department finds the record to contain insufficient support.

performed on the aborted 2001-test-year filing amounted to legal services already supported by ordinary rates in force in 2002. It led to no result and cannot be recovered as rate case expense. Therefore, the Department will not permit recovery as a rate case expense of the $48,697 in legal expenses for a separate rate case that the Company considered, but did not file, in 2002.

e. Supporting Invoices

The Department has directed companies to provide all invoices for outside rate case services that detail the number of hours billed, the billing rate, and the specific nature of services performed. D.T.E. 02-24/25, at 193-194; D.T.E. 01-56, at 75; D.T.E. 98-51, at 61; D.P.U. 96-50 (Phase I) at 79. Further, we have stated that failure to provide this information could result in the Department's disallowance of all or a portion of rate case expense. D.T.E. 02-24/25, at 193; D.T.E. 96-50 (Phase I) at 79. In the present case, the Company's invoices were properly itemized for allowable expenses, with a few exceptions discussed below.

In the case of the Company's information technology ("IT") billing systems consultant, the Company included $19,000 in rate case expense for which it did not provide supporting invoices.[71] Without documentation, the Department cannot determine whether these expenses are reasonable. Therefore, this $19,000 in rate case expense is disallowed. Further, a number of the activity reports for IT services state that the consultants were billing the Company while

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[71] The Company did not provide actual invoices or other supporting documentation for the following AEO Management Company invoice numbers: 600 ($6,375), 607 ($5,625), and 613 ($7,000) (Exhs. AG 5-6; AG 5-6 [supp.] (Rate Case Expense Summary at 1)).

"waiting" for information in order to proceed (Exh. AG 5-6; Tr. 24, at 3308-3309).[72] Without further justification, "waiting" for information can not reasonably be considered an activity for which recovery is allowed in rate case expense (see Tr. 24, at 3308-3309; RR-DTE-95). Waiting for information may well be part of the irreducible inefficiency of any complex process, but it is not something ratepayers should have to underwrite. Therefore, the Department finds that the Company has failed to support the reasonableness of the expenses incurred for consultants' waiting time, totaling $21,061, and will not allow recovery of this amount.

Finally, the IT consultants billed the Company a $300 fee for late payment. Much as the Department excludes fines and penalties of all types from cost of service as a matter of public policy, failure of the Company to pay its rate case invoices on time is not something that can reasonably be charged to ratepayers (Exh. AG 5-6, at 37; Tr. 24, at 3309). See, e.g., D.P.U. 88-67 (Phase I) at 142-143; Kings Grant Water Company, D.P.U. 87-228, at 18-19 (1988). For these reasons, the Department disallows a total of $40,361 in IT consultant fees as insufficiently supported or justified by Boston Gas.

The Department further disallows a portion of rate case expense for the Company's PBR consultant, PEG, which billed the Company monthly from March 2002 through May 2003 (Exhs. AG 5-6, at 164-180; AG 5-6 [supp.]). First, each of the invoices submitted

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[72] Specifically, the following AEO Management Company invoices and associated status reports include time billed for "waiting": invoice numbers 614 ($5,125), 615 ($2,250), 619 ($3,217), 620 ($2,500), 622 ($2,500), 623 ($2,500), and 624 ($2,969), for a total of $21,061 (Exh. AG 5-6, at 49-51, 60-63, 66-71).

to support PEG's services included separate charges for "media" and "communication" totaling $1,545 (Exhs. AG 5-6, at 164-180; AG 5-6 [supp.]).[73] The Company explained that these charges were for mail, telephone, fax, and online research, some of which were not specific to PEG's work on the rate case, but rather were equally allocated to all of PEG's clients (RR-DTE-118; RR-DTE-125; Tr. 25, at 3469; Tr. 26, at 3600-3602). The Department has previously disallowed similar "miscellaneous office expenses." See, e.g., D.T.E. 02-24/25, at 194 (company denied recovery of adder for telephone, reproduction, postage and data processing because there was no itemization or means to determine if the expenses were reasonable).

In addition, the Company failed to provide sufficient detail regarding the specific nature of services performed in connection with some of the PEG invoices. A number of the time sheets submitted as documentation for PEG's charges show hours billed only, without a description of the services performed by the consultant (RR-AG-90-A at 13-16, 26, 27, 29, 41, 48, 74, 75, 85, 86, 118).[74] In addition, the Company did not provide descriptions of services

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[73] The media or communication expense appears on every PEG invoice (Exhs. AG 5-6, at 164-180; AG 5-6 [supp.])

[74] The Company submitted PEG invoices containing a total of hours worked on the rate case by each individual billing Boston Gas for rate case work (Exhs. AG 5-6, at 164-180; AG 5-6 [supp.] (August 2003 and September 2003 PEG invoices)). The Company was asked to provide "internal time cards maintained by PEG by individual person on a daily basis" showing detail of what, specifically, the individuals at PEG were doing for the hours reported (RR-AG-90-A; see Tr. 26, at 3606-3607). In response, the Company submitted 155 pages of individual time sheets, providing an hourly breakdown with description of activity, as backup documentation for the invoices. However, the "description" of activity performed is blank on 14 of those

(continued…)

performed in conjunction with PEG's August and September 2003 invoices (Exh. AG 5-6 [supp.]; RR-AG-90-A). The total billed for hours for which there is no activity description is $112,305.[75] Because the Company failed to properly itemize these expenses, the Department has no way to determine whether these expenses are reasonable. Therefore, the Department disallows rate case expenses associated with hourly billings for the Company's PBR plan, totaling $113,850, as insufficiently supported or justified.

f. Miscellaneous Expenses

The Company requests recovery of numerous miscellaneous expenses. The Department disallows a number of these items totaling $6,184 as follows. First, the Company's expenditures include $4,652 for computer supplies ($2,387 in software and $2,265 in hardware) (Exh. AG 5-6, at 217-220; Tr. 25, at 3477-3478). These are items that the Company presumably will have use of beyond completion of the present rate case, and, therefore, should not be recovered as a rate case expense.

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74 (…continued)
time records (RR-AG-90-A at 13-16, 26, 27, 29, 41, 48, 74, 75, 85, 86, 118). The "time cards" appear to be standardized forms with a curious consistency across personnel and months, suggesting that they were documents created on an after-the-fact basis. See Wylde Wood Water Works Company, D.P.U. 86-93, at 16 (1987).

75 This is the total obtained by multiplying the number of hours for which the consultants billed without an activity description (RR-AG-90-A at 13-16, 26, 27, 29, 41, 48, 74, 75, 85, 86, 118) by the consultant's confidential hourly billing rate, found on the PEG invoices (Exhs. AG 5-6, at 164-180 [confidential]), plus the total of the August 2003 and September 2003 invoices, for which no activity description was submitted (Exh. AG 5-6 [supp.]).

The Department also disallows $1,532 in food and other miscellaneous expenses of Company employees (Exh. AG 5-6, at 237-250, 259-271; Tr. 25, at 3464-3467). The Company may choose to reimburse its employees for personal expenses incurred during a rate case, but the mere fact that such expenses are incurred does not make it reasonable for the Company to recover the items via rate case expense. Companies must aggressively seek to contain costs associated with rate cases. Reimbursement of employees for miscellaneous items such as meals and parking based on receipts permits no consideration by the Department of whether the expenses are reasonable and, therefore, recovery of these as rate case expense cannot be allowed.

Finally, the Attorney General also seeks elimination from the local distribution adjustment clause ("LDAC") of legal fees for work related to environmental remediation by the firm Dickstein Shapiro on the grounds that the work was awarded to what he terms a Company insider. These legal fees are not part of the Company's rate case expense but are for other legal services provided during the test year (Tr. 14, at 1881). The LDAC-related legal fees are recovered via the LDAF and not in base rates. The Attorney General has raised this issue in the wrong context, as the recovery of these fees is appropriately addressed in the Company's next LDAC filing.

g. Fixed Legal Cost for Compliance Phase

The Department's longstanding precedent allows only known and measurable changes to test-year expenses to be included as adjustments to cost of service. D.T.E. 02-24/25, at 195; D.T.E. 98-51, at 62. Proposed adjustments based on projections or estimates are not

known and measurable, and recovery of those expenses is not allowed. D.T.E. 02-24/25, at 196; D.T.E. 01-56, at 75. Recently, the Department stated that we would not preclude the recovery of fixed fees for completion of compliance filing work in a rate case, but the reasonableness of the fixed fees must be supported by sufficient evidence. D.T.E. 02-24/25, at 196. Given an adequate showing of the reasonableness of fixed contracts to complete a case after the record closes and briefs are filed, the Department stated that a company may qualify to recover such expenses.[76] We have stated that documented and itemized proof, however, is a prerequisite to recovery. Id..

Boston Gas proposes to recover a fixed fee for legal services for completion of the compliance phase of this proceeding (Exhs. AG 5-2 [confidential]; AG 5-6 [supp.] [confidential] (Rate Case Expense Summary at 1)). However, the Company has presented no evidence to support the reasonableness of the fixed fee, such as the number of hours estimated to complete the compliance filing or the other factors which the parties considered when arriving at the negotiated fee (see Tr. 25, at 3487).

In D.T.E. 02-24/25, at 196, the Department denied a nearly identical request by Fitchburg to recover a fixed fee for services necessary to complete the compliance phase of its last rate case proceeding because the company did not present any evidence to support the

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[76] The Department stated that the basis of this shift in practice is threefold. First, completing the case through the compliance filing is an inescapable regulatory requirement. Second, the cost of meeting that requirement is not negligible and may, in fact, be substantial. Finally, it is not fair to levy a requirement and deny recovery of properly documented and reasonable costs incurred to satisfy that requirement. D.T.E. 02-24/25, at 196.

reasonableness of its negotiated costs; and the Department stated unequivocally that recovery of expense for completion of a rate case will not be permitted without documented and itemized proof that the fixed fee is reasonable. Likewise, in D.T.E. 01-56, the Department disallowed the estimated fee for preparation of the compliance filing as "not known and measurable." D.T.E. 01-56, at 75. Although the fee does not look unreasonable on its face, we require something more than the fixed contract itself to judge whether the contract terms (e.g., hours billed, hourly fee, not to exceed total, etc.) are reasonable. Recovery is not automatic, but requires some explanation of its basis. As Boston Gas has not shown that its fixed fee for legal costs in the compliance phase of this proceeding is reasonable, the Department denies recovery of the expense as insufficiently supported or justified. Nonetheless, the rule on recovery stated in D.T.E. 02-24/25 remains in effect. We just need more than we have here for it to be properly invoked.

h. Normalization Period

The proper method to calculate a rate case expense adjustment is to determine the rate case expense, normalize that expense over an appropriate period, and then compare it to the test year level to determine the adjustment. D.T.E. 02-24/25, at 197; D.T.E. 98-51, at 62; D.P.U. 95-40, at 58. The Department's practice is to normalize rate case expenses so that a representative annual amount is included in the cost of service. D.T.E. 02-24/25, at 191; D.T.E. 01-56, at 77; D.T.E. 98-51, at 54; D.P.U. 96-50 (Phase I) at 77; Berkshire Gas Company, D.P.U. 1490, at 33-34 (1983). Normalization is not intended to ensure dollar-for-dollar recovery of a particular expense; rather, it is intended to include a representative annual

level of rate case expense. D.T.E. 02-24/25, at 191; D.T.E. 01-56, at 77; D.P.U. 96-50 (Phase I), at 77; D.P.U. 91-106/138, at 20.

In the case where a company is proposing a PBR plan, the Department will also look at the term of the PBR plan.[77] If the term of a PBR plan exceeds the average frequency between a company's most recent rate proceedings as determined above, the Department uses the term of the PBR plan as the normalization period for rate case expense. D.T.E. 01-56, at 77; D.P.U. 96-50 (Phase I) at 78-79.

Boston Gas proposed to normalize its rate case expense over the term of its proposed five-year PBR plan (Exh. KEDNE/PJM-1, at 23-24). As discussed in Section VIII.C.3, below, the approved term of the Company's PBR plan is ten years. This term exceeds the four-year frequency between Boston Gas' most recent rate proceedings as determined above, and, therefore, it is an appropriate normalization period for rate case expense. This results in an annual rate case expense amount of $182,633.[78]

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[77] Where there is no PBR plan, the Department determines the appropriate period for recovery of rate case expenses by taking the average of the intervals between the filing dates of a company's last four rate cases (including the present case), rounded to the nearest whole number. D.T.E. 02-24/25, at 191; D.P.U. 91-106/138, at 19-20; D.P.U. 1490, at 33-34. Application of this precedent results in a normalization period of four years as follows: Boston Gas' last four rate cases were D.P.U. 90-55 (filed March 16 1990), D.P.U. 93-60 (filed April 16, 1993), D.P.U. 96-50 (filed May 17, 1996), and D.T.E. 03-40 (filed April 16, 2003). The differences between these cases (3.08 years plus 3.08 years plus 6.83 years), divided by three and rounded to the nearest whole number, results in a normalization period of four years.

[78] The annual expense amount is the total approved rate case expense, $1,826,331, divided by the approved PBR period of ten years.

i. Conclusion

The Company has requested recovery of rate case expense of $2,035,423, not including fixed legal fees to complete the compliance phase of the proceeding (Exh. AG 5-6 [supp.]). Of this amount, the Department disallows $209,092,[79] as set forth above, and approves a rate case expense of $1,826,331. This amount is $161,042 higher than the Company's original rate case expense estimate of $1,665,289.

Based on the findings above, the Department concludes that the correct level of normalized rate case expense is $182,633 ($1,826,331 divided by ten years). Because Boston Gas has proposed a normalized rate case expense of $333,058, the Company's proposed cost of service will be reduced by $150,425.

K. Meter Inspection Fees

1. Introduction

The Secretary of Administration and Finance for the Commonwealth of Massachusetts had established certain increased state fees pursuant to 801 C.M.R. § 4.02:220, to take effect July 1, 2003 (Tr. 12, at 1445, 1452; RR-AG-48). Among these increased fees is the state meter inspection fee, with the previous fees of $5 for residential meters and $20 for C&I meters increasing to $10 and $40, respectively (Exh. KEDNE/PJM-2 [rev. 2] at New; Tr. 12, at 1445). As a result of this increase, the Company proposes an adjustment to incorporate the

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[79] We do not include the fixed fee for completion of the compliance phase in the total rate case expense or in the amount of rate case expense disallowed, as the fixed fee is confidential (Exhs. AG 5-2 [confidential]; AG 5-6 [supp.] [confidential]). As stated above in Section IV.J.3.g, the fixed fee is disallowed.

new meter inspection fees into cost of service (Tr. 12, at 1445). Based on the number and type of meters inspected during the test year, the Company proposes an increase to test year inspection fees of $483,215 (Exh. KEDNE/PJM-2 [rev. 2] at New).

Boston Gas contends that the increase in state meter inspection fees will have a significant effect on the Company's expenses (Tr. 12, at 1445). The Company represents that its proposed meter inspection fee adjustment is known and measurable (Exh. KEDNE/PJM-2 [rev. 2] at New). No other party commented on this issue.

2. Analysis and Findings

The increase in meter testing fees took effect on July 1, 2003, and therefore, constitutes, a known and measurable change to test year cost of service. Berkshire Gas Company, D.P.U. 90-121, at 120 (1990). The Department finds that the Company has properly applied the increase to the number and types of meters inspected during the test year. Accordingly, Department will increase the Company's test year cost of service by $483,215.

L. Property Leases

1. Introduction

During the test year, Boston Gas booked $2,131,861 in property lease expense (Exh. KEDNE/PJM-2 [rev. 2] at 14). During that period, Boston Gas terminated its leases at One Beacon Street in Boston ("Beacon Street"), Morse Street in Norwood, and Dorchester Avenue, and relocated its employees from these locations to its consolidated offices at 51 Second Avenue, Waltham ("Waltham") (Exh. KEDNE/PJM-2, at 17; Tr. 1, at 9-10; Tr. 8, at 910-911).

Boston Gas proposes to increase its test year lease expense by $1,814,187 to account for (1) the Company's new office lease in Waltham, (2) the termination of leases for the Company's former Beacon Street, Norwood, and Dorchester properties, (3) an annualized increase in lease expenses associated with the liquified natural gas ("LNG") tanks in Lynn and Salem, which became effective July 1, 2002, and (4) $801,429 in net operating expenses associated with the Waltham property (Exhs. KEDNE/PJM-1, at 17; KEDNE/PJM-2 [rev. 2] at 14; Tr. 1, at 9-10). Therefore, the Company reduced test year lease expense for the Beacon Street, Norwood, and Dorchester facilities by $502,565, $222,248, and $28,504 respectively, and increased test year expense to incorporate Boston Gas' allocated portion of the annualized expense for the Waltham facility, or $1,560,619 (Exh. KEDNE/PJM-2 [rev. 2] at 14). Therefore, Boston Gas' proposes a total increase in test year cost of service of $1,814,187 for property lease adjustments (id.).

Boston Gas' Waltham facilities are subject to a lease for a term of 20 years, effective November 15, 2002 (Exh. DTE 2-3). Keyspan Services is the lessee (id.). Under the terms of the lease, Keyspan Services leases 113,532 square feet at an annual fixed rent that begins at $17 per square foot for the second year of the lease, and escalates annually to $30.50 per square foot during the last year of the lease term (id. at 2-3).[80] The lease also requires Keyspan Services to pay associated taxes and operating expenses for the facility (Exh. DTE 2-3 [rev. 2] at 2). Because the Waltham facility is used by all of Keyspan's New England

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[80] The Company has an option to lease an additional 14,000 square feet at the Waltham property, the cost of which is not included in this filing (Tr. 2, at 162-163).

affiliates as well as some employees assigned to Keyspan's New York affiliates, 65.83 percent of the total lease and operating expense was allocated to Boston Gas, based on the allocation percentages previously used for the Beacon Street and Norwood properties (Exhs. KEDNE/PJM-1, at 17; KEDNE/PJM-2 [supp.] at 70; Tr. 2, at 180-182). Based on this 65.83 percent allocation, the Company proposes a lease expense of $1,560,619 and an operating expenses of $801,429 for the Waltham facility (Exh. KEDNE/PJM-2 [rev. 2] at 14).

2. Positions of the Parties

a. Attorney General

The Attorney General contends that the Company has more than tripled its lease expenses by consolidating operations in Waltham (Attorney General Brief at 48-49; Attorney General Reply Brief at 36). The Attorney General argues that, despite this increase, Boston Gas has not demonstrated any net benefits to ratepayers as a result of the Company's consolidation of operations in Waltham (Attorney General Brief at 43; Attorney General Reply Brief at 36-38). According to the Attorney General, Company employees remain in diverse locations, property insurance has increased, and litigation is underway with the previous Waltham tenant (Attorney General Brief at 49). Further, the Attorney General contends that the Company has not presented any evidence in the form of either data or analysis demonstrating that savings exceed increases in lease expense (id.; Attorney General Reply Brief at 36-37).

The Attorney General maintains that Boston Gas' per square footage analysis of savings is flawed because (1) the Waltham lease is for more space than at the Company's former

facilities, (2) it does not recognize sublease revenues as a credit to ratepayers,[81] and (3) it inappropriately assigns a zero value to the first year's lease expense (Attorney General Reply Brief at 37, citing Exhs. DTE 2-3 (November 15, 2002); DTE 2-2(c), (d); KEDNE/PJM-2 [rev. 2] at 14; RR-AG-8). Therefore, the Attorney General proposes that the Department remove $1,637,000 in incremental lease expense associated with the Waltham office space, representing the difference between the total lease associated operating expenses for the Waltham facility of $2,362,000 and $725,000 in test year lease expense for the Beacon Street and Norwood facilities (Attorney General Brief at 48-49, n.33).

b. Boston Gas

Boston Gas argues that its test year adjustments for property leases are necessary in order to annualize the effect of cost changes that occurred during the test year and to recognize the changes in specific properties used by the Company (Boston Gas Brief at 80). Responding to the Attorney General's argument that the Company has not proved that net benefits to ratepayers resulted from consolidating operations in Waltham, Boston Gas contends that, although it has an obligation to contain costs, Department precedent does not require utilities to perform a cost-benefit analysis when executing office leases (id. at 81). Further, Boston Gas argues that the Attorney General has not identified any precedent or standard to support his claim that the lease expense should be removed from the cost of service (id.). Boston Gas states that because office space in the city of Boston had become expensive, the Company

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[81] According to the Attorney General, 2,029 square feet at Waltham is being sublet to a non-regulated, unaffiliated entity (Attorney General Reply Brief at 37, n.29, citing Exhs. DTE 2-2(c), (d); DTE 2-3).

reduced its office space at Beacon Street in 1997, from 90,000 square feet to 30,000 square feet (id. at 82, citing Exh. AG 4-28).

In support of its proposed Waltham lease expense, the Company compared the $17 per square foot cost associated with the Waltham lease with the cost of $57 to $59 per square foot associated with Beacon Street and the cost of approximately $14 per square foot for Norwood (id. at 81-82, citing Exhs. DTE 2-4, at 2; DTE 2-4(c); AG 4-28, at 2-3). Based on this comparison, Boston Gas concluded that the Waltham lease is demonstrably less expensive than the previous Boston and Norwood leases (id. at 81). The Company disputes the Attorney General's claim that the Company's per-square foot analysis is "misleading and inappropriate" (Boston Gas Reply Brief at 81-82, citing Exh. DTE 2-2; Tr. 2, at 157, 161-162; Tr. 8, at 910). The Company explains that it occupies the 113,000 square feet of space that is included in the cost of service and that leasing the Waltham space has enabled the Company to consolidate employees in one location resulting in greater efficiencies (id. at 81, citing Exh. DTE 2-2; Tr. 2, at 157, 161-162; Tr. 8, at 910). In fact, the Company argues that on a cost per square footage basis, its Waltham expenses are less than those under the Beacon Street and Norwood leases (Boston Gas Brief at 81, citing Exhs. DTE 2-2; DTE2-4).[82] The Company also disputes the Attorney General's position that the Waltham lease expense does not recognize sublease revenues as a credit to ratepayers, arguing that the Company has no burden

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[82] Specifically, the Company contrasts the Waltham lease expense of $0 for lease year one, and the $17 per square foot in lease expense in year two, with the test year lease expense of $14 per square foot for 20,000 square feet at Norwood, and $57 to $59 per square foot for 13,000 square feet at Beacon Street (Boston Gas Brief at 81-82, citing Exhs. DTE 2-4; AG 4-28).

to show that every square foot of the Waltham space will be dedicated for Company purposes, as long as the Company has adjusted the costs included in the cost of service accordingly (Boston Gas Reply Brief at 81, citing Exhs. KEDNE/PJM-2 [supp.] at 68-74; DTE 2-2). The Company also contends that the Attorney General's assertion that the Company inappropriately assigns a zero value to the first year's lease expense is inaccurate and disregards accepted accounting principles (id. at 82). Rather, Boston Gas argues that the Company negotiated free rent for year one, and that the benefit from this was amortized over the 20-year term of the lease, which reduces the lease expense for the subsequent 19 years (id., citing Exh. DTE 2-2; Tr. 2, at 157, 161-162; Tr. 8 at 910).

3. Analysis and Findings

A company's lease expense represents an allowable cost qualified for inclusion in its overall cost of service. Nantucket Electric Company, D.P.U. 88-161/168, at 123-125 (1988). Increases in rental expense based on executed lease agreements with unaffiliated landlords are recognized in cost of service, as are operating costs (maintenance, property taxes, etc.) that the lessee agrees to cover as part of the agreement. D.P.U. 95-118, at 42, n.24; D.P.U. 88-67 (Phase I) at 95-97. The Department has also found that the standard for inclusion of lease expense is one of reasonableness. D.P.U. 89-114/90-331/91-80 (Phase One) at 96.

The evidence demonstrates that Boston Gas entered into a written lease agreement for its offices located in Waltham (Exh. DTE 2-4). Thus, the Department finds that the lease is eligible for inclusion in Boston Gas' overall cost of service. D.P.U. 88-161/168, at 123-125. However, the Department also must examine the overall reasonableness of the Waltham lease.

The evidence indicates that Boston Gas' consolidation to its Waltham office space has reduced redundant office space, while obtaining larger office space at a lower cost per square footage (i.e., $17 per square foot for approximately 113,000 square feet versus $57 to $59 per square foot for Beacon Street) (Exhs. DTE 2-3, at 2; DTE 2-4(c); AG 4-28). The Department is also persuaded that the elimination of the Company's Beacon Street and Norwood offices in favor of greater centralization in Waltham will allow Boston Gas to realize efficiencies to its non-field operations through improved communications, thereby improving customer service (see Tr. 8, at 911-912). Thus, the Department finds that the Company's lease expense for its Waltham facility is reasonable and appropriately included in cost of service.[83]

Although the Company notes that there is no Department precedent requiring a cost-benefit analysis for executing leases, prudent business practice would require a pre-execution analysis to determine whether it is cheaper to purchase or lease office space, in order to obtain the least expensive office space for a company's ratepayers. D.P.U. 89-114/90-331/91-80, Phase I, at 96, 98. Therefore, Boston Gas is directed to conduct a cost-benefit analysis of the Company's rental properties versus purchasing comparable space as part of the Company's next base rate filing.

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[83] Concerning the Attorney General's argument that the ongoing litigation with the previous tenant is further evidence of the lack of benefits to ratepayers from the Waltham lease, the litigation concerns a dispute between Keyspan and Renaissance Worldwide, another tenant at Waltham, over signage rights at the Waltham facility (Exh. AG 21-19). The Department does not consider this litigation to have any significant relevance regarding Boston Gas' decision to enter to enter into the lease.

The Company subleases 2,029 square feet of its total space of 113,532 square feet to Energy Credit Union, an unaffiliated company that serves as a credit union for Keyspan employees (Exh. DTE 2-2; Tr. 2, at 163). Because this portion of the leased property at Waltham is not related to utility purposes, the Department finds that an adjustment to cost of service is appropriate to prevent double-recovery of this pro rata share of lease and operating costs from ratepayers. See D.P.U. 95-118, at 139; D.P.U. 92-210, at 11-12. Therefore, the Department will reduce the Waltham lease and operating expense by 1.79 percent, representing the percentage of square footage occupied by Energy Credit Union in Waltham. This results in a reduction to lease expense of $27,935 and a reduction to operating expense of $14,346. Accordingly, the Department will reduce the Company's proposed cost of service for the Waltham lease by a total of $42,281.

Regarding Boston Gas' other proposed adjustments to test year lease expense, the Company's leases for Norwood and Dorchester have been terminated (Exhs. KEDNE/PJM-1, at 17; DTE 2-4; Tr. 1, at 9-10). Additionally, the Company has moved out of Beacon Street and excluded the associated lease expense from cost of service (Exh. KEDNE/PJM-1, at 17; Tr. 2, at 166-167). Therefore, the proposed lease expense reductions for these properties constitute a known and measurable change to test year cost of service. D.P.U. 87-260, at 75. Accordingly, the Department will reduce the Company's test year cost of service by a total of $753,317. Moreover, the annualization of test year lease expense associated with the Company's Lynn and Salem LNG tanks took effect on July 1, 2002, in accordance with

executed lease agreements (Exhs. KEDNE/PJM-1, at 17; KEDNE/PJM-2 [supp.] at 69). Therefore, the Department will increase the Company's test year cost of service by $205,456 for these leases. D.P.U. 95-118, at 42, n.24; D.P.U. 88-67, Phase I, at 95-97.

Based on the foregoing analysis, the Department has removed $42,281 associated with the subleased space at Waltham from the Company's proposed cost of service. This results in a pro forma lease expense of $3,072,338. Accordingly, the Company's proposed cost of service will be reduced by $42,281.

M. Postage Expense

1. Introduction

During the test year, Boston Gas booked $2,423,592 in postage expense (Exh. KEDNE/PJM-2 [rev. 2] at 16). The Company proposes an increase of $124,491 to annualize the 10.83 percent increase in postal rates that became effective on July 1, 2002, thereby producing a proposed postage expense of $2,548,084 (Exhs. KEDNE/PJM-1, at 18; KEDNE/PJM-2 [rev. 2] at 16). The Company argues that its proposed postage expense adjustment annualizes the postage rate increase that took effect on July 1, 2002 (Boston Gas Brief at 58). No other party commented on this issue.

2. Analysis and Findings

Postage expense is a legitimate cost of doing business. If a postage increase occurs prior to the issue of an Order, the increase is eligible for inclusion in cost of service as a known and measurable change to test year expense. D.P.U. 88-172, at 23-24; Massachusetts Electric Company, D.P.U. 800, at 29-30 (1982). The increase in postal expense is a known

and measurable change from test year cost of service (Exhs. KEDNE/PJM-1, at 18; KEDNE/PJM-2 [rev. 2] at 16). Accordingly, the Department will increase the Company's test year cost of service by $124,491.

N. Shareholder Services

1. Introduction

During the test year, Keyspan incurred $541,997 in expenses associated with shareholder services and its dividend reinvestment plan (Exh. AG 1-76). Of this amount, 21 percent, or $113,819, was allocated to Boston Gas (id.; Tr. 23, at 3146). Boston Gas states that it is not seeking recovery of this expense in cost of service (Tr. 23, at 3146).

2. Positions of the Parties

a. Attorney General

The Attorney General argues that the Department has consistently excluded shareholder expenses from cost of service (Attorney General Brief at 72-73, citing NYNEX Price Cap, D.P.U. 94-50, at 326-327 (1995); D.P.U. 92-210, at 52; Western Massachusetts Electric Company, D.P.U. 88-250, at 47 (1989). The Attorney General maintains that the Company has failed to provide any reason for a departure from this precedent, and, therefore, proposes that the Department exclude the approximately $114,000 in shareholder services expense from Boston Gas' cost of service (id. at 73, citing Exh. AG 1-76).

b. Boston Gas

Boston Gas maintains that it has already removed its expenses related to shareholder services from test year cost of service (Boston Gas Brief at 119, citing Tr. 23, at 3145). Therefore, the Company considers the Attorney General's point on this issue to be moot (id.).

3. Analysis and Findings

The Department's policy has been to exclude shareholder-related expenses from cost of service. D.P.U. 94-50, at 326-327; D.P.U. 92-210, at 52; D.P.U. 88-250, at 47. As a result of the SEC audit, the SEC determined that shareholder-related services associated with corporate reporting should be assigned in their entirety to Keyspan, rather than being allocated among Keyspan's affiliates (Tr. 23, at 3146). The $541,997 in expenses associated with shareholder services and the dividend reinvestment plan are part of the Keyspan Services-related expenses that Boston Gas removed from cost of service (Exhs. KEDNE/PJM-2 [rev. 2] at 26; KEDNE/PJM-12; Tr. 23, at 3146-3147). Accordingly, the Department finds that no further adjustment for shareholder-related expenses is required.

O. Strike Contingency Expense

1. Introduction

During the test year, Boston Gas was engaged in contract negotiations with its largest union, Local 12003 (Exhs. KEDNE/PJM-1, at 19; AG 1-42(a)). In order to ensure that operations would continue in the event of a work stoppage, the Company incurred incremental strike contingency expenses of $321,865 (Exhs. KEDNE/PJM-1, at 19; KEDNE/PJM-2 [rev. 2] at 17). These expenses included the following: (1) the hiring of outside contractors to

train non-union staff on the use of critical equipment necessary to ensure the continuation of safe operations; (2) initiation of a customer communication program; and (3) implementation of security measures (e.g., changing locks to secure company assets, fencing installation, communications equipment and hiring security personnel) (Exh. KEDNE/PJM-1, at 19). Boston Gas proposes to normalize the strike contingency expense $321,865 over a period of four years, which is equal to the term of the collective bargaining agreement (id.). Therefore, the Company proposes to increase its test year cost of service by $80,466 (Exh. KEDNE/PJM-2 [rev. 2] at 17).

Boston Gas maintains that the Department has recognized that preparation for potential labor strikes is essential in order to maintain service in event of a strike (Boston Gas Brief at 58, citing D.T.E. 01-56, at 65. The Company argues that its efforts to protect nonunion employees and assets was an integral part of its strategy to both minimize labor costs in event of a strike and prevent disruption of service to ratepayers (id. at 59). No other parties commented on this issue.

2. Analysis and Findings

The Department has found that preparation for a potential labor strike is essential to ensure that a company continues to operate in the event of a strike. D.T.E. 01-56, at 65-66. Moreover, the Company will need to update or develop new strike contingency plans each time it negotiates a labor contract. Therefore, the Department finds those strike contingency expenses to be recurring. Id. As the Company's strike contingency expenses are recurring, the Department will allow their inclusion in the Company's cost of service.

Concerning the period of time that the Company should normalize these expenses, the Department in the past has found it appropriate to normalize these expenses over the life of the collective bargaining agreement. Id. The Company's contracts with locals 12003 and 12012-04 of the United Steelworkers of America have a term of four years (Exhs. KEDNE/JCO-2; AG 1-42(a); AG 1-42(c)). Therefore, the Department will normalize the Company's strike contingency expense over four years. Accordingly, the Department will increase the Company's test year cost of service by $80,466.

P. Sale of Utility Property

1. Introduction

Until 1998, Boston Gas owned a 7.6-acre parcel of land and a building on Main Street in Concord, Massachusetts (Exhs. KEDNE/PJM-1, at 17; KEDNE/PJM-2 [supp.] at 76). The building and equipment in Concord housed utility operations and the land surrounding the building was held by the Company for future use (Exh. KEDNE/PJM-1, at 17-18; Tr. 17, at 2236).

In 1998, the Company sold the Concord property for gross proceeds of $1,436,570 (Exh. KEDNE/PJM-1, at 18). The Company computed the gain on the sale allocated to utility property by first reducing the sales proceeds of $1,436,570 by the net book value of the building and equipment of $156,870, resulting in net proceeds of $1,279,700 (Exh. KEDNE/PJM-2 [rev. 2] at 15). Next, the Company allocated the net proceeds to utility operations based on the ratio of square footage used as utility property to the total square footage, including property held for future use (Exhs. KEDNE/PJM-1, at 18; KEDNE/PJM-2

[supp.] at 75). Based on a 16.6 percent allocation to utility operations, Boston Gas determined that the net gain allocable to utility plant was $212,430 (Exh. KEDNE/PJM-2 [rev. 2] at 15). Finally, the Company reduced the $212,430 net gain by the book value of the land underlying the facility of $9,950, producing a net gain allocated to utility operations of $202,480 (Exh. KEDNE/PJM-1, at 18).

Boston Gas proposes to amortize the $202,480 gain over the five-year period of the PBR plan in order to return the gain on utility property to customers (id.). This adjustment results in a proposed decrease to the test year cost of service of $40,496 (id.; Exh. KEDNE/PJM-2 [rev. 2] at 15).

2. Position of the Parties

a. Attorney General

The Attorney General argues that the Company has violated, in two respects, the Department's long-standing policy on gains of sale of utility property by not recognizing the entire gain on the sale of the Concord property (Attorney General Brief at 60). First, the Attorney General objects to Boston Gas' starting point for its calculation of the gain, because the Company began with claimed sales proceeds of $1,436,570, rather than what he contends was the actual purchase price of $1,500,000 (id.). Moreover, according to the Attorney General, the Company could not explain the $63,430 difference between two sales price figures provided (id. at 61, citing Tr. 17, at 2235).

Second, the Attorney General maintains that the Company understated the entire gain by applying the 16.6 percent utility/non utility allocation before subtracting the book value of

the land (id., citing Exh. KEDNE/PJM-2 [rev. 2] at 15). As support for his argument, the Attorney General notes that the Company admitted that calculating the gain on the sale after subtracting the book value of the land would have been a more accurate method (id., citing Tr. 24, at 3328). The Attorney General concludes that the Department should incorporate these two adjustments to recognize an additional amortized gain on the sale of the Concord property of $3,766 (id.).

b. Boston Gas

Boston Gas contends that the appropriate net gain associated with the Concord property is $202,480 (Boston Gas Brief at 104-105, citing Exh. KEDNE/PJM-2, at 15). The Company argues that its proposal to amortize the gain of the sale of the Concord property over the five-year period of the PBR plan is consistent with Department precedent regarding the gain on sales of utility property and, therefore, should be approved (id. at 105).

3. Analysis and Findings

The Department's long-standing policy with respect to gains on the sale of utility property has been to require the return to ratepayers of the entire gain associated with the sale. Commonwealth Electric Company, D.P.U. 88-135/151, at 92 (1988); D.P.U. 88-250, at 35-41; Boston Gas Company, D.P.U. 1100, at 62-65 (1982). In the case of property sold prior to the test year used in a rate proceeding, the Department has found that the ratemaking treatment of gains or losses associated with a property transfer are not dependent upon the timing of the transfer relative to the test year. D.P.U. 95-118, at 143; Assabet Water Company, D.P.U. 95-92, at 30 (1996); D.P.U. 88-135/151, at 92.

The starting point for calculating the gain on the sale of property is generally the purchase price, unless sales expenses are incurred, in which case the purchase price is reduced by sales expenses in computing the amount realized from the sale. D.P.U. 95-118, at 142. The purchase and sales agreement for the Concord property specifies a sales price of $1,500,000 (Exh. AG 6-41, at 4). The Company was unable to explain the $63,430 difference between the $1,500,000 purchase price and the $1,436,570 proceeds it used as a starting point for calculating the gain on the Concord property (Tr. 17, at 2235). Accordingly, we find that the contract price of $1,500,000 is the appropriate basis for calculating the gain.

Similarly, the sale of the Concord property involved the transfer of land being used for nonutility purposes with buildings and the land on which they were located being used for utility purposes (Tr. 24, at 2236). Because a portion of the land is associated with the buildings, the Company acknowledged, and we agree, that it is more accurate to first calculate the total gain on the sale and then allocate that gain to utility property, rather than to allocate the gain on the sale of the buildings separately to utility plant before subtracting the entire book value of the land (id. at 3328). Therefore, the Department finds that Boston Gas has incorrectly calculated the appropriate gain on the sale of the Concord property. Using the appropriate method, the Department finds that the gain on the sale of the Concord property is $222,960.[84]

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[84] The Department has recalculated the gain on the sale of the Concord property by first subtracting the $156,870 book value of the building and equipment from the purchase price of $1,500,000, resulting in net proceeds of $1,343,130 (Exh. KEDNE/PJM-2 [rev. 2] at 15). Next, the Department has applied the 16.6 percent allocation factor to

(continued…)

Concerning the Company's proposed amortization period, the Department has found that an appropriate term for Boston Gas' PBR plan is ten years. Section VIII.C.3, below. Thus, using a five-year amortization here would result in an excessive gain being passed back to ratepayers over the term of the Company's PBR plan. D.T.E. 01-56, at 36. Therefore, the Department finds that an appropriate amortization period is ten years, with an annual amortization expense of $22,296. The Company had proposed an amortization expense of $40,496 (Exh. KEDNE/PJM-2 [rev. 2] at 15). Accordingly, the Company's proposed cost of service will be increased by $18,200.

Q. Property and Liability Insurance

1. Introduction

Boston Gas carries a variety of insurance coverages, including general liability, excess liability, excess director and officer liability, property, and blanket crime coverage (Exh. KEDNE/PJM-2 [rev. 3], at 13). During the test year, the Company incurred insurance expenses of $1,518,493 (id.). Boston Gas proposes to increase its test-year insurance expense to account for known and measurable changes resulting from the renewal and annualization of premium costs, as well as the incorporation of its test year travel accident and terrorism insurance coverage into other policies (id. at 16; KEDNE/PJM-2 [rev. 3] at 13; Tr. 2, at 198-199). Therefore, the Company has increased its test year insurance expense by $607,287 to recognize the latest insurance premiums for 2002 through 2003, bringing the

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[84] (…continued)
utility operations to the net proceeds, resulting in a net gain of $222,960 (see Exh. KEDNE/PJM-2 [supp.] at 75).

Company's total proposed insurance expense up to $2,125,780 (Exh. KEDNE/PJM-2 [rev. 3] at 13).

The Company's insurance costs are initially charged to Keyspan Services and allocated to Boston Gas based on individual allocation factors that vary by policy type and are designed to be consistent with the nature of the insurance cost being allocated (Exh. KEDNE/PJM-1, at 16; Tr. 2, at 199). In order to establish the appropriate level of insurance expense, the Company has performed a policy-by-policy analysis to compare the premium costs for each policy renewed for 2003 with its test year expense for that particular policy (Exh. KEDNE/PJM-1, at 16).

2. Positions of the Parties

a. Attorney General

The Attorney General states that the Company needs to remove $9,694 associated with nuclear liability insurance that has been allocated to Boston Gas (Attorney General Reply Brief at 40, citing Boston Gas Brief at 57-58). This amount represents an allocation from Keyspan Services for insurance that protects against any claims that may result from radioactivity due to the testing of the Shoreham Nuclear Power Plant (Attorney General Reply Brief at 40, citing RR-DTE-110). This plant was built, but never operated, by the Long Island Lighting Company ("LILCo"), a predecessor company of Keyspan (id., citing RR-DTE-110). The Attorney General asserts that the Company has acknowledged that nuclear liability insurance expense should be eliminated from the cost of service (id., citing RR-DTE-110; Tr. 25, at 3428-3429).

b. Boston Gas

The Company defends its $607,287 adjustment to test-year insurance expense, stating that Boston Gas compared the premium costs associated with each insurance policy in the test year to the premium costs for each policy that has been renewed for 2003 (Boston Gas Brief at 57, citing Exhs. KEDNE/PJM-1, at 16; KEDNE/PJM-2, at 13; KEDNE/PJM-4). The Company also states that it documented the reasons for the more substantial increases in insurance expenses associated with the renewal of the Company's liability policies (Boston Gas Brief at 57, citing Exh. DTE 2-10). The Company notes that several factors affected the increase in insurance premiums, including the terrorist attacks on September 11, 2001 and the effect on the market subsequent to the bankruptcies of Enron and Kmart (id.). The Company asserts that the Department should accept the Company's proposed post-test year adjustment to increase the cost of service by $607,287 for direct and allocated insurance expenses (Boston Gas Brief at 58, citing Exh. KEDNE/PJM-2, at 13).

3. Analysis and Findings

Rates are designed to allow for recovery of a representative level of a company's revenues and expenses based on a historic test year adjusted for known and measurable changes. D.P.U. 02-24/25, at 161; D.P.U. 92-250, at 106. Boston Gas periodically solicits bids or benchmarks all of its insurance policies, through the use of an insurance broker to secure more competitive insurance rates, as well obtain coverages not otherwise available (RR-AG-31; Tr. 2, at 209; Tr. 8, at 914). In addition, the Company receives benefits from retaining its relationships with its liability insurance carriers in the form of continuity credits

(Tr. 2, at 207-208). Based on the above considerations, the Department finds that the Company has taken reasonable measures to control its property and liability insurance expenses.

However, Boston Gas has proposed to include in its cost of service $9,694 in nuclear liability insurance premiums that had been allocated to the Company from Keyspan Services (Exh. KEDNE/PJM-4, at 1; RR-DTE-110; Tr. 25, at 3428-3429). It is not reasonable for Massachusetts ratepayers to incur the costs of nuclear liability insurance that covers Keyspan's electric generation assets that are not within Boston Gas' service territory. Although the Company stated that it would remove this expense from cost of service, the Company's revised cost of service schedules fail to account for this deletion (Exh. KEDNE/PJM-2 [rev. 3] at 13; RR-DTE-110). Therefore, the Department will reduce Boston Gas' proposed cost of service by $9,694 for nuclear liability insurance expense, resulting in a pro forma property and liability insurance expense of $597,593.

R. Keyspan Services Expenses

1. Introduction

As a result of the 2002 merger between Keyspan and Eastern Enterprises, Boston Gas became a wholly-owned subsidiary of Keyspan (Exhs. KEDNE/JFB-1, at 7; AG 1-2B(1)(a) at 5; RR-AG-15). As a registered holding company subject to the jurisdiction of the SEC, Keyspan is required to carry out any sharing of services among its affiliates through a centralized service company, which it has organized as Keyspan Services (Exh. KEDNE/JFB-1, at 15-16). All corporate and management services provided to Boston Gas are carried out

through Keyspan Services under a written agreement approved by the SEC (id. at 16, 19; Exh. KEDNE/PJM-3; RR-AG-15; Tr. 2, at 213).

Boston Gas entered into an agreement with Keyspan Services for various corporate and administrative services on January 1, 2002 (Exh. KEDNE/PJM-3, at 1). Under this agreement, Keyspan Services provides a range of administrative services to the Company in the areas of corporate affairs, customer service, environmental, executive and administrative, financial, human resources, information technology, legal and regulatory, operating services, and strategic planning and performance (id. at 27). As required by SEC regulations, these services will be provided to the Company at cost (Tr. 1, at 36-37). While this contract was reviewed by the SEC, the Company did not submit the administrative service agreement to the Department for approval (Exh. AG 17-33 [supp.] at 24; Tr. 1, at 39-40).

Keyspan Services allocates the costs of shared services among all its affiliates, including the Company, based on a set of allocation formulas (Exhs. AG 1-28; AG 17-28; Tr. 5, at 579-584). Charges are organized on the basis of project areas (1) categorized into one of approximately 230 cost centers and (2) assigned a project number and project description (Exh. AG 1-28, at 142-210). Projects are further broken down by activities related to the individual project that are identified by a specific activity number, description, cost type, and general ledger account (id. at 1-92). Each activity is assigned one of approximately 242 allocation codes within ten allocation groups, which are used to allocate the particular expense among Keyspan's affiliates (id. at 211-297, 303-316).

During 2002, the SEC performed an audit on Keyspan's 2001 form U-5S,[85] as well as other Keyspan Services expenses for the year 2002, to ensure compliance with the rules and instructions of the Public Utility Holding Company Act of 1935 (Exh. AG 17-33 [supp.] at 1). In addition to identifying errors in the way some of Keyspan Services' project activities had been recorded, the SEC directed Keyspan Services to revise its three-point allocation formula[86] such that corporate governance costs would be equitably allocated among all of Keyspan's affiliates, including Keyspan itself (Exh. AG 17-33 [supp.] at 15-16; Tr. 1, at 41-42). This directive had the effect of requiring the reallocation of $47,098,768 out of a total of $93,630,797 in corporate governance costs that had been allocated to Keyspan Services affiliates (RR-AG-34; RR-AG-75; Tr. 1, at 10-11, 41-42). The SEC ended its examination and terminated its audit by letter dated August 18, 2003 (Exh. AG 17-33; RR-AG-78 [supp. 2]; Tr. 1, at 41-42).

As a result of the SEC audit, Keyspan Services was also required to make a number of revisions to its accounting systems effective for the year 2003 (Exhs. AG 17-33 [supp.] at 14-90; AG 23-54; Tr. 1, at 11-12). Although the SEC did not require Keyspan Services to restate or modify its cost allocations for the year 2002, the Company incorporated the results of the SEC audit into its test year Keyspan Services charges, thereby reducing Keyspan

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85 Form U-5S is the annual return that registered holding companies, such as Keyspan, must file with the SEC (Exh. AG 1-2K(4)(a)).

86 The three-point allocation formula is used when no direct or other reasonable cost-benefit relationship can be determined. The formula is based on an equal weighting of revenues, assets, and expenses (Exhs. KEDNE/PJM-3, at 16-17; AG 17-33 [supp.] at 14).

Services' allocation to Boston Gas during 2002 by $491,957 (Exhs. KEDNE/PJM-12; AG 23-54; RR-AG-34; RR-AG-75; Tr. 1, at 11-12).

2. Boston Gas Proposal

During the test year, Boston Gas booked $93,795,000 in Keyspan Services charges, of which $78,955,000 was recorded under various O&M expense accounts and the remaining $14,840,000 was charged to clearing accounts (Exh. AG 1-2B(8)(a) at 5). The Company proposes a number of adjustments to its test year Keyspan Services expenses, resulting in a net decrease in O&M of $1,759,804 (Exh. KEDNE/PJM-2 [rev. 2] at 26).[87] First, the Company proposes to eliminate the following expenses: (1) $125,358 in Keyspan Services' general expenses that the Company does not consider to be includable in rates under Department ratemaking precedent; (2) $548,968 in Keyspan Services charges related to brand strategy; (3) $759,474 in Keyspan-sponsored corporate memberships; and (4) $11,565 in Keyspan Services-related strike contingency expense (Exhs. KEDNE/PJM-1, at 28-29; KEDNE/PJM-2 [rev. 2] at 26; AG 1-28, at 331-359). Each of these costs was allocated to Boston Gas during the test year using the respective allocation formulas, but the Company elected to remove them from cost of service based on its determination that the Department would exclude these costs were they directly incurred by Boston Gas (Exhs. KEDNE/PJM-1, at 29).

Second, the Company proposes to increase its test year expense by $149,255 in order to recognize Keyspan's sale of its Midland Enterprises operations during the test year. The sale

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87 The Company's schedules include an additional reduction of $425,031 associated with incremental Essex-related expenses (Exh. KEDNE/PJM-2 [rev. 2] at 26). Incremental Essex-related expenses are addressed in Section IV.S, below.

required adjustments to several of Keyspan Services' allocation formulas that resulted in Boston Gas incurring a larger share of costs formerly absorbed by Midland Enterprises (Exh. KEDNE/PJM-2 [rev. 2] at 26; Tr. 1, at 10). Third, the Company reduced its test year expense by $473,694 to incorporate the cost reallocation required by the SEC audit (Exh. KEDNE/PJM-2 [rev. 2] at 26; KEDNE/PJM-12; KEDNE/PJM-13; Tr. 1, at 10-13; Tr. 2, at 240-241).

3. Positions of the Parties

a. Attorney General

i. Introduction

The Attorney General argues that rates based on Keyspan Services' test year costs are unrepresentative of the costs Boston Gas will incur during the period that rates will be in effect (Attorney General Brief at 20). Specifically, the Attorney General raises concerns over: (1) the lack of Department approval of the Keyspan Services agreement; (2) the effects of Keyspan Services' operations on the validity of the Company's test year; (3) the need to apply a "no net harm" standard implicit in G.L. c. 164, § 96 in reviewing the proposed rate increase; (4) the results of the SEC audit; and (5) the Company's accounting practices (id.). Based on these concerns, the Attorney General argues that the Department should deny the requested rate increase in its entirety (id.; Attorney General Reply Brief at 2). In the alternative, if the Department does allow recovery of the Keyspan Services costs, the Attorney General argues that the Department should order the adjustments (as discussed beginning in

Section IV.R, below) so that the costs are "fair, equitable, and representative" (Attorney General Brief at 20-21).

ii. Keyspan Services Agreement

The Attorney General contends that Boston Gas has failed to seek Department approval, pursuant to G.L. c. 164, § 94B and 220 C.M.R. § 12.00 et seq., of various affiliate contracts with Keyspan Services, which operate under an indefinite term and, therefore, cover a period of more than one year (Attorney General Reply Brief at 9-10, citing Exh. KEDNE/PJM-3, at 1, 3 § 3.2). The Attorney General argues that, by entering into renewable one-year contracts with Keyspan Services, the Company has attempted to evade the Department's regulatory authority (Attorney General Brief at 3; Attorney General Reply Brief at 10, citing Exh. AG 1-2(B)(1)(a) at 3; Tr. 1, at 41-42).

iii. Representativeness of Test Year Expenses

Because the test year is the first year that Boston Gas' operations have been fully integrated with Keyspan Services, the Attorney General contends that, for various reasons, the Company's test year costs are not representative (Attorney General Brief at 21; Attorney General Reply Brief at 2). Specifically, the Attorney General points to the complexity of the Company's accounting and the just-recently developed the CRIS and Oracle information systems[88] as demonstrating the uniqueness of the test year (Attorney General Brief at 21). Because of the lack of representative historical Keyspan Services performance data, the Attorney General concludes that the Department must reject any request by Boston Gas for

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[88] Section III.D, above.

rates based on these expenses, especially in view of the possibility that the term of the PBR plan could be up to ten years (id. at 20-21).

iv. "No Net Harm" Standard

The Attorney General argues that, although the Company is seeking to recover over $20 million in direct system integration costs arising from the Keyspan merger, Boston Gas has failed to quantify savings arising from the merger, thereby warranting disallowance of these acquisition-related costs (id. at 10; Attorney General Reply Brief at 8). The Attorney General also contends that the Company's "vague statement" of merger-related savings is insufficient to meet its burden of proof to demonstrate savings that offset the costs of the merger (Attorney General Reply Brief at 10-12). According to the Attorney General, Boston Gas is, in effect, seeking Department approval of a number of important cost effects arising from the Keyspan/Eastern Enterprises merger without the requisite showing of "no net harm" to ratepayers of the former Eastern Enterprises companies, as required by G.L. c. 164, § 96 (Attorney General Brief at 9). Although the Company did not seek Department approval of the merger, the Attorney General maintains that Boston Gas should be held to the "no net harm" standard implicit in G.L. c. 164, § 96, and demonstrate that the Company's customers were not harmed by the Keyspan acquisition (id.; Attorney General Reply Brief at 7-8)

v. SEC Audit

In reference to the SEC audit, the Attorney General contends that the Company has resisted efforts to determine whether Boston Gas is in actual compliance with SEC requirements (Attorney General Brief at 22). The Attorney General maintains that, even if the

SEC closes the audit, the following unresolved issues remain: (1) only $28 million in corporate governance costs have been reallocated; (2) minimal costs have been allocated to nonregulated utilities; (3) financial planning costs, including merger and acquisition resource planning costs, have not been included in the reallocation of corporate governance costs; (4) only selected invoices have been reallocated by Keyspan Services; and (5) no Keyspan Services costs have been allocated to Essex (id. at 23-24). Therefore, the Attorney General urges the Department to (1) remove the effects of all reallocated corporate governance costs from Boston Gas' cost of service, (2) reallocate all costs associated with the categories identified by the sample transactions, and direct the Company to incorporate these reassignments in its accounting systems, and (3) develop accounting systems that maintain Essex as a discrete entity in the development of Keyspan Services charges (id. at 24-25).

vi. Accounting Practices

In addition to his concerns with the Company's accounting and cost allocation methods, the Attorney General argues that the Company's accounting books are replete with entries that are not recorded in compliance with the Department's USOA (id. at 4). First, the Attorney General contends that Boston Gas has inappropriately combined the books of Essex, a separate and distinct regulatory entity, with those of the Company (Attorney General Reply Brief at 2, citing Exhs. KEDNE/PJM-2; AG 11-1; KEDNE/PJM-1, at 21). The Attorney General maintains that, as a result, the information contained in both the Company's and Essex's annual returns to the Department has been rendered useless (id.).

Second, the Attorney General contends that the Company has inappropriately used Account 922 (Administrative Expenses Transferred - Credit) to transfer $15,325,000 in gas acquisition and local production and storage costs to costs of gas accounts (Attorney General Brief at 20, n.12; Attorney General Reply Brief at 2). The Attorney General argues that these transferred costs are not appropriately charged to Account 922, but instead should be booked to the appropriate O&M accounts prescribed by the USOA for gas companies (id. at 20-21, n.12; Attorney General Reply Brief at 2, citing Exh. AG 23-14). Finally, the Attorney General maintains that Boston Gas booked the majority of Keyspan Services costs to the Company's administrative and general accounts (Attorney General Brief at 20-21, n.12, citing Exhs. AG 23-14; AG 23-9). The Attorney General argues that charges from Keyspan Services should be booked instead to the Company's respective accounts to which the costs directly relate, as required by the Department's USOA for gas companies (Attorney General Brief at 20, n.12, citing Exh. AG 31-6; Tr. 22, at 2983; Tr. 23, at 3156-3158; Attorney General Reply Brief at 2, citing Exh. AG 31-6).

As a result of these alleged accounting violations, the Attorney General argues that the Department should deny Boston Gas' rate increase in total (Attorney General Reply Brief at 3). Moreover, the Attorney General urges the Department to direct the Company to bring its accounting into compliance with the USOA for gas companies (id.).

b. Boston Gas

i. Introduction

Boston Gas argues that the Attorney General's arguments relative to both Keyspan Services costs and the use of a 2002 test year are devoid of merit and record support (Boston Gas Brief at 18). Also, the Company maintains that it has properly identified and excluded from cost of service Keyspan Services expenses not properly chargable to Boston Gas, that there is no basis for further reallocating or reassignments of Keyspan Services charges, and that Essex-related cost allocations have been fully identified (id. at 18-19).

ii. Keyspan Services Agreement

The Company maintains that there is no statutory obligation or precedent requiring Department approval of Boston Gas' contract with Keyspan Services, but only the requirement to file affiliate contracts with the Department for informational purposes (id. at 8). Therefore, Boston Gas concludes that Department approval of the Keyspan Services contract is not required (id.).

iii. Representativeness of Test Year Expenses

The Company argues that the Attorney General has failed to point to any factor involving Keyspan Services that would render 2002 as unreliable for a test year (id. at 16). Boston Gas argues that its selection of calendar year 2002 as the test year for its rate case is in conformance with Department requirements that test years be based on historical data (id. at 13, citing D.T.E. 02-24/25, at 76; D.P.U. 88-67 at 77; Commonwealth Electric Company, D.P.U. 87-122, at 13 (1987); Eastern Edison Company, D.P.U. 1580, at 13-17 (1984)). The

Company maintains that its proposed test year also conforms to the Department's requirement that the test year represent a twelve-month period that does not overlap the test year used in a utility's previous rate case (Boston Gas Brief at 13, citing Massachusetts Electric Company, D.P.U. 19257, at 12 (1977).

The Company maintains that accounting and cost allocations issues will always be complex, regardless of the test year selected (Boston Gas Brief at 15). The Company further argues that the Attorney General has failed to point to any evidence in the record linking either historical performance data, accounting and cost allocation issues, or its new information systems to a showing that the test year is unrepresentative of Boston Gas' future level of costs (id. at 16-17). In fact, the Company maintains that it has gone to great lengths in this proceeding to explain the workings of Keyspan Services (id. at 17).

iv. "No Net Harm" Standard

Boston Gas disputes the Attorney General's argument that a "no net harm" standard need be adopted to evaluate the Company's rate request (id.). The Company argues that the Attorney General's argument as legally erroneous because (1) the Department has no authority to review the merger of holding companies under G.L. c. 164, § 96, and (2) the Company has not sought to recover any merger-related costs (Boston Gas Reply Brief at 17-18). The Company contends that the Attorney General's position would lead to an "impossibly confused" legal standard for proceedings brought under G.L. c. 164, § 94 (id. at 19, 24-25).

The Company also argues that the Attorney General has misapplied the burden of proof standard (id. at 20). According to Boston Gas, the Attorney General's claim that

merger-related costs are included in rates does not shift the burden of proof to the Company to show merger-related savings, but at most shifts the burden of proof to Boston Gas to show that the specific costs are not merger-related (id. at 23-24).

v. SEC Audit

Boston Gas contends that the Attorney General's reliance on the SEC audit as a demonstration of the reliability of the test year level of Keyspan Services charges is misplaced (Boston Gas Brief at 14). The Company argues that because the SEC audit officially as been terminated, there are no unresolved issues (id. at 15, citing RR-AG-78 [supp.]).

As to specific issues raised during the SEC audit that are disputed by the Attorney General, Boston Gas maintains that (1) the bulk of corporate governance costs were allocated using factors other than the three-point formula allocators, (2) Keyspan Services provides only minimal services to unregulated affiliates, (3) financial planning costs were not reallocated by the SEC, (4) shareholder costs have already been removed from the Company's cost of service, and (5) the SEC reviewed all documentation related to the allocation factors for the years 2001 through 2003 (Boston Gas Brief at 17-18).

vi. Accounting Practices

The Company argues that the Attorney General's contention that Boston Gas has inappropriately recorded various accounting transactions involving Keyspan Services and Essex is misleading and unfounded (id. at 9; Boston Gas Reply Brief at 4). The Company maintains that Boston Gas and Essex are two separate companies, with separate books for each operation, and that all costs directly attributable to Essex are booked directly to Essex (Boston

Gas Reply Brief at 5). The Company states that only nonincremental costs associated with Essex have been assigned to Boston Gas, as previously directed by the Department (id. at 4, citing Eastern-Essex Acquisition, D.T.E. 98-27-A (1999)).

Turning to its use of Account 922 to record CGAC-related expenses, the Company argues that the Attorney General has failed to cite any accounting rule, Department regulation or ratemaking practice requiring his proposed accounting protocol (Boston Gas Reply Brief at 5). Boston Gas contends that the USOA for gas companies had never contemplated the ratemaking treatment of O&M costs through the CGAC (id.). Additionally, the Company maintains that the amounts booked to Account 922 are excluded from the calculation of its revenue deficiency and are fully evident in the Company's annual returns to the Department (id. at 6).

Regarding the Company's booking of Keyspan Service charges to administrative and general accounts, Boston Gas argues that the Attorney General has again failed to cite any accounting rule, Department regulation or ratemaking practice requiring his proposed accounting protocol (id.). Boston Gas notes that the Attorney General's own cost of service witness stated that accounting rules would permit the protocol followed by the Company (id., citing Tr. 20, at 2710-2711). Additionally, the Company maintains that all costs incurred by Keyspan Services on behalf of Boston Gas are charged on the basis of allocation formulas that apply to specific projects and project activities, with overhead added to Keyspan Service's direct labor charges before being billed to Boston Gas (Boston Gas Reply Brief, citing Exhs. KEDNE/PJM-1, at 6; AG 1-28; KEDNE/PJM-14, at 4; Tr. 5, at 580. 584; Tr. 17,

at 2307). Therefore, the Company considers its accounting treatment of Keyspan Services charges to be appropriate (Boston Gas Reply Brief at 7).

4. Analysis and Findings

a. Introduction

In order to qualify for inclusion in rates, any payments by a utility to an affiliate must be (1) for activities that specifically benefit the regulated utility and that do not duplicate services already provided by the utility, (2) made at a competitive and reasonable price, and (3) allocated to the utility by a formula that is both cost-effective and nondiscriminatory within both those services specifically rendered to the utility by the affiliate and for general services which may be allocated by the affiliate to all operating affiliates. D.T.E. 02-24/25, at 180; Hingham Water Company, D.P.U. 88-170, at 21-22 (1989); AT&T Communications of New England, D.P.U. 85-137, at 51-52 (1985); Oxford Water Company, D.P.U. 1699, at 12-14 (1984). We will address the merits of the each of the Attorney General's issues in sequence before turning to the Company's proposed adjustments.

b. Keyspan Services Agreement

Unless otherwise authorized by the Department, gas or electric companies are not permitted, pursuant to G.L. c. 164, § 94B, to enter into contracts with affiliated companies for a term in excess of one year that requires compensation to the affiliated company, unless the contract contains a provision subjecting the amount of compensation to be paid thereunder to review and determination by the Department in any proceeding brought under G.L. c. 164,

§§ 93 or 94. As defined by G.L. c. 164, § 85, Keyspan Services is an affiliated company of Boston Gas.

The Keyspan Services agreement may be terminated by either Boston Gas or Keyspan Service upon 60 days' advance notice to the other party (Exh. KEDNE/PJM-3, at 3). While the indefinite term of the Keyspan Services contract renders the effective term as more than one year, Article 1.4 (b) of the contract provides:

> Notwithstanding anything in this Agreement to the contrary. . . Boston Gas. . . will not accept services from [Keyspan Services] hereunder if the cost to be charged for such services differs from the amount of the charges. . . Boston Gas. . . [is] permitted to incur under [its] respective state and the rules, regulations and orders of [its] respective state Public Utility Commission or its' (sic) equivalent promulgated thereunder.

(id.). This contract language subjects the amount of compensation to be paid under the Keyspan Services contract to review and determination by the Department in any proceeding brought under G.L. c. 164, §§ 93 or 94. The Department clearly has jurisdiction to determine the recoverability of expenses paid by Boston Gas for services rendered by Keyspan Services. Consistent with § 94B, Boston Gas could have secured prior approval of the contract but prior Department approval of the contract was not required by the Department under G.L. c. 164, § 94B, because the contract "contains a provision subjecting the amounts of compensation to be paid thereunder to review and determination by the [D]epartment" under § 93 or § 94. The final sentence of § 94B reinforces the "unless" clause of its first sentence. The point could not be clearer. The Attorney General's claim is without merit.

c. Representativeness of Test Year Expenses

Turning to the Attorney General's argument that the integration of Keyspan Services creates a fatal defect in the Company's selection of 2002 as a test year, the Department has required that test years consist of a twelve-month period of historical data that does not overlap the test year used in a utility's previous rate case. D.T.E. 99-118, Interlocutory Order at 8 (2001); D.P.U. 88-67 (Phase I) at 77; D.P.U. 1720, Interlocutory Order at 7-11; D.P.U. 1580, at 13-17; D.P.U. 19257, at 12. The Company's test year is based on calendar 2002 operations, with no overlap from the calendar 1995 test year used in the Company's previous rate proceeding in D.P.U. 96-50.

The Attorney General points to the lack of historical data demonstrating the "successful integration" of services provided by Keyspan Services, the newness of information systems, and the complexities of the Company's cost accounting as a basis for rejecting the Company's test year despite its compliance in form with Department requirements. However, Boston Gas began relying on Keyspan Services for its corporate officers and information technology areas on January 1, 2001, and has been operating on a fully-integrated basis with Keyspan Services since January 1, 2002 (Exh. KEDNE/JFB-1, at 18; Tr. 2, at 213-214). Therefore, Boston Gas has been relying on Keyspan Services for all of its shared services over the entire test year.

Accounting and cost allocations issues associated with service companies will always be complex, regardless of the test year selected or how many years of historical data are available to the fact finder. To the extent that a particular service company allocation or expense is determined to be inequitable, erroneous, or nonrepresentative, the Department has the ability

to make such adjustments as may be appropriate to ensure that ratepayers are only responsible for reasonable and appropriate costs. D.T.E. 98-51, at 27-30; D.P.U. 1699, at 13; see also Commonwealth Electric Company v. Department of Public Utilities, 397 Mass. 361, 379 (1986).

While some elements of Boston Gas' presentation of its Keyspan Services charges could have been provided on a more systematic basis to facilitate Department and intervenor review, there is quite sufficient information in this proceeding to evaluate the Company's request. Moreover, because the SEC audit examined both Keyspan Services' allocation methods and expenses for the year 2002, the Department finds that the SEC audit provides an independent assessment of Keyspan Services' charges during the test year, thereby enhancing the reliability of the Company's test year data. The SEC review appears to have been thorough and systematic; its weight far exceeds the generalized objections raised here (Exhs. AG 17-33; AG 17-33 [supp.]). Therefore, the Department declines to exclude all Keyspan Services charges from cost of service based on the choice of a 2002 test year. Also, the Department finds that the Company's proposed test year level of Keyspan Services charges do not distort the interrelation among revenues, expenses, and plant to the point where the test year data becomes unreliable. The Department has examined Boston Gas' test year and proposed Keyspan Services charges, and has made appropriate adjustments as described below.

d. "No Net Harm" Standard

The Attorney General argues that the Department's "no net harm" standard, as used in § 96 merger review proceedings, must also be applied in this § 94 rate case investigation.

Therefore, the Department must determine whether quantification of merger-related savings is required in this proceeding. It is undisputed that neither Eastern Enterprises, a Massachusetts business trust and parent of Boston Gas, nor Keyspan, a holding company organized as a New York corporation, were or are Massachusetts operating utilities (RR-AG-15(a) at 3-9). Therefore, the acquisition of Eastern Enterprises by Keyspan did not require Department approval under G.L. c. 164, § 96 and the application of a "no net harm" standard is inappropriate in this case. See BECo/ComEnergy Acquisition, D.T.E. 99-19, at 7 (1999).

General Laws c. 164, § 94 requires Department approval of any change in rates sought by a jurisdictional utility. Had Boston Gas sought a merger-related rate plan as a component of its acquisition by Keyspan, the Department would have evaluated the business combination under the purview of G.L. c. 164, § 94. Id.; Attorney General v. Department of Telecommunications and Energy, 438 Mass. 256, 268-269 (2003). The Company neither proposed nor submitted a rate plan as part of its acquisition by Keyspan. However, in the context of this § 94 rate case, the Department has the authority to decide the reasonableness of the resulting costs allocated to Boston Gas through Keyspan Services, and, thereby, determine their rate recovery. D.P.U. 98-51, at 30.

In a rate case proceeding, there is no explicit requirement that merger-related savings be demonstrated, unless the petitioning utility is seeking to recover costs that are directly related to a merger, such as an acquisition premium. NIPSCo/Bay State Acquisition, D.T.E. 98-31, at 44-46 (1998). The Company is only seeking to recover costs that are non-incremental to Boston Gas in this proceeding, which are costs that the Company would

have incurred absent the mergers. Therefore, the Department finds that the Company need not make a showing of merger-related savings in this proceeding. Instead, the Department will rely on its long-standing ratemaking practices to evaluate the propriety of Boston Gas's rate proposal.

e. SEC Audit

Concerning the results of the SEC audit on the reliability of the Company's test year data, the SEC has officially terminated its audit of Keyspan Services (RR-AG-78 [supp.]). While the SEC's concerns have apparently been addressed to its satisfaction, the Department remains obligated to examine the resulting costs that are allocated to Boston Gas to determine whether these expenses should be borne by ratepayers. The Attorney General identifies four areas of concern regarding the effects of the SEC audit on the charges Keyspan Services allocates to the Company.

First, the Attorney General contends that Keyspan Services failed to reapportion all of its corporate governance costs, as directed by the SEC. The SEC directed Keyspan Services to revise its three-point allocation formula to ensure that Keyspan was allocated a fair and equitable portion of common costs (Exh. AG 17-33 [supp.] at 13-19, 48-53). This reallocation affected $47,098,768 out of a total $93,630,797 in Keyspan Services corporate governance expenses, primarily in the areas of strategic planning, public affairs, corporate secretary, and executive (RR-AG-75, at 1-7). Other Keyspan Services corporate governance costs, such as many of the projects listed in the areas of controller and compensation, and benefits, were not

allocated with the three-point formula and, thus, were not affected by the SEC's directive (id. at 1-6).

The Department has examined the allocation factors used by Keyspan Services, including the revised three-point allocator, taking into consideration the basis for the various allocation factors. The sharing of costs for Boston Gas' corporate affairs, customer service, environmental, executive and administrative, financial, human resources, information technology, legal and regulatory, operating services, and strategic planning and performance areas among Keyspan's affiliates provides benefits to ratepayers of Boston Gas that outweigh the costs that would be incurred if the Company had to bear the total cost of these services on a stand-alone basis. Although other ways could be devised to allocate costs among Keyspan's affiliates, none of the parties in this proceeding have offered alternative cost allocation methods. The existence of other possible allocation outcomes does not render the Company's allocation method invalid. D.P.U. 88-135/151, at 83. Based on our review, the Department finds that the method used to allocate Keyspan Services' general services charges to Boston Gas, including the revised three-point allocator and other general allocation factors, benefits Boston Gas, is provided at cost, and produces both cost-effective and nondiscriminatory results for services that are allocated generally in this manner among Keyspan's operating affiliates. The Department also finds that the method used to allocate Keyspan Services' direct charges for services specifically rendered to Boston Gas benefits the Company, is provided at cost, and produces both cost effective and nondiscriminatory results for specific services rendered to

Boston Gas by Keyspan Services. Therefore, the Department approves the use of the revised allocators used by Keyspan Services to allocate a portion of common costs to Boston Gas.

Second, the Attorney General objects to the level of charges allocated to Keyspan's nonutility affiliates on the basis of the SEC audit. However, the SEC's initial concerns about the three-point allocator appear to have been primarily focused on the absence of any allocation of costs to Keyspan, which had the incidental result of minimal costs allocated to nonutility operations (Exh. AG 17-33 [supp.] at 51). In order to address the SEC's concerns, Keyspan Services revised its three-point formula to allocate costs to Keyspan as well as other affiliates. This reallocation of costs to Keyspan resulted in a lower overall allocation of costs among both utility and nonutility affiliates of Keyspan (RR-AG-34). While the Attorney General is correct that the revised three-point formula results in a smaller allocation to nonutility operations, it is self-evident that if Keyspan was allocated a portion of Keyspan Services' charges, a reduction in overall allocations would result for all affiliates. Therefore, the decrease in the overall allocation to nonutility operations does not constitute a defect in the three-point allocator.

Third, the Attorney General objects to Keyspan Services' method of allocating financial planning expenses to Boston Gas, claiming that the Company failed to comply with the SEC's directives on corporate governance. However, the SEC's directives on corporate governance expense allocators pertain only to Keyspan Services' use of allocation formulas that failed to assign costs to Keyspan (Exh. AG 17-33 [supp.] at 18, 48-52). Corporate governance costs that were allocated with factors based on other methods were not affected by the SEC's

directives. Therefore, the Attorney General's concern over the Company's use of its chosen allocators for financial planning expenses is misplaced.

While the Department declines to reallocate the Company's financial planning expenses, Keyspan Services allocated $104,816 in merger and acquisition resource planning expenses to Boston Gas as a component of financial planning expenses during the test year (Exh. KEDNE/PJM-2 [supp.] at 142). Merger and acquisition planning expenditures by the parent of an operating company provide more in the way of benefits to the parent company, such as Keyspan, than to the operating subsidiary. See Glacial Lake Charles Aquifer Water Company, D.P.U. 88-197, at 8 (1989). Therefore, the Department finds that the Company has failed to demonstrate that its mergers and acquisition resource planning expenditures are appropriately included in cost of service. D.P.U. 92-111, at 68, 205. Accordingly, the Department will remove the $104,816 in merger and acquisition resource planning expenses from the Company's cost of service.

Fourth, the Attorney General has objected to the inclusion of the Company's allocated portion of expenses related to shareholder and board of director meetings, because the SEC audit only examined a sampling of invoices related to these costs (Exh. AG 17-33 [supp.] at 55-65).[89] During the test year, Boston Gas was allocated $25,121 in annual meeting expense and $87,016 in board of director expenses (Exhs. KEDNE/PJM-2 [supp.] at 141; AG 17-33 [supp.] at 63). The Company's 2001 SEC corporate governance analysis demonstrates that the

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[89] The SEC audit reviewed $293,663 in invoices related to shareholder meetings out of a total expense of $950,807 (Exh. AG 17-33 [supp.] at 56, 60).

revisions to Keyspan Services' three-point formula results in the elimination of all shareholder meeting and board of director expenses from Boston Gas' cost of service (see Exhs. KEDNE/PJM-12, KEDNE/PJM-2 [rev. 2] at 26). The Company has excluded these expenses from its proposed cost of service, therefore, the Attorney General's concern about the recovery of these expenses is moot.

f. Accounting Practices

Concerning the Attorney General's allegation that Boston Gas and Essex have commingled their books, the Company and Essex are separate companies, each with its own sets of books and accounts (Tr. 1, at 51). Instead, the Attorney General's objections are related to the issue of the SEC-approved allocation formulas not recognizing Essex as a separate entity. The SEC's policies governing service company allocations do not require the separation of Essex-related costs from those of Boston Gas (Exh. KEDNE/PJM-1, at 21; Tr. 8, at 957-958; Tr. 20, at 2756)). However, the SEC's service company allocation policies do not preempt the Department in its rate setting role. D.P.U. 98-51, at 25-27; 15 U.S.C. §§ 79t(b), 79u.

The SEC's allocation process makes no determination as to reasonableness or appropriateness under the standards that would be applied by the utility commissions in the states in which a holding company's retail subsidiaries are located. D.P.U. 98-51, at 30. Therefore, there is nothing in the SEC's approval of the Keyspan Services allocation formula that impinges on the Department's jurisdiction to determine whether service company charges are reasonable and appropriate for recovery from Massachusetts ratepayers. While the

Keyspan Services allocation formulas do not treat Essex as a separate entity, the Company has identified and separated costs that it considers attributable to Essex (Exhs. KEDNE/PJM-2 [rev. 2] at 26; AG 11-1; AG 23-53). Therefore, the Department finds that the Attorney General's concerns on Keyspan Services' failure to allocate a portion of its charges directly to Essex are unfounded.

The Attorney General raises concerns over the Company's use of Account 922 for gas acquisition costs and local production and storage costs. The Department's accounting systems, including the USOA for gas companies, codified in 220 C.M.R. § 50.00 et seq., represent a system whereby costs are sorted and categorized to provide the Department with information on utility operations and aid in the review of utility costs; they do not establish either the reasonableness per se of the reported costs or the ratemaking treatment to be accorded such costs. Boston Edison Company, D.P.U./D.T.E. 97-95, at 77 (2001). The Department's ratemaking process takes into consideration many factors other than account balances. Therefore, the existence of a particular category of costs in the Department's system of accounts implies no judgment as to the reasonableness of that cost in a given instance. Id.; Reclassification of Accounts of Gas and Electric Companies, D.P.U. 4240-A, Introductory Letter (May 19, 1941); See also Boston Gas Company v. City of Newton, 425 Mass. 697, 706 (1997). The booking of a particular expense in accordance with the USOA for gas companies does not establish the reasonableness per se of that expense for ratemaking purposes.[90] It

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[90] By way of example, although the USOA for gas companies specifies that institutional or goodwill advertising be booked to Account 930 (Miscellaneous General Expenses), the (continued…)

therefore follows that the Department's USOA for gas companies is not intended to detail the particular ratemaking treatment or cost allocation that may be accorded an expense.

The instructions for Account 922 as found in the USOA for gas companies provide clear guidance on the purpose of this account. Account 922 is intended to credit "administrative expenses recorded in Account 920 (Administrative and General Salaries) and Account 921 (Office Supplies and Expenses) which are transferred to construction costs or to nonutility accounts." 220 C.M.R. § 50.00 et seq. Gas acquisition costs and local production and storage costs are not related to administrative and general salaries or office supplies and expenses. Therefore, Boston Gas' use of Account 922 to transfer utility costs for ratemaking purposes is inconsistent with 220 C.M.R. § 50.00 et seq..[91] Accordingly, the Company is directed to revise its accounting books to make the appropriate corrections to Account 922 and related accounts. Boston Gas is also directed to cease its use of Account 922 as a cost allocation vehicle.

Concerning the booking of Keyspan Service charges to administrative and general accounts, while the USOA for gas companies provides for separation of payroll overheads into their respective accounts, it is silent on the inclusion of service company overhead charges in

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[90] (…continued)
Department's policy is to exclude this type of advertising from cost of service. D.P.U. 91-106/138, at 60; D.P.U. 90-121, at 121.

[91] While Boston Gas argues that the Department has not previously objected to the Company's use of Account 922, it is not intuitive from a review of the reported Account 922 balances in the Company's annual returns to the Department as to the actual purpose of the transfers (Exh. AG 1-2B(1)(a) at 47).

administrative and general accounts. 220 C.M.R. § 50.00 et seq. However, the instructions for both Accounts 920 and 921 specify that a utility may assign a series of subaccounts that are "appropriate to the departmental or other functional organization of the utility." 220 C.M.R. § 50.00 et seq. Because Keyspan Services' cost allocation formulas differ between projects and project activities, overhead costs such as employee benefits and payroll taxes must be added to labor charges before being charged or allocated to Boston Gas (Exh. KEDNE/PJM-14, at 4; Tr. 5, at 580; Tr. 17, at 2307-2308). Therefore, while Keyspan Services' labor charges are still booked to Accounts 920 and 921, associated payroll overheads cannot be booked to separate accounts, and therefore need to be booked in their entirety, at least initially, to Accounts 920 and 921 (Exhs. KEDNE/PJM-14, at 4; DTE 5-33; Tr. 17, at 2307-2308; Tr. 25, at 3519-3521). The Attorney General states that if a service company charge was billed as part of a fully-loaded labor billing, as is done by Keyspan Services, then the expense could be booked to Accounts 920 and 921, as appropriate (Tr. 20, at 2710-2711). If a utility maintains its books so that service company charges can be recorded in appropriate subaccounts that are available for review by the Department, the requirements of 220 C.M.R. § 50.00 et seq. would be fulfilled. The Department finds that Boston Gas is able to maintain accurate information on the level of payroll overheads it is billed from Keyspan Services (Exh. KEDNE/PJM-2, at 6-11). Therefore, the Department finds no evidence that Boston Gas has failed to properly record the charges it incurs from Keyspan Services.

In reaching this determination, the Department notes its concerns about some of the Company's record keeping procedures. See Lowell Gas Company, D.P.U. 19666/19677,

at 35 (1979). We have long acknowledged the importance that comprehensive accounting systems, such as those provided by the annual returns to the Department, have in the regulatory process for both the Department and other interested persons. D.P.U. 95-92, at 3; Hutchinson Water Company, D.P.U. 85-194, at 16-17 (1986); Blackstone Gas Company, D.P.U. 19579, at 3-4 (1979). Boston Gas is directed to investigate the feasibility of booking its Keyspan Services charges directly by account in the USOA for gas companies. The Company shall report its findings to the Department within six months from the date of this Order.

g. Proposed Company Adjustments

Boston Gas proposes to eliminate $2,194,835 in test year Keyspan Services charges related to various expenses that the Company determined would be disallowed under Department precedent, as well as to recognize the effects of the reallocating from the SEC audit, Keyspan's divestiture of Midland Enterprises, and incremental Essex charges (Exh. KEDNE/PJM-2 [rev. 2] at 26). The Company-identified disallowable expenses are primarily associated with allocations of costs attributable to New York operations, executive chauffeurs, brand strategy, corporate memberships, and strike contingency (Exh. KEDNE/PJM-2 [supp.] at 127). The Department finds that the Company has appropriately removed its allocated share of New York operations, executive chauffeurs, brand strategy, and corporate memberships from its proposed cost of service. Because there is no evidence that the $11,565 in Keyspan Services strike contingency expense is related to the operations of Boston Gas, the Department accepts the Company's removal of these expenses from cost of

service. Additionally, the Department finds that Boston Gas has properly recognized the effects of the SEC audit and the divestiture of Midland Enterprises on its share of Keyspan Services charges. The Company's incremental charge related to Essex are addressed in Section IV.S, below.

h. Conclusion

Based on the foregoing analysis, the Department has removed $104,816 in merger and acquisition resource planning costs from the Company's proposed Keyspan Services charges. Accordingly, the Company's proposed cost of service shall be reduced by $104,816.

Concerning the Attorney General's allegations of accounting irregularities, the Department has found that while Boston Gas has somewhat misconstrued the USOA for gas companies in its booking of CGAC-related costs, the accounting "irregularities" cited are without adverse consequence. The Department has directed the Company to cease using Account 922 as a CGAC cost allocation vehicle. Beyond this directive, and the Company's required report on the feasibility of allocating its Keyspan Services charges by specific USOA for gas companies account referenced above, we find that no further action is warranted.

S. Incremental Colonial and Essex Expenses

1. Introduction

In Eastern/Essex Acquisition, D.T.E. 98-27 (1998), the Department approved the acquisition of Essex by Eastern Enterprises. As part of that proceeding, the Department allowed Eastern Enterprises to retain the cost savings resulting from the acquisition during the

term of the ten-year Essex rate plan. Id. at 66. Because Boston Gas[92] would be providing corporate and administrative services to Essex, the Department directed the petitioners to develop a cost-allocation system for transactions between the two entities (RR-AG-20).[93] Id. at 47. In order to ensure that Boston Gas customers would not subsidize Essex customers during the ten-year Essex rate plan and still allow Eastern Enterprises the opportunity to recover merger-related savings, the Department determined that Essex would only be assigned incremental costs that Boston Gas incurs to provide corporate and administrative services for Essex.[94] D.T.E. 98-27-A at 5.

The following year, the Department approved the acquisition of Colonial by Eastern Enterprises. D.T.E. 98-128. The Department concluded that the same cost-allocation principle used to account for corporate and administrative costs for Essex would be applied to transactions between Boston Gas and Colonial during the ten-year term of Colonial's rate plan. Id. at 85-86, 88-89. Therefore, the corporate and administrative functions of Colonial were consolidated into those of Boston Gas, which in turn was required to allocate to Colonial any incremental costs that the Company incurred in providing these services to Colonial (Exh.

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92 Boston Gas was a former wholly-owned subsidiary of Eastern Enterprises.

93 The Department later explained that, because use of the cost-allocation method would eliminate any opportunity for Eastern Enterprises to recover its merger-related acquisition costs, the cost-allocation system would not be used for the purpose of setting rates for Boston Gas during the ten-year duration of Essex's base rate freeze. D.T.E. 98-27-A at 4.

94 Incremental costs were defined as those costs that Boston Gas would not have incurred except for the need to serve Essex and Colonial. D.T.E. 98-27-A at 4-5; D.T.E. 98-128, at 88-89.

KEDNE/PJM-1, at 20). In 2000, Keyspan acquired Eastern Enterprises (id. at 7). Keyspan Services is now responsible for the corporate and administrative functions formerly provided by Boston Gas to Colonial and Essex (id. at 8).

The Company proposes to adjust its test year cost of service to include costs allocated to Colonial under Keyspan Services' SEC-approved allocation formula, but not considered incremental to the operations of Boston Gas (id. at 20). Therefore, the Company proposes to increase test year cost of service by $7,256,297 to account for costs allocated to Colonial by Keyspan Services, for non-incremental costs to Boston Gas (id. at 21). These costs relate to O&M activities in the following categories: (1) corporate management and administration; (2) finance; (3) human resources; (4) information technology; (5) gas supply and engineering; and (6) legal and regulatory (id.; Exh. KEDNE/PJM-2 [rev. 2] at 18).

In the case of Essex, because Keyspan Services does not recognize Essex as an independent entity for SEC allocation purposes, Boston Gas is allocated Essex's share of common costs (Exh. KEDNE/PJM-1, at 21). In accordance with D.T.E. 98-27-A, the Company has allocated to Essex $1,835,681 in Essex-related incremental costs of Boston Gas (id.; Exh. AG 11-1). The Company allocated $1,410,650 in Essex-related incremental costs to Essex (Exh. KEDNE/PJM-1, at 21). Because these costs were directly allocated to Essex from Keyspan Services, Boston Gas states that no additional adjustment to the Company's test year cost of service is required (id. at 21-22). The Company identified an additional $425,031 in Essex-related incremental costs (Exh. AG 11-1). These additional incremental costs were

removed from Boston Gas' test year cost of service through an adjustment to service company expenses (Exh. KEDNE/PJM-2 [rev.] at 26).

2. Positions of the Parties

a. Attorney General

The Attorney General contends that, although the Company is seeking to recover an additional $8.7 million in non-incremental Essex and Colonial costs, it has failed to quantify savings arising from the merger with Keyspan, thereby warranting disallowance of these costs (Attorney General Brief at 10; Attorney General Reply Brief at 9). The Attorney General contends that the Company's proposal to replace the incremental cost models approved for the Essex and Colonial acquisitions with a new cost accounting model based on SEC formulas represents a fundamental alteration to the Department's earlier decisions (Attorney General Brief at 10-12). Because the Keyspan merger materially changed the basis for the Department's earlier approvals, the Attorney General requests that the Department disallow all Essex- and Colonial-related costs included in Boston Gas' proposed cost of service (id. at 12-13; Attorney General Reply Brief at 12-13). The Attorney General reasons that there is no dispute that the Company's proposed incremental cost adjustment serves to increase the revenue requirement of Boston Gas. Because there are no merger-related savings in the cost of service before the incremental cost adjustment, the Attorney General argues that the cost of service with the incremental adjustment must mathematically be greater than the cost of service in the absence of the mergers (Attorney General Reply Brief at 13). Conversely, if the savings attributable to the merger are already on the books of the Company, the Attorney General

argues that the incremental cost adjustment is unnecessary because investors are already retaining the benefits of merger-related savings (id. at 14).

In the alternative, the Attorney General argues that, even if the Department determines some level of non-incremental costs from Essex and Colonial should be allocated to the Company, Boston Gas has failed to establish that the method used to distinguish incremental from non-incremental costs is appropriate (Attorney General Brief at 13-15). The Attorney General identifies a number of concerns with the Company's analysis, including the identification of incremental costs as actually non-incremental in nature, the selective nature of the expense categories considered by Boston Gas, and the Company's own data indicating a lack of genuine cost savings arising from the acquisition of Essex or Colonial (id. at 15-18; Attorney General Reply Brief at 14-16). The Attorney General argues that, after removing employee benefits and uncollectibles from gas O&M expense, there is an 18 percent variation between 2002 expense levels and the 1996 through 1998 average expense level, thus demonstrating that the Essex and Colonial acquisitions have failed to produce any savings from economies of scale (Attorney General Reply Brief at 15-16, citing RR-AG-101).

The Attorney General concludes that the Company has failed to establish the reliability of its incremental cost allocation method. Therefore, the Attorney General argues that the Department should reduce the Company's proposed cost of service by $8,696,000, consisting

of $6,880,000[95] in Colonial costs allocated to Boston Gas and $1,816,000[96] in Essex costs allocated to the Company (Attorney General Brief at 19; Attorney General Reply Brief at 16).

b. Boston Gas

The Company contends that it has carefully reviewed all allocations between Keyspan Services, Essex, and Colonial (Boston Gas Brief at 66). The Company argues that its proposed adjustment to include Essex- and Colonial-related non-incremental costs in the cost of service of Boston Gas is consistent with the Department's directives in D.T.E. 98-27-A and D.T.E. 98-128 (id. at 69). According to the Company, the Attorney General's proposal would result in the disallowance of costs actually incurred to provide service to Boston Gas customers (Boston Gas Reply Brief at 26).

The Company maintains that costs allocated to Colonial under the SEC formulas have been allocated to the Company only if those costs were incurred by Keyspan Services on behalf of Boston Gas, regardless of Colonial's actual participation (Boston Gas Brief at 67). The Company states that for each cost item, it applied specific criteria to determine whether the costs were considered incremental or non-incremental (id. at 67-68, citing Exh. AG 11-1). Further, the Company asserts that it recognized that because a portion of certain costs relative to areas such as field marketing, leak survey, meter operations, and similar areas are

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95 According to the Attorney General, this value represents the share of the nonincremental cost adjustment for Colonial that is due to adjustments to administrative and general ("A&G") expense accounts (Exh. AG-42, at 9, Sch. DJE-1, at 1).

96 This value was derived by the Attorney General, assuming that the per customer A&G expense for Colonial was also applicable to Essex (Exh. AG-42, at 12, Sch. DJE-1, at 3).

administrative and general costs that may or may not be incremental, it considered these costs incremental in nature in order to provide a conservative grouping of non-incremental costs (id.).

In the case of Essex-related costs, the Company notes that the SEC formulas do not recognize Essex as a distinct entity from Boston Gas, and thus no costs are assigned or allocated to Essex under the SEC formula (id.). However, the Company argues that it has allocated costs between itself and Essex using the same analysis as performed for Colonial (id. at 68-69).

Turning to the Attorney General's arguments about the effect Keyspan Services has on the circumstances behind the Department's decisions in D.T.E. 98-27-A or D.T.E. 98-128, the Company argues that the existence of Keyspan Services provides the Department with the exact vehicle first considered by the Department in D.T.E. 98-27, at 47, when it directed the Company to develop and file a cost allocation method that identified and allocated all Essex- and Company-related common costs (id. at 71). The Company argues that, to the extent any change in circumstances have occurred, it has resulted in the installation of a comprehensive system to explicitly track and allocate costs, and the allocation of costs that are non-incremental to Boston Gas is consistent with the requirements of the SEC, thereby warranting their recovery through the Company's cost of service in a ratemaking proceeding (Boston Gas Reply Brief at 26). Boston Gas maintains that the existence of Keyspan Services will allow the Department to make determinations regarding its incremental cost accounting orders (Boston Gas Brief at 71-72).

Concerning the Attorney General's arguments about the increase in A&G expenses since the Essex and Colonial acquisitions, the Company contends that there is no basis for the Attorney General's claim that Boston Gas must show savings as a result of the Essex and Colonial acquisitions (id. at 73; Boston Gas Reply Brief at 27). The Company states that it has analyzed all non-gas O&M expense accounts for the three-year period ending in 1998 and compared that result with the total O&M expense for 2002 (Boston Gas Brief at 72-73, citing Exhs. AG 11-1; AG 1-28; Boston Gas Reply Brief at 30-33).

Turning to the Attorney General's analysis in regarding employee benefits, the Company disputes the need to exclude non-pension employee benefits from the analysis, reasoning that these costs are not outside the Company's control and are partially recorded in Accounts 920 and 921 (Boston Gas Reply Brief at 31, citing RR-AG-101). Boston Gas maintains that, after adjusting for pension costs, total sales expense, and system maintenance expense, and without adjusting for inflation, there is only a one percent variation in the 2002 expense levels versus the Attorney General's calculated derivation of 15 percent (Boston Gas Brief at 72, citing RR-AG-101; Boston Gas Reply Brief at 32).[97] After adding the Attorney General's proposed incremental cost adjustment to the analysis, Boston Gas maintains that

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[97] In its initial brief, the Company stated that there was a variation of only four percent in 2002 O&M expense (Boston Gas Brief at 72). In its reply brief, Boston Gas conceded that uncollectible accounts could be appropriate for exclusion from the analysis, as these costs are considered somewhat outside of Boston Gas' control and are unrelated to corporate and administrative services (Boston Gas Reply Brief at 31). However, the Company claims that the Attorney General relied on an understated uncollectible expense, which when corrected indicates a variation of only one percent in 2002 expense levels (id. at 32).

there is only an eight percent variation in the 2002 expense levels (Boston Gas Reply Brief at 33). The Company contends that these analyses demonstrate that it has met even the Attorney General's own stated standard (Boston Gas Brief at 73; Boston Gas Reply Brief at 32-33).

3. Analysis and Findings

The Department must determine if the Company has followed the directives contained in D.T.E. 98-27 and D.T.E. 98-128. In order to make this determination, the Department must assess the cost-allocation method proposed by the Company in this proceeding. In addition, the Department must address whether the acquisition of Eastern Enterprises by Keyspan has a material effect on the Department's directives in D.T.E. 98-27 and D.T.E. 98-128.

In D.T.E. 98-27, at 47, the Department directed the Company to develop a cost-allocation system for transactions between Boston Gas and Essex. Similarly, in D.T.E. 98-128, at 88-89, the Department directed the Company to develop a cost-allocation system for transactions between Boston Gas and Colonial. Subsequently, Eastern Enterprises was acquired by Keyspan. In this proceeding, the Company has proposed an adjustment to its cost of service because the SEC-approved formula assigns incremental as well as some non-incremental costs to Colonial. The Attorney General argues that this cost-allocation method represents a "fundamental alteration" of earlier Department decisions. The current proceeding is the first instance since the Department's merger Orders in which the Company has had the opportunity to present a proposed cost-allocation method to the Department.

The Attorney General argues that because the Company has not incorporated merger-related savings in its cost of service, which would serve to offset increases in the Company's revenue requirement, the non-incremental costs that are included in the cost of service only serve to increase Boston Gas' revenue requirement. In D.T.E. 98-27-A at 4-5, and D.T.E. 98-128, at 88, the Department defined incremental costs as those costs that Boston Gas would not have incurred except for the need to serve Essex and Colonial. Conversely, non-incremental costs are those costs that Boston Gas would have incurred absent the mergers. Therefore, the Attorney General's assertion that the inclusion of non-incremental costs in the Company's cost of service increases Boston Gas' revenue requirement is inaccurate because, by definition, these costs would have been borne by Boston Gas ratepayers, absent the mergers.

Boston Gas has not proposed to supplant the Department's prescribed cost allocation method with a SEC-approved method, but rather to apply a SEC-approved method for accounting purposes while continuing to rely on the Department's incremental cost allocation method for ratemaking purposes during the term of Colonial's and Essex's rate plans (Exh. KEDNE/PJM-1, at 20-22). The SEC's allocation method does not address cost recovery, but leaves this issue to the utility commissions in the states in which the holding company's retail subsidiaries are located. D.T.E. 98-51, at 30. These functions remain with state commissions. Id.. The SEC may decide how Keyspan Services' costs should be allocated, but the Department must decide the reasonableness of the cost allocated to Boston Gas' ratepayers to determine whether those costs can be included in cost of service. Id.

Absent the acquisition of Eastern Enterprises by Keyspan, the Company's cost-allocation method would have depended upon whether Eastern Enterprises established a service company to allocate common costs among its affiliates. Had Eastern Enterprises decided not to form a service company, as was the case here, the Company itself would have served as the vehicle for cost allocations. Conversely, had Eastern Enterprises elected at some point to form a service company to account for the common costs associated with its utility subsidiaries, the cost allocation method would have been designed to allocate costs among all of its utility affiliates. Once Eastern Enterprises was acquired by Keyspan, the creation of Keyspan Services was consistent with both the requirement of the SEC and the Department's directives in D.T.E. 98-27 and D.T.E. 98-128 that a cost allocation method be developed. The Department has recognized the theoretical benefit that the creation of a service company can provide to ratepayers. Boston Edison Company, D.P.U./D.T.E. 97-63, at 65 (1998). Therefore, Keyspan's acquisition of Eastern Enterprises did not create a fundamental alteration to the Department's decisions in D.T.E. 98-27-A or D.T.E. 98-128, as claimed by the Attorney General, but rather served only to shift the means by which the required cost allocation would be developed from Boston Gas to Keyspan Services.

The Department has reviewed the evidence regarding the cost allocation method employed by Keyspan Services. The Department finds that the Company's cost allocation method is consistent with the SEC and the Department's directives in D.T.E. 98-27-A and D.T.E. 98-128 (Exhs. KEDNE/PJM-1, at 20-22; KEDNE/PJM-2 [supp.] at 88-96, 106-108; AG 1-28; AG 11-1).

The Company used three criteria for determining which costs allocated to Colonial and Essex constitute non-incremental costs for Boston Gas (Exh. AG 11-1). The costs that corresponded to project activity were found to be incremental to Colonial and Essex and, therefore, were allocated entirely to Colonial and Essex (Exhs. KEDNE/PJM-2 [supp.] at 88-96, 106-108; AG 11-1). In addition, the Company classified all costs related to activities such as field marketing, leak survey and meter operations as incremental to Colonial and Essex and, therefore, allocated these costs entirely to Colonial and Essex (Exhs. KEDNE/PJM-2 [supp.] at 88-96, 106-108; AG 11-1). Finally, Boston Gas allocated costs that were not directly assigned to Colonial and Essex and pertained to activities such as general and administrative activities, corporate management, finance, human resources, and legal entirely to the Company. The Department finds that these costs were non-incremental to Boston Gas and, therefore, properly allocated entirely to Boston Gas (Exhs. KEDNE/PJM-2 [supp.] at 88-96, 106-108; AG 11-1). In summary, the Department finds that the Company's method of determining incremental versus non-incremental costs pertaining to Colonial and Essex is reasonable (Exhs. KEDNE/PJM-2 [supp.] at 88-96, 106-108; AG 11-1). Accordingly, the Department accepts the Company's method for determining incremental costs (Exh. AG 11-1).

The Department has determined that the Company has properly allocated merger-related costs between Boston Gas, Colonial and Essex. The Department has also found that the Company has reasonably determined incremental costs. In addition, the Department finds that the cost of service adjustments proposed by the Company related to Colonial and Essex costs are consistent with the Department's directives in D.T.E. 98-27-A and D.T.E. 98-128.

Accordingly, the Department allows the $7,256,297 adjustment to test year cost of service for Colonial-related non-incremental costs and the $425,031 adjustment to test year cost of service related to additional Essex-related incremental costs.

The Department has adopted a ten-year PBR plan for Boston Gas. Section VIII.C.3, below. Consequently, the ten-year rate freezes for both Colonial and Essex will have expired prior to the end of the Company's PBR plan. If either Colonial or Essex seek an increase in rates pursuant to G.L. c. 164, § 94 prior to the end of the Company's PBR plan, there is a possibility that Boston Gas ratepayers would be subsidizing Colonial and Essex ratepayers because of the cost allocation approach prescribed by D.T.E. 98-27-A and D.T.E. 98-128. Therefore, in order to prevent the possibility of subsidization by the Company's ratepayers of other Keyspan operations, Keyspan is directed to submit a proposal, as part of any Colonial and Essex rate petition under G.L. c. 164, § 94 that is submitted prior to the end of Boston Gas' PBR plan, to ensure the elimination of any potential for cross-subsidization that may exist among the rates of the Company, Colonial, or Essex.

T. Entergy-Koch Contract

1. Introduction

On November 1, 2002, the Company's interim portfolio management agreement with Entergy-Koch Trading, LLP ("Entergy-Koch") took effect. This agreement was intended to replace an expiring agreement with El Paso Merchant Energy Gas, LLP, that provided the Company with a majority of its city gate gas supply requirements as well as management of certain upstream capacity, underground storage and term supply contracts (Exh. AG 1-B(1)(a),

at 3; Tr. 1, at 45-46). A contract with Entergy-Koch took effect on April 1, 2003, offering portfolio management services and gas supply for an initial term of one year, with an option for the Company to renew for two additional one-year terms (Exh. AG 17-46(a) at 16; Tr. 1, at 45-46). The Company stated that it was uncertain whether the Entergy-Koch contract was submitted to the Department for approval (Tr. 1, at 46-47).

2. Positions of the Parties

a. Attorney General

The Attorney General contends that Boston Gas has failed to seek Department approval of the Entergy-Koch contract, in violation of G.L. c. 164, § 94A (Attorney General Reply Brief at 10). The Attorney General argues that the renewal provisions of the Entergy-Koch contract transform the contract into a de facto long-term agreement, and that the Company's structuring of the contract periods constitutes an attempt by Boston Gas to circumvent the Department's statutory authority (Attorney General Brief at 3; Attorney General Reply Brief at 10, citing Exh. AG 1-2(B)(1)(a) at 3; Tr. 1, at 41-42). The Attorney General urges the Department to take this contract into consideration when evaluating the Keyspan acquisition under the Department's § 96 no net harm standard (Attorney General Reply Brief at 10).

b. Boston Gas

Boston Gas maintains that its contract with Entergy-Koch consists of two components: (1) a three-year asset management agreement; and (2) a one year-gas purchase agreement with a term that is typical for Massachusetts LDCs (Boston Gas Brief at 8). The Company contends that while it is obligated to obtain Department approval of any gas supply contract with a term

in excess of one year, there is no statutory requirement for Department approval of an asset management contract that does not involve the purchase of gas (id., citing G.L. c. 164, § 94A). Because the Company concluded that the Entergy-Koch contract does not fall within the statutory requirements of G.L. c. 164, § 94A, Boston Gas concludes that Department approval of the Entergy-Koch contract is also unnecessary (id., citing Exh. AG 17-46).

3. Analysis and Findings

Pursuant to G.L. c. 164, § 94A, LDCs must obtain the Department's approval of gas supply contracts with a term in excess of one year. In addition, the Department has stated that LDCs entering into portfolio management agreements must submit them to the Department for review and approval prior to implementation. NOI/Unbundling, D.T.E. 98-32-B at 57 (1999).

Regarding the gas supply agreement entered into between Boston Gas and Entergy-Koch, we note that it is for one year, with a provision for two one-year extensions beyond the initial one year term. Based on the above, the Department finds that Boston Gas was not required to submit this agreement, when entered into, for Department approval. However, any extension of this agreement beyond the initial one-year period will subject it to the requirements of G.L. c. 164, § 94A. Therefore, if the Company wishes to extend the Entergy-Koch agreement beyond its initial one year term, Boston Gas must seek Department approval prior to such extension.

Regarding the portfolio management agreement, when the Department required LDCs to submit all management agreements for review and approval, we did not differentiate between long and short agreements. See D.T.E. 98-32-B at 57. The Company has failed to

submit its three-year asset management agreement with Entergy-Koch for our review. Accordingly, Boston Gas is directed to submit this management agreement for Department review on or before December 15, 2003.

U. Promotional Programs

1. Introduction

During the test year, Boston Gas booked a total of $11,547,007 in promotional sales expenses, related to various furnace and boiler rebate programs for new heating customers, as well as the Company's value plus installer ("VPI") program[98] (Exhs. AG 13-19; AG 23-1).[99] This amount includes (1) $7,428,258 in direct expenses specifically related to Boston Gas' sales promotion or advertising activities (e.g., charges for furnaces provided to new heating customers, equipment rebates, and VPI program expenses), and (2) and $4,118,749 in indirect promotional expenses in the form of salaries, benefits, and overhead relating to the entire sales force whose responsibilities include overseeing the Company's promotional and advertising activities (Exh. AG 23-1).

Boston Gas calculated an internal IRR to evaluate whether the Company's promotional expense resulted in net benefits to ratepayers (Exh. DTE 4-28). Boston Gas' IRR analysis

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98 The VPI program provides appliance installation, service and repair contractors with qualified leads for gas conversions through the offer of specific benefits to participating vendors (Exhs. MOC 1-13; MOC 2-4(a)).

99 During the test year, Boston Gas incurred a total of $13,667,512 in promotional sales and advertising expenses, of which the Company seeks recovery of $13,026,308 (Exhs. MOC 1-1; MOC 1-2(a), AG 23-1; KEDNE/PJM-2 [rev. 2] at 24). Of this amount, $11,547,007 represents promotional sales expense. The remaining $2,120,505 is advertising expense, discussed in Section IV.Y, below.

compared the Company's capital investment in meters, mains, and services, and promotional expenses, to the discounted annual cash flow it projected it would receive from its investment (id.). The Company calculated the discounted annual cash flow by subtracting annual margins from O&M expenses and taxes, projected over 25 years for residential load and 15 years for C&I load, discounted at 9.5 percent (id.). The Company's calculation yielded a combined IRR of 18.83 percent for growth-related investments and promotional program expenses (id.).

2. Positions of the Parties

a. Attorney General

The Attorney General argues that Boston Gas has failed to demonstrate that its promotional programs provide a net benefit to ratepayers, and, therefore, the Department should exclude $11,547,007 in promotional expenses from the cost of service (Attorney General Brief at 50, citing D.T.E. 01-56, at 65; D.P.U. 92-210, at 103; D.P.U. 92-111, at 191-193, 201-202; D.P.U. 90-121, at 133-134; Attorney General Reply Brief at 30, citing D.T.E. 01-56, at 67).

First, the Attorney General claims that Boston Gas' IRR analysis is flawed because the Company combined its sales promotion program expense with its 2002 growth-related plant additions, rather than analyzing effectiveness of the sales promotion program on its own (Attorney General Brief at 50-51; Attorney General Reply Brief at 30). The Attorney General contends that, contrary to the clear mandate of the Department to consider the cost effectiveness of promotional expenses alone, this combined analysis does not permit consideration of whether the promotional expense provided net benefits to ratepayers (Attorney

General Brief at 51, citing D.T.E. 01-56, at 67). The Attorney General disputes the Company's claim that its growth in plant additions are linked to the money that the Company spent on overhead, installer incentive programs, or the boilers and furnace equipment that it gave to customers for free (Attorney General Reply Brief at 30-32, citing Exhs. DTE 4-27; AG 23-1; MOC 1-14). The Attorney General argues that the Company has conducted no studies to establish such a link (Attorney General Reply Brief at 30, citing Exh. MOC 2-9).

Second, the Attorney General argues that the Company did not include all of its sales promotional costs in its IRR calculation (Attorney General Brief at 50). While the Company alleges that $6,228,542 is the correct amount of direct sales promotion costs to include in its IRR analysis, the Attorney General contends that the Company has reported significantly higher amounts of test year sales promotion costs throughout the course of this investigation (Attorney General Reply Brief at 31-32, citing Exhs. MOC 1-14; DTE 4-27; Boston Gas Brief at 84). Specifically, the Attorney General argues that the Company has reported direct costs for the sales promotion program ranging from $5.9 million to $11.5 million and indirect costs of $5.3 million (Attorney General Reply Brief at 32, citing RR-AG-86). The Attorney General contends that the Company should have included the full amount of sales promotion costs totaling to $16.8 million ($11.5 million plus $5.3 million), substantially reducing the IRR (Attorney General Brief at 51; Attorney General Reply Brief at 31-32).

Third, the Attorney General contends that the Company did not analyze the cost of adding customers on the system as part of its cost-benefit analysis, as required by Department precedent (Attorney General Brief at 50-51, citing D.T.E. 01-56A at 66, n.20). As part of its

cost-benefit analysis, the Attorney General argues that the Company should have considered the effect of the increased load resulting from the sales promotion expense on service quality (e.g., the extra burdens being placed on billing systems and call centers) (Attorney General Reply Brief at 31). The Attorney General alleges that service quality tends to degrade when new demand overwhelms existing customer services, such as call centers and billing systems (id.). In addition, the Attorney General disputes the Company's assertion that its customers will benefit from the sales promotional expense during the term of the PBR plan. The Attorney General contends that ratepayers will pay more than $70 million for the sales promotional programs during the term of the PBR plan (i.e., $11.5 million times 6 years), without realizing any benefits until the PBR plan has ended and the Company has put new rates into effect (id. at 30-31).

Fourth, the Attorney General argues that the Company failed to exclude the sales promotional expenses associated with the conversion of customers from electricity to gas (Attorney General Brief at 50-52, citing Exh. MOC-3, at 2). According to the Attorney General, the Company must exclude from its cost of service those sales promotion expenses encouraging the conversion from one regulated industry (i.e., electricity) to another (i.e., gas) (Attorney General Brief at 51-52, citing G.L. c. 164, § 33A; D.P.U. 90-121, at 133-134). If the Department does allow some recovery of Boston Gas' sales promotional expenses, the Attorney General argues that Department should reduce the test year expenses by $1,120,736 to remove the additional load from electric customer conversions (Attorney General Brief

at 51-52; Attorney General Reply Brief at 33-34).[100] In response to Boston Gas' argument that these electric customers were not eligible for free equipment, the Attorney General maintains that the Company failed to show that these electric customers were not persuaded to convert to gas as a result of the Company's installer incentives or television and radio advertisements (Attorney General Reply Brief at 33).

Finally, if the Department does decide to allow some of Boston Gas' promotional expense, the Attorney General argues that the test year level of promotional expense is not representative of costs that the Company will incur during the period that the rates are in effect (id. at 32-33, citing D.T.E. 98-51, at 39). The Attorney General argues that Boston Gas' test year promotional expenses "skyrocketed" past the amount of those costs in previous years.[101] The Attorney General states that, in this case, the Department should take a five-year average of the sales promotional costs between 1998 and 2002, resulting in a representative expense of $7,691,288 (Attorney General Reply Brief at 33).

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[100] The Attorney General argues that 8.2 percent (or 1,034) of the customers who converted to gas during the test year were former electric customers (Attorney General Brief at 51-52, n.37 citing MOC 1-3, at 2). To arrive at his proposed adjustment, the Attorney General takes total advertising expense (i.e., including promotional expense) of $13,667,512 multiplied by 8.2 percent, which equals $1,120,736 (Attorney General Reply Brief at 33-34, n.25).

[101] The Attorney General claims that the Company's sales promotional expense, including advertising expense, presently included in rates is $3,632,931, versus $13.6 million booked during the test year (Attorney General Reply Brief at 33, citing Exh. MOC 1-1).

b. MOC

As an initial matter, MOC notes that Boston Gas' combined test year promotional and advertising expenses are extraordinary in magnitude, accounting for approximately 15 percent of the total rate increase in this case and representing a $9.4 million increase over the promotional expense approved in the Company's last rate case (MOC Brief at 3-4). In addition to requesting several changes to Department practices and regulations, MOC argues that the total cost of the Company's promotional expense should be removed from the cost of service (id.).

In light of the "immense scope and magnitude" of Boston Gas' promotional program, MOC urges the Department to consider the following when evaluating the program's costs: (1) the current state of the natural gas industry; (2) the effects of the program on new customers; and (3) the effects of the program on the competitive marketplace (id. at 15). MOC argues that the Department should reject Boston Gas' promotional expense because the programs encourage conversion to natural gas at a time when prices are forecast to be "extremely high compared with normal levels" (id. at 12; MOC Reply Brief at 2). MOC argues the winter of 2002 - 2003 created a "severe strain on all heating resources," leading to a decrease in natural gas supplies and an increase in natural gas prices (MOC Brief at 7-8, citing Exhs. MOC 4-1 Att.; MOC 4-2 Att.). MOC contends that high natural gas prices combined with low gas inventories are predicted to continue in the near term (id. at 7-8). MOC argues that, for natural gas, the "immediate future is grim" and that a severe winter could constrain the supply volumes needed to meet the Company's peak demand (id. at 8-11,

citing Exhs. MOC 4-1 Att. at 1; MOC 4-2 Att. at 2). Despite these ongoing price and supply concerns, MOC argues that Boston Gas intends to aggressively promote its natural gas conversion program (MOC Brief at 11, citing Exhs. MOC 1-3; MOC 2-8; RR-MOC-3). MOC alleges that the Company did not conduct any analysis to determine at what level of natural gas price increases or supply shortages it should stop promoting its conversion program (MOC Brief at 11). MOC suggests that adding more load to the Company's system could adversely affect Boston Gas' ratepayers in terms of both price and supply, and, therefore, it would be imprudent for promotional expense to be included in the cost of service (id. at 12).

In addition, MOC argues that while the Department has traditionally evaluated promotional programs on the basis of net benefits to ratepayers, the Department should now consider the whether the conversion program is beneficial for the individual customer (id. at 12, 15; MOC Reply Brief at 3). MOC argues that the Department should not allow rate recovery for programs encouraging ratepayers to convert to natural gas at a time when its price is forecast to be "extremely high compared to historic levels" (MOC Brief at 12).

MOC also argues that all costs and expenses associated with Boston Gas' promotional programs should be disallowed (id. at 14). MOC maintains that the Company's promotional programs must satisfy a two-step test to be eligible for recovery in rates (id.). First, MOC argues that the Company must satisfy a threshold burden that a particular program provides a "true direct benefit" to ratepayers (id.). If this threshold burden is met, MOC argues that the Company must then establish, through a clear cost-benefit analysis, that the program provides an economic net benefit to ratepayers (MOC Brief at 15; MOC Reply Brief at 3). MOC

asserts the Boston Gas has failed to satisfy either of these two burdens (MOC Brief at 15; MOC Reply Brief at 3).

With respect to the threshold burden, MOC argues that individual ratepayers must realize "first-hand, personal gains" in order to show a direct benefit (MOC Brief at 15). However, MOC argues that Boston Gas' free equipment program produces, at best, indirect benefits in terms of a larger customer base and an increased load, rather than direct benefits to individual ratepayers (id. at 16). MOC notes that the Company's free equipment program is not available to existing customers (e.g., free upgrades or replacements), only to prospective customers (id., citing Tr. 17, at 2254). MOC also argues that the VPI and contractor incentive programs consume administrative and management resources and expenses, without producing direct benefits for ratepayers (MOC Brief at 18-21).[102] In the absence of benefits to ratepayers, MOC argues that ratepayers should not be subsidizing contractors through monetary incentives, advertising subsidies, and free trips (id. at 21-22).

MOC also disputes the Company's contention that its promotional programs provide net benefits to ratepayers, arguing that Boston Gas' IRR calculations are insufficient to justify rate recovery of the promotional expenses (id. at 16, citing D.T.E. 01-56; D.T.E. 01-56 A (2002)). MOC faults the Company's IRR calculations because (1) all capital investments are aggregated, and (2) the useful life assumptions of 25 years for residential customers and 15 years for C&I

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[102] In Petition of Massachusetts Oilheat Council, Inc., D.T.E. 00-57 (2001), MOC first challenged the appropriateness of ratepayer funds being used to pay for the VPI program. According to MOC, the Department deferred the ratemaking treatment of the program until the Company's next rate case (MOC Brief at 19, citing D.T.E. 00-57, at 11).

customers are too long (MOC Brief at 16-17; MOC Reply Brief at 4). By aggregating all capital investments including promotional costs, MOC argues that the Company's IRR results are misleading. According to MOC, capital projects with large IRRs could mask poorer performing promotional programs (MOC Brief at 17). Also, MOC contends that the 15 and 25 year useful life terms are "inordinately long" and inconsistent with the term used by the Department to evaluate the incentive program for Berkshire in D.T.E. 01-56 (id.).

In addition to its arguments regarding the ratemaking treatment of Boston Gas' promotional programs, MOC offers several modifications to the Department's current practices and regulations. First, MOC argues that the Department should require Boston Gas to provide potential conversion customers who respond to free equipment offers and rebates of with a cost disclosure statement detailing all of the expenses associated with conversion, including an analysis of the payback period and disclosure as to the possibility of high gas prices (id. at 13, 28). Under the Company's current advertising program, MOC asserts that customers erroneously believe that natural gas conversion will cost them little or nothing (id. at 29-30). MOC asserts that disclosure of this information as part of the Company's promotional program is necessary to permit consumers to make informed decisions prior the significant financial commitment of natural gas conversion, especially because the Company plans to continue offering its free incentive program regardless of price and supply considerations (id. at 13, 29-30). Moreover, MOC contends the Company's policy of a "guarantee of satisfaction," whereby the Company will refund dissatisfied customers for the cost of the equipment and installation expense, fails to inform customers that they will not be made whole for all of their

costs (i.e., as additional equipment and installation costs for an alternative heating system) (id. at 30, citing Exh. MOC 5-12, at 2).

Second, MOC argues that the Department should amend its standards of affiliate conduct regulations at 220 C.M.R. § 12.00 et seq. to prevent Keyspan affiliates engaged in heating, ventilation, and air conditioning ("HVAC") businesses from using "Keyspan" in their name (MOC Brief at 31-37). While MOC recognizes that the Department's regulations governing affiliate conduct permits an affiliate to use of an local distribution company's name or logo, MOC contends that HVAC businesses using the name "Keyspan" enjoy an advantage in the competitive marketplace (id. at 37; MOC Reply Brief at 8). MOC argues that requiring affiliates to adopt a name that does not include the Keyspan name or logo would put the affiliate HVAC businesses on equal competitive footing with other non-affiliated businesses in Boston Gas' service territory (MOC Brief at 37; MOC Reply Brief at 8).

c. Boston Gas

Boston Gas states that, consistent with Department precedent, the Company should be allowed to recover the promotional costs associated with its marketing programs after demonstrating that its marketing programs provide a net benefit to ratepayers (Boston Gas Brief at 83, citing D.T.E. 01-56, at 67; D.P.U. 92-210, at 103 (1993); D.P.U. 92-111, at 191-193, 201-202 (1993). Contrary to the assertions of the Attorney General and MOC, Boston Gas contends that its net benefits analysis demonstrates that the Company's sales promotion program does provide net benefits to ratepayers (Boston Gas Brief at 83-90; Boston Gas Reply Brief at 58-63).

In order to demonstrate the net benefits to ratepayers resulting from its promotional programs, Boston Gas performed an IRR analysis comparing future revenues that will be generated from new customer load to direct and indirect costs incurred by the Company to attract that new load and to connect it to the system (Boston Gas Brief at 84-85, citing Exh. DTE 4-28). Boston Gas argues that it is appropriate to include all direct, indirect and incentive program costs associated with the addition of new customers to its system when calculating the IRR (Boston Gas Brief at 84-85). The Company states that its expenditures for system growth, including rate base and related program costs, resulted in an IRR of 18.8 percent, which is above the WACC allowed in its last rate case (id. at 85-87). As a result of its promotional program, Boston Gas argues that ratepayers receive a direct benefit from increased gas volumes over which fixed costs will be spread in setting rates (id. at 89). Specifically, Boston Gas argues that its ratepayers have benefitted from increased revenues over and above the Company's direct, indirect, and promotional costs and cost of capital of more than $155 million due to its growth-related investments since its last rate case (id. at 88).

The Company disputes the Attorney General's contention that it was required to perform a separate cost-benefit analysis for each promotional program (Boston Gas Reply Brief at 90). Boston Gas argues that the Attorney General distorts the Department's findings in D.T.E. 01-56, at 67 and D.T.E. 01-56 A at 16-17. According to the Company, Berkshire stands only for the limited proposition that marginal customer costs (i.e., the costs of installing the service drop and meter) must be included in the calculation of total costs and expected margins (Boston Gas Reply Brief at 60). Thus, Boston Gas contends that the Berkshire finding

does not support the Attorney General's argument that a cost-benefit analysis combining revenue-producing plant additions and sales promotional expenses is improper (id.).

Moreover, Boston Gas argues that the Department has never "mandated a per capita cost-effectiveness comparison" (Boston Gas Brief at 89, citing Attorney General Brief at 51). Boston Gas argues that it is entirely appropriate to combine promotional program costs with revenue-producing load, and that a promotional program "can only be justified" on margins that are produced through rate base investment from an "overall perspective" (Boston Gas Brief at 90). The Company asserts that the sole way to guarantee that all direct, indirect, and program costs, including the costs of new service and meters are accounted for, is to perform an IRR calculation that considers the net present value of the flow of revenues over the life of the installed measures, i.e., 25 years for residential customer and 15 years for C&I customers (id. at 89).

The Company also contends that there is no Department precedent that requires it to show that customers would not have converted to gas service in the absence of a marketing program (Boston Gas Reply Brief at 61). Further, Boston Gas claims that there is a "direct link" between its promotional activities and expense levels and growth in residential and C&I customer load addition, despite the Attorney General's assertion to the contrary (id. at 61-62).[103] Specifically, the Company maintains that 91 percent of residential load additions and

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[103] For example, the Company claims that there is a link between the start of the free burner program in 2000 and the growth in margins associated with residential and C&I load additions (Boston Gas Reply Brief at 61, citing Exhs. DTE 4-28; MOC 1-1).

69 percent of C&I load additions resulted solely from programs that were targeted by the Company's promotional program (id. at 61).

Boston Gas also takes issue with the Attorney Generals assertion that ratepayers will not see any benefits from its recovery of the promotional program expense until new rates go into effect at the time of the Company's next rate case (id. at 62-63). Rather, Boston Gas argues that it has calculated the net present value of net income associated with new customer load from 1997 to 2002, and not for the term of the PBR plan as the Attorney General claims (Boston Gas Brief at 87; Boston Gas Reply Brief at 62-63). Therefore, the Company maintains that benefits for the 1997 to 2002 period will be locked into rates in this proceeding, because the increased volumes resulting from investments in the years prior to 2002 are included in the Company's revenue requirement (Boston Gas Reply Brief at 62-63).

Boston Gas disputes the Attorney General's argument that service quality will decline as a result of increased load (id. at 63). The Company maintains that it continues to meet or exceed the Department's service quality standards (id., citing Exh. AG 22-15; Tr. 21, at 2766-2768).

The Company also disputes the Attorney General's claim that its IRR calculation is inaccurate (Boston Gas Reply Brief at 66). Specifically, the Company argues that, of the $11,547,007 in promotional costs booked to Account 912 during the test year, $6,228,542 is associated with direct sales promotional activities, and $5,318,465 is indirect expense related to administrative and overhead expenses (id.). The Company also claims that it included $6,228,542 in sales promotional expenses in its test year IRR calculation (id. at 63).

However, Boston Gas argues that it appropriately excluded the indirect sales promotion expense of $5,318,465 from its IRR calculation because the Company would have incurred these overhead labor and benefit costs even without the sales promotional programs (id. at 66). Further, Boston Gas claims that its IRR for revenue-producing investment was calculated including direct and indirect construction costs, as well as the direct costs of the Company's promotional programs (id., citing Exhs. KEDNE/PJM-9; DTE 4-27; DTE 4-28). Finally, the Company argues that even if it did include the indirect sales promotion expense of $5,318,465, the IRR would decrease only by a "small fraction" (Boston Gas Reply Brief at 66, n.35, citing Exh. DTE 4-28(a)).

Next, Boston Gas disputes the Attorney General's assertion that its test year promotional expense is not representative of the level of costs that the Company will incur during the period that the rates will be in effect (Boston Gas Reply Brief at 67). Boston Gas counters that, pursuant to Department precedent, there is a presumption that the test year level of expense is representative and thus eligible for full inclusion in cost of service (id., citing D.P.U. 1270/1414, at 33). The Company argues that the Attorney General has not rebutted the presumption that its test year level of promotional expense is representative (Boston Gas Reply Brief at 67-38). Boston Gas further asserts that the Attorney General's use of prior years' promotional expense to argue that the test year promotional expense is not representative, is not sufficient to rebut the presumption that its test year expense is representative (Boston Gas Reply Brief at 67-68). Instead, the Company argues that it intends to maintain its sales promotion activities at test year rates going forward (Boston Gas Reply

Brief at 68, citing Exhs. MOC 1-2; MOC 2-6; MOC 2-7; MOC 2-10; AG 1-17). Thus, the Company states that the Attorney General's recommendation to substitute the average of the previous five years of promotional expenses for its test year expense should be denied (Boston Gas Reply Brief at 67-68).

Finally, regarding the Attorney General's argument that the Department should reduce the Company's promotional expenses by $1,120,736 to remove the additional load for electric customer conversions, the Company contends that the customers in question were not eligible for its sales promotional program (Boston Gas Brief at 92; Boston Gas Reply Brief at 60). Rather, the Company maintains that the goal of its promotional programs is to convert low-use customers (i.e., non-heating customers) or customers located on the Company's mains but currently taking oil service (i.e., new gas conversion customers) (Boston Gas Brief at 92; Boston Gas Reply Brief at 60). Moreover, Boston Gas argues that the Attorney General's calculation of additional electric customer load should be rejected because he double-counted expenses and post-test year exclusions (Boston Gas Reply Brief at 69-70, citing Exhs. MOC 1-1; MOC 1-2(a); KEDNE/PJM-2 [rev. 2] at 24).

In response to MOC's arguments regarding the promotion of gas conversions in the current conditions, the Company states that nowhere in the Department's standard for recovery of promotional expenses is there a requirement for Boston Gas to demonstrate that the price of its product compares favorably to prices for other fuels (Boston Gas Brief at 93). In addition, Boston Gas maintains that it does not need to demonstrate "personal benefits" for customers as asserted by MOC (Boston Gas Brief at 94). According to the Company, the Department has

not prescribed the manner in which net benefits must be demonstrated (Boston Gas Brief at 94). The Company contends the fact that the Department required Berkshire to include marginal customer costs in its net benefit analysis indicates that the Department wants all new revenue-producing load to be included in the net benefit analysis (Boston Gas Brief at 94, citing D.T.E. 01-56, at 67; D.T.E. 01-56 A at 16-17).

Regarding MOC's assertion that it should provide a payback analysis to consumers that are deciding whether to switch fuel services, the Company states that it does not have information regarding all of the costs involved in the conversion. In addition, the Company argues that such analysis requires conjecture on the price of gas, which is not under the Company's control (Boston Gas Brief at 96). Further, Boston Gas notes that the Department has ruled that these matters are better addressed in other legal forums (Boston Gas Brief at 96, citing D.T.E. 00-57, at 9-10, n.6).

In response to MOC's argument that use of the Keyspan name has caused customers to be confused about the relationship between the Company and its nonregulated affiliates, Boston Gas asserts that none of MOC's examples support its claim (Boston Gas Brief at 97). Further, the Company states that the Department has found that any restrictions on a company's name and logo should be drafted narrowly (Boston Gas Brief at 98, citing Standards of Conduct, D.P.U./D.T.E. 97-96 (1998)). According to the Company, the Department came to this finding because (1) the corporate name and logo belong to shareholders, not ratepayers, (2) the corporate name and logo provide information that customers seek and value, and (3) any

customer confusion that may occur can be prevented by the use of a disclaimer (Boston Gas Brief at 98).

3. Analysis and Findings

To recover promotional expenses through base rates, a company must demonstrate that the program results in net benefits to ratepayers. D.T.E. 01-56, at 67; D.P.U. 92-111, at 193. The measurement of net benefits is dependent upon the particular ratemaking treatment to be accorded to the program. In the case where the utility seeks to include the program above-the-line for ratemaking purposes, an incremental approach is used because ratepayers would receive the benefit of any incremental profitability. D.P.U. 90-121, at 35; D.P.U. 87-122, at 20. If a utility seeks to place the program below-the-line for ratemaking purposes, a portion of common, or indirect, costs must be assigned to the program because ratepayers are supporting the cost of utility resources that are being used in part to support the program. D.P.U. 87-59, at 10. Whatever ratemaking treatment may be proposed for a promotional program, the cost analysis should appropriately include both direct and indirect expenses, so that both the economic benefits of the program and the appropriate ratemaking treatment can be determined. See D.T.E. 01-56 A at 16-17.

As an initial matter, MOC argues that in applying this standard, Department should consider the current state of the natural gas industry. MOC suggests that in times of low natural gas supply and high prices, the Department should not encourage programs that could adversely affect Boston Gas' ratepayers. The Department had expressed its reservations about the propriety of gas utility promotional programs in the wake of gas curtailments during the

1970s. Haverhill Gas Company, D.P.U. 19660, at 8 (1979); Lowell Gas Company, D.P.U. 19037/19037-A at 28 (1977). During that time, the Department excluded from cost of service promotional program expenses that could not be reasonably shown as conservation-related expenditures. D.P.U. 19037/19037-A at 28.

However, the Department is not persuaded at this time that present conditions involving high gas prices and potential supply constraints are sufficient to trigger reimposition of our previous treatment of promotional programs. The Department allows expenses for promotional measures to be recovered through base rates, if those measures collectively provide net benefits to ratepayers.[104] Commonwealth Electric Company D.P.U. 87-122, at 19-24 (1987). It is generally true that increased throughput results in increased revenues, which in turn, spread fixed costs among a company's ratepayers whenever rates are reset. We are not inclined to depart from out net benefit precedent in this proceeding. While the Department is not persuaded that Boston Gas' promotional programs, in and of themselves, are detrimental to ratepayers, the Company has the obligation to demonstrate the benefits of its promotional programs if it seeks to recover those expenses in cost of service.

Next, we turn to a number of concerns with the cost-benefit analysis conducted by the Company. Specifically, the Company (1) included growth-related capital projects in its cost-benefit analysis; (2) did not conduct promotional program-by-program cost-benefit

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[104] The Department disagrees with MOC's argument that promotional benefits must be shown for individual ratepayers. The Department has never attempted to evaluate utility programs on the basis of benefits to individual customers, and does not consider such an evaluation process to be appropriate because such an approach is inconsistent with general principles of rate design.

analyses; (3) excluded all indirect promotional expenses from its cost-benefit analysis; and (4) conducted its cost-benefit analysis only after-the-fact.

First, Boston Gas calculated its IRR by comparing total annual revenues from growth-related investments and promotional activities of $515,455,069, and total capital of $48,155,916 for promotional and growth-related activities, which yielded an IRR of 18.83 percent (Exh. DTE 4-28). As part of this analysis, the Company included all growth-related investments such as new mains or new-home constructions, in addition to promotional program expenses. By combining promotional program expenses with the cost of capital additions, and including revenues attributed to customer growth, whether or not those customers are participants in the program, the Company has made its IRR more difficult to review. See D.T.E. 01-56 A at 17, n.7,8. Boston Gas' aggregate approach of including non-promotional expenses with promotional expenses in its cost-benefit analysis obscures the cost-effectiveness of the Company's promotional measures. Under the Company's approach, increased revenues that are attributable to naturally-occurring growth in investments and plant additions are indistinguishable from any increased revenues that resulted from promotional activities. Thus, under the Company's approach, we cannot readily isolate and measure whether Boston Gas' promotional programs on their own (i.e., excluding all other growth-related investments) provide net benefits to ratepayers. Moreover, Boston Gas' aggregate approach could, in theory, allow poorer-performing programs, or programs with low IRRs, to be subsidized by programs or capital projects with high IRRs. Boston Gas' consolidated analysis hinders the ability to determine whether a disproportionate level of

Company resources is being invested into a particular promotional program, thereby rendering management unable to effectively manage the expenditures of the Company.

Second, the Company did not conduct an IRR analysis for the individual promotional programs on their own separate merits and, as such, we cannot determine whether there are net benefits associated with particular programs. Moreover, Boston Gas' consolidated analysis frustrates the ability to determine whether a disproportionate level of Company resources is being invested in a particular promotional program, thereby rendering management less easily able to determine where to shift resources into endeavors that may prove to be more beneficial to both ratepayers and shareholders. Just as the Company has represented that it relies on IRR analyses to evaluate the economics of its various growth-related capital projects, separate IRR analyses for its promotional programs are necessary and appropriate in order to determine both the economics of the program in general, and the appropriate level of resources to invest into the project.

Third, Boston Gas' IRR analysis excluded all indirect promotional expenses. The Company incurred these expenses as part of its promotional efforts and claims that they are not avoidable. However, there is nothing in the record evidence to suggest that absent the promotional programs, the Company would have incurred these costs. The Company contends that the inclusion of indirect sales promotion costs of $5,318,465 would have little effect on the results of its IRR analysis. But, as we have noted above, an IRR analysis should appropriately include both direct and indirect expenses, so that the economic benefits of the program may be

measured and the appropriate ratemaking treatment determined. D.T.E. 01-56-A at 16-17; D.T.E. 01-56, at 67.

Fourth, the Department is concerned with Boston Gas' after-the-fact cost-benefit analysis of its promotional programs. The Company calculated an IRR after the promotional programs were in operation and the test year had ended, rather than calculating the IRR before starting the program to determine if the benefits of the program would be worth the investment.[105] Without conducting a pre-program analysis, the Company had no way to determine before investing considerable sums whether the program would provide potential net benefits to ratepayers.[106] Hindsight IRR analyses are contrary to the very purpose of cost-benefit analyses, which is to assist in the decision on whether to embark on a project in the first place. An appropriate cost-benefit analysis examines whether a particular investment is prudent before a company actually begins the investment, and not as an after-the-fact measure of the investment's success. We remind companies that, when evaluating capital or other major projects, they must appropriately conduct and document all analyses conducted before an investment is undertaken, showing that the investment is prudent. After-the-fact

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[105] The Company did not offer any pre-program IRR or other cost-benefit analysis into evidence.

[106] In addition to Boston Gas' failure to demonstrate that the cost-effectiveness of its promotional programs, the Company has failed to demonstrate the reasonability of its $11.5 million expenditure during the test year associated with promotional programs. In view of the considerable increase in promotional expense from $3,637,441 during 1999 and $13,667,512 during 2002, the Company's failure to justify the almost four-fold increase in promotional expenses during this period through cost-benefit approaches is compelling evidence that the Company has failed to properly exercise management control over these expenditures.

cost-benefit analyses must be reviewed in conjunction with the before-the-fact analyses to determine the benefits of the programs. Of course, a program analyzed only after the fact may nonetheless show legitimate-cost-benefit, but such an approach is not the best of proof, nor it is especially sound management.

Boston Gas argues that no Department precedent requires it to show the net benefit of the promotional programs alone, or the net benefit of individual promotional programs. The Company argues that the Department's Berkshire decision stands only for the limited proposition that marginal customer costs must be included in the calculation of total costs and expected margins. We agree that we have not explicitly addressed the problems discussed above concerning the Company's promotional IRR analysis. In Berkshire, we disallowed the company's proposal include $325,433 in test year costs associated with the company's "customer incentive program" because "the costs associated with the [c]ompany's incentive program exceed the benefit derived from the program." D.T.E. 01-56, at 67. The basis for the disallowance was failure to meet the net benefits test – not failure to perform a cost-effectiveness analysis to support recovery of the incentive program costs." Id.[107]

The Department, however, is not inclined to completely disallow Boston Gas' promotional programs. As calculated by the Company, these programs, overall, show an IRR of 18.83 percent, which indicates net benefit to ratepayers. An 18.83 percent return suggests that winner programs have likely exceeded losers in number. Also, we find that the record

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[107] We note, however, that the analysis presented in the Berkshire case did not include growth-related investments. See D.T.E. 01-56, at 67.

does not warrant setting recovery for a beneficial program at zero, just because the Company did not provide individual program-by-program analyses.

Department policy favors system growth if it results in the lowest average costs over time. D.P.U. 88-67, at 283; D.P.U. 92-210, at 22-23. The Department will allow rate recovery of representative costs associated with a gas company's marketing or promotional programs if the evidence demonstrates (1) that existing gas customers have received net benefit from expansion of the system shown to have resulted from the marketing or promotional program and (2) expenditure at that level will likely continue, given the company's intent to continue such programs, the economic circumstances prevailing in the gas industry (as compared to competing fuels) at the time new rates are set, and the likelihood that such programs will continue to provide comparable benefits to existing ratepayers over the years or the term such new rates will be in effect. However, in future rate cases, all companies must present an IRR analysis that (1) excludes extraneous factors, such as growth-related capital projects; (2) is conducted program-by-program; (3) includes all indirect promotional expenses; and (4) is conducted on both a pre and post-implementation basis.

Having found net benefit, the Department must next addresses whether the amount booked in the test year is representative of level of promotional expense that will occur in future years. In establishing rates for companies under its jurisdiction, the Department relies on historical test year data, adjusted for known and measurable changes. D.P.U. 96-50 (Phase I) at 76. The selection of a historical twelve-month period of operating data as a basis for setting rates is intended to reflect a representative level of a company's revenues and

expenses which, when adjusted for known and measurable changes, will serve as a proxy for future operating results. Id.

In recent years, however, the Company has significantly increased its promotional expenses. Between 1999 and 2000, the Company's promotional expense increased from $2,610,503 to $7,015,195 – a 169 percent increase (Exhs. AG 1-2B(8)(c); AG 1-2B(8)(d)). Also, in 2002, the Company increased its promotion and advertising expenses to $13.6 million, a 46 percent increase over the previous year (Exhs. AG 1-2B(8)(a); AG 1-2B(8)(b)). Although Boston Gas stated its intention to continue its promotional programs at current levels, the Company has not conducted any analyses or evaluation of the effects that increases in gas prices and constraints in supply would have on the Company's promotional activities (Exhs. MOC 1-3; MOC 2-8; MOC 4-3; MOC 4-4; RR-MOC-3; Tr. 19, at 2262-2263). Because Boston Gas has not conducted any evaluation of the extent of its involvement in promotional activities, the Department can not accord significant weight to the Company's representations about its future promotional activities. Therefore, the Department finds that the test year level of promotional activities is not representative of the recurring levels of this expense. The Department finds that a more representative level of promotional expense to include in Boston Gas' rates is the average annual promotional expense since the Company's last rate case. Therefore, the Department will determine the representative level of promotional expense based on the Company's annual promotional expense for the years 1997 through 2002.

The Company's reported promotional expense for the years 1999 through 2000 include advertising expense, which has been separately considered in this Order. In order to develop a representative level of promotional expense, it is therefore necessary to exclude the advertising expense included in the promotional balance for these years. In reviewing the Company's Annual Returns to the Department for this time period, the Department notes that the Company's 2001 advertising expense booked to account 913 is $964, compared to $1,211,644 for 2000 and $2,120,505 for 2002 (Exhs. AG 1-2B(8)(a)-(h)). The Department finds that this reported expense is abnormally low, and failure to recognize this would inflate the representative level of promotional expense. To calculate a representative promotional expense level for 2001, the Department will first take the ratio of test year promotional expense, $11,547,007, to total test year promotional and advertising expense of $13,667,512, which is 84.52 percent. The Department will then multiply this ratio by the 2001 combined promotional and advertising expense of $9,290,752, yielding a 2001 promotion expense of $7,853,358. After substituting this promotional expense level for the reported 2001 expense in the computation of the six-year average, the Department finds that the average annual promotional expense during the years 1997 through 2002 was $6,345,188.

The Attorney General and MOC dispute the extent to which the Company's promotional programs foster conversions from electricity to gas, which would result in disallowance of the associated costs pursuant to G.L. c. 164, § 33A. Although the record indicates that 1,034 customers converted from electric to gas service in the test year, the Company claims that none of these customers were eligible for the Company's promotional

programs. However, program guidelines provided to contractors state that a free boiler or furnace is available to "gas customers converting from oil or electric to gas heat" (Exh. MOC 2-4, at 6). Clearly, customers who converted from electric to gas heat were eligible for offers under the Company's promotional programs. During the test year, 1,034 customers converted from electric heat to gas heat (Exh. MOC 1-3). Pursuant to G.L. c. 164, § 33A, the Department must remove both direct and indirect expenditures associated with the conversion of customers from one Department-regulated industry to another. During the four-year period from 1999 through 2002, the number of electric to gas conversions represented 6.5 percent[108] of the total conversions undertaken by the Company (Exh. MOC 1-3). Therefore, the Department will reduce the six-year average of promotional expense, calculated above, by 6.5 percent in order to remove a representative level of expenses related to the conversion of eligible customers from electric to gas heat as a result of the Company's promotional programs. This results in an allowable promotional expense level of $5,932,751. Accordingly, the Department will reduce the Company's proposed cost of service by $5,614,256.

We now turn to two additional issues raised by MOC. First, concerning Boston Gas' 15- and 25-year payback analysis, the Department considers the appropriate term to represent the life of a promotional measure, such as the life-cycle of the equipment involved in the promotional program. D.T.E. 01-56-A at 16-17. Accordingly, the Department declines to impose a predetermined payback period for a utility's promotional program.

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[108] This value is calculated as follows: (2,218/34,181) = 6.5 percent (Exh. MOC 1-3).

Turning to the MOC's proposed changes to the Department's policies and regulations, we must consider whether Boston Gas should be required to provide conversion customers with a payback analysis before to making a conversion decision. The Department has considered this issue before, ruling that a payback analysis argument was in essence an antitrust, unfair trade practice, and that this matter was "better addressed by other legal forums rather than this regulatory agency." D.T.E. 00-57, at 10. The Department, therefore, declined to review MOC's claim. MOC's argument has not changed, and there are no compelling facts in the instant case that require us to revisit this issue. Therefore, in accordance with our precedent, we again decline to review MOC's payback analysis argument, as it belongs in another, more appropriate legal forum.

Last, regarding MOC's request that Department amend our standards of conduct regulations at 220 C.M.R. § 12.00 et seq., to prevent Keyspan HVAC affiliates from using Keyspan in their names, this issue has also been addressed previously by the Department. In D.P.U./D.T.E. 97-96, at 23, the Department found the "corporate name and logo belong to shareholders, not ratepayers and, excessive restriction of their use could violate a company's First, Fifth, and Fourteenth Amendment rights" (citations omitted). The Department further found that the corporate name and logo provide information that customers value and seek; i.e., the affiliations of the companies from which they are considering buying products or services. Id. Moreover, the Department found that customer confusion resulting from the mere use of a corporate name or logo was unlikely. Id. Again, MOC has not presented any compelling arguments (or any different arguments for that matter) that would force us to

reconsider our precedent in this area. Therefore, consistent with precedent, the Department declines MOC's request to amend our standard of conduct regulations.

V. Inflation Adjustment

1. Introduction

In its initial filing, Boston Gas proposed an inflation adjustment of $2,788,709 (Exh. KEDNE/PJM-2, at 28). The Company used the gross domestic product implicit price deflator ("GDPIPD") as derived by the United States Department of Commerce, Bureau of Economic Analysis ("BEA") and the Energy Information Administration short-term energy outlook to calculate an inflation allowance of 5.25 percent (Exh. KEDNE/PJM-1, at 29). Boston Gas applied the GDPID from the midpoint of the test year to the midpoint of the rate year, which resulted in a 5.25 percent inflation factor applied to its residual O&M expenses of $53,118,261, and thus a total inflation adjustment of $2,788,709 (id.). The Company's residual O&M expense includes only those expenses separately adjusted (id.). Based on a revised residual O&M expense of $67,108,373, Boston Gas has proposed a revised inflation allowance of $3,523,190 (Exh. KEDNE/PJM-2 [rev. 2] at 28).

Boston Gas maintains that its proposed inflation adjustment has been calculated in accordance with Department precedent (Boston Gas Brief at 63). The Company also contends that it is eligible for an inflation adjustment because it has demonstrated the implementation of cost containment measures (Exh. KEDNE/PJM-1, at 49-51). No other parties commented on the Company's proposed inflation allowance.

2. Analysis and Findings

The inflation allowance recognizes that known inflationary pressures tend to affect a company's expenses in a manner that can be measured reasonably. D.T.E. 02-24/25, at 184; D.T.E. 01-56, at 71; D.T.E. 98-51, at 100; D.T.E. 96-50 (Phase I) at 112; D.P.U. 95-40, at 64. The adjustment recognizes the likely cost of providing the same level of service in the future as was provided in the test year. The Department permits utilities to increase their test year residual O&M expense by the projected GDPIPD from the midpoint of the test year to the midpoint of the rate year. D.P.U. 95-40, at 64; D.P.U. 92-250, at 97; D.P.U. 92-78, at 60. In order for the Department to allow a utility to recover an inflation adjustment, the utility must demonstrate that it has implemented cost containment measures. D.P.U. 96-50 (Phase I) at 113.

Boston Gas detailed the cost containment methods it has undertaken in recent years in both field operations and customer service (Exhs. KEDNE/JFB-1, at 10-12; KEDNE/PJM-1, at 49-51; DTE 1-25). The Company's adoption of "best practices" concepts in field operations and customer services initiatives, such as warehouse consolidations and contractor bidding processes, is evidence that Boston Gas has implemented cost containment measures for its O&M expenses (Exh. KEDNE/PJM-1, at 49-51). Accordingly, the Department finds that an inflation allowance adjustment equal to the most recent forecast of GDPIPD for the appropriate period as proposed by Boston Gas, applied to the Company's approved level of residual O&M expense, is proper in this case.

If an O&M expense has been adjusted or disallowed from ratemaking purposes, that expense is also removed in its entirety from the inflation allowance. D.T.E. 02-24/25, at 184; D.P.U. 01-50, at 19; D.P.U. 88-67 (Phase One) at 141; D.P.U. 87-122, at 82. The Department has adjusted the Company's O&M expense for officer expenses, "Above and Beyond" payments, promotional expenses, and customer guarantee payments. In addition, while Boston Gas adjusted its residual O&M expense by $641,204 for advertising expense, the Company's proposed residual O&M expense contains the remaining portion of the test year balance, totaling $1,106,675. Because the entire test year amount of any O&M expense item that has been separately adjusted for in cost of service must be eliminated from the residual O&M balance, the Department finds it appropriate to reduce the Company's residual O&M balance by the entire test year expense associated with the above expense items. Finally, in determining the O&M expense that is subject to inflation, the Department excludes all gas-related costs from test year O&M expenses. D.T.E. 02-24/25, at 186; D.T.E. 98-51, at 103; D.P.U. 96-50 (Phase I) at 113A. Therefore, the Department will exclude O&M costs recovered through the CGAC from the residual O&M balance.

Application of these adjustments to the Company's proposed residual O&M expense balance produces a revised residual O&M expense balance of $38,563,217, as set forth in Table 1, below. As shown, the inflation allowance is $1,498,621. Accordingly, the Department will reduce the Company's proposed cost of service by $2,024,569.

TABLE 1

TEST YEAR O&M EXPENSES EXCLUDING GAS		154,113,164
LESS: TEST YEAR ADJUSTMENTS		
Wages - Union	46,729,199	
Wages - Non-Union	26,105,883	
Incentive Compensation	(2,097,330)	
Dental Expense	977,514	
Health Care Expense	8,420,912	
Pensions	6,230,016	
OPEB	6,198,509	
Insurance	1,518,493	
Property Leases	2,131,861	
Postage Fees	2,423,592	
Incremental Accounting Adjustments	(7,256,297)	
Severance	(250,000)	
Costs Recovered Through CGAC	(25,588,070)	
Bad Debts	15,503,342	
Lobbying Expense	13,247	
Advertising	641,204	
Fines/Penalties	71,150	
Adjustments to Service Company Expenses	2,194,835	
FICA Taxes Included in O&M	2,553,516	
Meter Fees	483,215	
TOTAL	87,004,791	
RESIDUAL O&M EXPENSES SUBJECT TO INFLATION PER COMPANY		67,108,373
LESS: DTE ADJUSTMENTS		
Officer Expenses	158,846	
"Above and Beyond" Payments	90,494	
Promotional Expense	11,507,007	
Customer Guarantee Payments	108,125	
Advertising	1,110,675	
Costs Recovered Through CGAC	25,588,070	
DTE Subtotal	38,563,217	
Total Residual O&M Expense		28,545,156
Inflation Increase to be Applied to the Company's Residual O&M Expense		5.25%
INFLATION ALLOWANCE		1,498,621

W. Fines and Penalties

1. Introduction

Boston Gas proposes to reduce its test year cost of service by $71,150 to remove fines and penalties that the Company incurred during the test year that it considers are not appropriate for inclusion in rates pursuant to Department precedent (Exhs. KEDNE/PJM-1, at 28; KEDNE/PJM-2 [rev. 2] at 25). The fines consist of $17,803 in parking tickets directly incurred by Boston Gas and $53,347 in the Company's allocated portion of Dig-Safe fines that it paid to the Department's pipeline engineering and safety division (Exhs. KEDNE/PJM-2 [supp.] at 132-134; DTE 3-1; Tr. 17, at 2213-2214).[109]

During the test year, Boston Gas also paid to customers $108,125 in "customer guarantees" (RR-AG-87, citing Exh. AG 23-1). These customer guarantees payments consist entirely of payments made to individual customers as compensation for failure by Boston Gas to keep service appointments, as required under the service quality component of the Company's PBR plan (Tr. 23, at 3111-3112). See Service Quality Standards, D.T.E. 99-84 (June 29, 2001 Order) at 38.

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[109] Because Keyspan Services was billed directly for all Dig-Safe fines in the New England region during the test year, it allocated 68.1 percent of the total amount to Boston Gas based on a service company allocator (Exh. KEDNE/PJM-2 [supp.] at 134-135; Tr. 24, at 3345-3346). The Company stated that Keyspan Services intends to set up separate project classifications for each of its affiliates to ensure that Dig-Safe fines are directly assigned to the respective company in the future (Tr. 24, at 3347).

2. Positions of the Parties

a. Attorney General

The Attorney General argues that Boston Gas failed to disclose that it incurred an additional $51,000 in additional Dig-Safe violations (Attorney General Brief at 59, citing Exh. KEDNE/PJM-2 [supp.] at 135; August 12, 2003 letter from Robert Smallcomb, Director of the Department's Pipeline Engineering and Safety Division to the Attorney General ("August 12th Letter"); see also Attorney General Reply Brief at 41). The Attorney General contends that the $51,000 in Dig-Safe violations that are itemized in the August 12th Letter are distinct from the fines reported by Boston Gas, because none of the payment dates in the August 12th Letter match those listed by the Company (Attorney General Brief at 59, n.51, citing in Exh. KEDNE/PJM-2 [supp.] at 135). The Attorney General argues that these additional fines are readily ascertainable, specific to Boston Gas, and that the Department should assign 100 percent of these additional Dig-Safe fines to Boston Gas as a matter of public policy (Attorney General Brief at 60, citing Boston Gas Company, D.P.U. 96-50 (Phase I) at 110; D.P.U. 88-67, Phase I at 43; D.P.U. 87-228, at 18-19; Nantucket Electric Company, D.P.U. 1530, at 26 (1983)). In additions, the Attorney General requests that the Department order the Company to create separate Dig-Safe accounts to prevent similar accounting practices in the future (Attorney General Brief at 60).

b. Boston Gas

Boston Gas claims that it has complied with Department precedent by removing from cost of service $71,150 in fines and penalties incurred during the test year (Boston Gas Brief

at 62, citing Exhs. KEDNE/PJM-1, at 28; KEDNE/PJM-2, at 25; DTE 5-36, DTE 5-37; AG 1-83; AG 6-56). The Company did not submit a brief on the Attorney General's issue of additional Dig-Safe penalties, although it had the opportunity to do so.

3. Analysis and Findings

The Department has held that fines and penalties paid by utility companies should be excluded from cost of service as a matter of public policy. D.P.U. 88-67, Phase I at 143 (1988); D.P.U. 87-228, at 18-19; D.P.U. 1530, at 26. While the Company has appropriately reduced its cost of service by $71,150 to account for fines and penalties incurred during the test year (Exhs. KEDNE/PJM-1, at 28; KEDNE/PJM-2, at 25), the Attorney General maintains that the Company has overlooked an additional $51,000 in Dig-Safe fines incurred during the test year.

Concerning the additional Dig-Safe fines identified by the Attorney General, the Department has examined the information contained in the August 12 Letter.[110] A comparison of the amounts and payment dates provided in the August 12th Letter and the information provided by Boston Gas regarding fines and penalties indicates that there are actually $52,000 in Dig-Safe fines and penalties that were incurred by the Company during the test year, but not accounted for in its initial filing (RR-AG-70). While the Attorney General proposes that the entire balance be removed from cost of service, only 68.1 percent of these Dig-Safe fines and penalties were allocated to Boston Gas (Exh. KEDNE/PJM-2 [supp.] at 135; Tr. 24, at 3346).

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[110] Of the eight Dig-Safe violation proceedings cited in the August 12th Letter that were decided during 2002, one proceeding (D.T.E. 01-PL-32) involved Essex. The other seven proceedings involved Boston Gas.

Of the $52,000, Boston Gas was allocated $35,412 of these test-year Dig-Safe fines and penalties (Exh. KEDNE/PJM-2 [supp.] at 135). Therefore, the Department will reduce the Company's proposed cost of service by $35,412.

Boston Gas acknowledges that it failed to establish separate fines and penalties accounts for Boston Gas and other Keyspan affiliates in New England (Tr. 24, at 3345-3347). As a matter of public policy, fines and penalties should be directly assessed on the utility whose actions give rise to the fine or penalty, and not allocated among unaffected companies through the use of a general allocator. Accordingly, the Department directs Boston Gas to implement the necessary accounting revisions to ensure that Dig-Safe fines, as well as other fines and penalties, are directly assigned to the appropriate Keyspan affiliate.

Regarding Boston Gas' payments to customers under the customer guarantee component of its service quality plan, the evidence demonstrates that the Company's test year payments was $108,125 (RR-AG-87). As an initial matter, the Company's customer guarantee program is by its nature intended to secure performance by Boston Gas by identifying in advance the revenue consequences of delinquent performance and stipulate "damages" for delinquent performance, to be paid to individual customers for these "damages" arising from service quality failures that directly affect these customers. D.T.E. 99-84 (June 29, 2001 Order) at 36-37. See also NSTAR Electric Service Quality, D.T.E. 01-71A at 19 (2002). The point of service quality penalties is to compensate affected customers and make companies pay for substandard service in failing to keep appointments. There is neither logic nor justice in the Company's asking to pass on its penalty to all ratepayers collectively. It is surprising the

Company would even ask for so blatantly perverse a result. It is a patent waste of time to make an issue of this. Consistent with the Department's treatment of fines or penalties for ratemaking purposes, we will reduce the Company's cost of service by an additional $108,125 to account for test year customer guarantee payments. The removal of Dig-Safe fines and customer guarantees from cost of service results in a reduction to the Company's test year cost of service of $214,687. Because Boston Gas has already reduced its test year cost of service by $71,150, the Department will reduce the Company's proposed cost of service by an additional $143,537.

X. Uncollectible Expense

1. Introduction

The Department permits a representative level of uncollectible revenues (i.e., bad debt) as an expense to be included in rates. During the test year, Boston Gas booked $15,572,000 in bad debt expense (Exh. KEDNE/PJM-2, at 22). The Company proposes to calculate bad debt expense by comparing its net writeoffs in the years 2000 through 2002 to firm revenues in the same period (Exh. KEDNE/PJM-1, at 27). The resulting bad debt ratio of 1.83 percent was multiplied by normalized firm-sales revenues in the test year of $612,239,427, which yields a bad debt expense allowance of $11,203,982 (id.). The test year bad debt expense of $15,570,000 was subtracted from the bad debt expense allowance of $11,203,982, to yield a reduction to test year O&M expenses of $4,299,361 (Exh. KEDNE/PJM-2, at 22).

To account for the portion of the bad debt expense associated with production, which is collected through the gas adjustment factor ("GAF"), Boston Gas adjusted its bad debt expense

based on a ratio of gas cost revenues in the years 2000 through 2002 and total sales and transportation revenues in the same period (Exh. AG 13-33). The resulting ratio of 55.30 percent was multiplied by the bad debt expense allowance of $11,203,982, which yields the amount of bad debt relating to gas costs of $6,195,802 (id.).

2. Positions of the Parties

a. Attorney General

The Attorney General argues that the Department should reject Boston Gas' bad debt expense proposal, contending that the Company's test year bad debt amount is not representative (Attorney General Brief at 56-59). Specifically, the Attorney General states that the Company failed to include recovery amounts for the second half of the test year due to flaws with the Company's conversion to the CRIS (id. at 57, citing RR-AG-36; Tr. 8, at 965-967). The Attorney General contends that Boston Gas either could not or did not track recoveries for the third and fourth quarters of the test year, when the Company was contemporaneously converting to the CRIS (Attorney General Brief at 57).

Moreover, the Attorney General contends that there is no evidence to support the Company's assertion that net write-offs increased after reflecting recoveries for the third and fourth quarters of 2002 as compared to the previous two quarters (id.). The Attorney General, therefore, argues that Boston Gas' three-year weighted average of net write-offs is inflated, as is the allowable bad debt expenses, resulting in a reduced total bad debt expense adjustment (id.). The Attorney General argues that the Company under-reported the bad debt adjustment

to the test year residual O&M expense base, which then increased the residual O&M expenses subject to inflation, and, in turn, increased the total inflation adjustment (id.).

The Attorney General states that the Department should average the 2000 and 2001 recoveries, replace the 2002 net write-offs amount with that average, and recalculate the resulting bad debt expense adjustment (id. at 58). The Attorney General argues that this formula would increase the total bad debt adjustment by $183,671 and (using the revised weighted average percentage), reduce the uncollectible amount in the proposed rate increase (id. at 58-59).

b. Boston Gas

In response to the Attorney General's argument that the Department should revise the Company's 2002 net write-offs, Boston Gas states that although the CRIS did not report recoveries during the first few months of its operations (July through September 2002), it does have accurate records of its net write-offs for the entire test year (Boston Gas Brief at 103-104, citing Exhs. AG 1-34, at 9; AG 1-69). Accordingly, Boston Gas claims that it has supported its bad debt expense amount and therefore the Company's proposed level of bad debt expense should be approved by the Department (Boston Gas Brief at 104).

3. Analysis and Findings

The Department permits companies to include for ratemaking purposes a representative level of uncollectible revenues as an expense in cost of service. D.T.E. 02-24/25, at 168-173; D.T.E. 01-56, at 96; D.P.U. 96-50 (Phase I) at 70-71. To determine the amount of uncollectible revenues to include as an expense in cost of service, a company first calculates

the average of the most recent consecutive three years' net writeoffs, as a percentage of adjusted test year revenues for the corresponding period (i.e., the uncollectible ratio). D.T.E. 02-24/25, at 168-170; D.P.U. 01-56, at 96-97. The Department finds that the Company has correctly calculated the uncollectible ratio by using the net writeoff and firm revenue figures from 2000 through the test year 2002.

However, we now address the question of whether Boston Gas' failure to itemize recoveries during the second half of the test year has the effect of overstating the three-year average of net writeoffs, and thus renders test year net writeoffs unrepresentative. The Company books net writeoffs each month by taking the difference between writeoffs and recoveries (Exh. KEDNE/PJM-2 [supp.] at 119). According to the Company, it was not able to separately breakout recoveries for the months of July 2002 through September 2002 because of its conversion to CRIS during this time period (RR-AG-36). The amount of writeoffs the Company booked to the first half of the test year is $6,730,748, and the amount of writeoffs it booked to the second half of the test year is $10,529,780, an increase of 56 percent (Exh. KEDNE/PJM-2 [supp.] at 119). Also, the writeoffs booked in July 2002 ($3,119,386) are approximately twice the amount booked in any other month. During the second half of the test year, given (1) the significant large increase in writeoffs, (2) the inability of the Company to confirm the accuracy of its reported net recoveries, and (3) the unusually high amount of writeoffs in July 2002, the Department finds that the amounts booked to the second half of the test year are not representative and, therefore, cannot be used to calculate the allowed bad debt expense (id.). Instead, we direct the Company to calculate the uncollectible ratio by

comparing its net write-offs during calendar years 2000 through 2001 to firm revenues in the same period. In calculating the uncollectible ratio based on two years of data in this case, we are not changing our standard, instead we are merely establishing a representative amount not withstanding reporting problems associated with the conversion to CRIS.

The Department has found that allocating uncollectible expense between base rates and the GAF is necessary to account for customer migration from firm service to transportation service. D.T.E. 01-56, at 96-97; D.P.U. 96-50 (Phase I) at 72-73; D.P.U. 93-60, at 412-413. In D.T.E. 02-24/25, at 171-172, the Department stated:

> The policy underlying the method approved in D.P.U. 96-50 (Phase I) was to account for the effects of customer migration. As customers migrated to competitive supply, the Department expected that production-related bad debt would decrease because the supplier of a customer that migrated to transportation would be responsible for such customer's production-related bad debt. The intent was not to allow recovery of bad debt expense greater than the level determined to be reasonable in a rate case. Thus, our policy of allowing gas companies to collect a portion of bad debt through the GAF was not intended to allow the gas companies dollar-for-dollar recovery of production-related bad debt expenses.

Accordingly, the Department directed Fitchburg to allocate a portion of bad debt expense to the GAF based on the actual level of customer account writeoffs tracked for gas supply during the test year to the total level of writeoffs. The Department directed Fitchburg to update this factor semi-annually, in the GAF proceedings and multiply it by the level of bad debt expense approved in D.T.E. 02-24/25 to determine the amount of bad debt expense to be collected through the GAF. D.T.E. 02-24/25, at 171-172.

Boston Gas has not tracked the actual level of writeoffs that occurred during the test year (RR-DTE-94). However, the CRIS is able to track actual monthly writeoffs by gas cost

and base rates (id.). Therefore, for the purpose of determining the portion of the bad debt expense approved in this case to account for through the GAF, the Department approves the Company's proposal. Accordingly, Boston Gas shall allocate a portion of the Department approved bad debt expense to the GAF based on a ratio of gas cost revenues in the years 2000 through 2002 and total sales and transportation revenues in the same period. Consequently, 55.30 percent of the allowed bad debt expense is to be allocated to the gas costs and as such recovered through the GAF.

Further, in future GAF filings, the Company shall allocate a portion of the bad debt expense approved in this case for collection through the GAF, based on the ratio of the actual level of customer account writeoffs tracked for gas supply during the previous year to the total level of writeoffs during the same time period. D.T.E. 02-24/25, at 164. The Company shall update this ratio in each GAF filing that proceeds the date of this Order and apply it to the bad debt expense approved in this rate case. Calculating bad debt expense on the ratio of the actual level of customer account writeoffs is consistent with our findings in D.T.E. 02-24/25 and preserves a company's incentive to reduce bad debt expense, while appropriately accounting for any migration to the competitive market.

Based on these findings, the Company shall calculate its bad debt expense using $15,572,000 for the test year level of net writeoffs and an uncollectible ratio of 1.52 percent. Consequently, the allowed bad debt expense is $9,326,004, the Company's base rates shall incorporate $4,168,724, with the remaining $5,157,280 to be collected in the GAF. Therefore, the Company's test year level of writeoffs will be reduced by a total of $11,403,276

to derive the bad debt expense allowed in the base rate cost of service. The allocation to base rates shall remain fixed for the term of the PBR plan approved in this Order. The Department directs the Company to file all future cost of gas adjustment clause ("CGAC") compliance filings consistent with the allocation method specified above.

Y. Advertising

1. Introduction

During the test year, Boston Gas booked $1,751,879 in direct advertising expense (Exh. KEDNE/PJM-2, at 24). To determine the level of advertising expenses to include in the cost of service, the Company first categorized its advertising expenses into the following seven groups: (1) image; (2) informational; (3) promotional-oil/propane; (4) promotional-electric; (5) combined advertising; (6) indirect advertising; and (7) other territories[111] (Exh. KEDNE/PJM-2 [supp.] at 126-131; Tr. 1, at 80). Boston Gas then removed from its cost of service $641,204 in advertising expenses it considered were not recoverable in rates under Department precedent, consisting of Company image advertising, certain information advertising, Keyspan image advertising, and miscellaneous advertising (Exh. KEDNE/PJM-2 [rev. 2] at 24). Therefore, Boston Gas proposes to include in its cost of service $1,110,675 in advertising expense (id.).

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[111] "Other territories" refers to allocations to Boston Gas of advertising expenses incurred in other Keyspan territories that the Company removed from its proposed cost of service (Tr. 1, at 89)

2. Positions of the Parties

a. Attorney General

The Attorney General argues that the Company has miscategorized many of its advertising expenses, and in doing so has overstated its allowed advertising expenses by $670,000 (Attorney General Brief at 52-53; Attorney General Reply Brief at 34). The Attorney General contends that the Company seeks to recover advertising expenses that (1) did not benefit customers, (2) engaged in competition with other regulated products and services, (3) were primarily image-related or informational-related advertisements, (4) subsidized unregulated entities, (5) fell outside of the test year, and (6) targeted Keyspan employees only (Attorney General Brief at 53).

First, the Attorney General contends that a number of Company advertisements can not be shown to provide any benefit to ratepayers (id. at 54). For example, the Attorney General claims that a radio advertisement labeled as "Value Snobs" was never aired on the radio, and that Boston Gas concedes that ratepayers receive no benefits from advertisements that never ran (id., citing Tr. 14, at 1807; Attorney General Reply Brief at 34-35; Attorney General Reply Brief at 34-35). The Attorney General notes that the supporting invoices associated with the "Value Snobs" advertisement show only that Boston Gas paid the advertising agencies a total of $92,663 to develop a marketing campaign consisting of four advertisements, one of which was the "Value Snobs" advertisement (Attorney General Reply Brief at 34-35). However, because the "Value Snobs" never ran, the Attorney General argues that Company has failed to meet its burden of proof, and, therefore, that the Department should remove the

entire balance of supporting invoices of $92,663 from the cost of service (Attorney General Brief at 54; Attorney General Reply Brief at 34-35).

In addition to the "Value Snobs" advertisement, the Attorney General contends that the Company has failed to demonstrate any benefit to ratepayers associated with $48,212 in advertising expense, because Boston Gas failed to either provide the associated invoice or a legible copy of the invoice (Attorney General Brief at 54, citing Tr. 14, at 1818; D.P.U. 92-111, at 185; Attorney General Reply Brief at 35). The Attorney General argues that the Company has failed to demonstrate the benefit to ratepayers associated with (1) $19,380 for certain meal expenses where advertising leads were "discussed" and the cost of postage and letterhead for anticipated mailing projects, (2) $18,191 in data base mining and mailing list extractions, and (3) $93,396 in advertising agency commissions and monthly retainer fees (Attorney General Brief at 54, citing Tr. 14, at 1818).

Second, concerning advertisements involving competition with other energy sources, the Attorney General contends that the Department should remove $230,151 in expenses related to advertisements that he considers are intended to encourage consumers to choose natural gas service over electric service, as well as costs related to advertisements for gas-fired water heaters, air conditioners, pool/spa heaters, stoves, fireplaces, and patio lights (Attorney General Brief at 55; Attorney General Reply Brief at 35-36). The Attorney General maintains that even a cursory review of these advertisements demonstrates that they violate Department precedent and the provisions of G.L. c. 164, § 33A (Attorney General Brief at 55, citing D.P.U. 90-121, at 133-134; Attorney General Reply Brief at 35, citing G.L. c. 164, § 33A).

The Attorney General maintains that because these advertisements urge customers to use gas instead of electricity for uses such as heating pools and lighting stoves, and serve as self-promotion to the Company, the costs of these advertisements are not recoverable under Department precedent or G.L. c. 164, § 33A (Attorney General Reply Brief at 35-36).

Third, the Attorney General alleges that the Company has requested recovery of expenses for image-related advertisements in contravention of Department precedent (Attorney General Brief at 55, citing D.P.U. 92-111, at 184; D.P.U. 90-121, at 131). Specifically, the Attorney General contends that Boston Gas booked $173,164 in advertising expense related to charitable donations, historic renovation projects, business cards, and community developments, and that these advertisements are actually image-related (Attorney General Brief at 55, citing Exh. AG-25). Therefore, the Attorney General argues that these image-related advertisements (totaling $173,164) should be excluded from the cost of service because the Company has not demonstrated that these advertisements directly benefit Massachusetts customers (Attorney General Brief at 55).

Fourth, the Attorney General contends that Boston Gas' affiliates are being subsidized in the form of reduced advertising costs paid by the Company through its VPI program (id. at 55-56). The Attorney General states that the Department should deny recovery of $18,917 for this associated third-party advertising because the Company has not demonstrated that the VPI program provides a "direct benefit to ratepayers" (id.).

Fifth, the Attorney General contends that the Company's cost of service includes $2,300, representing advertising expense that was incurred in 2001 (id. at 56). The Attorney

General maintains that because these expenses were incurred prior to the test year, the cost of this advertising should be removed from the Company's cost of service (id., citing D.P.U. 93-60, at 57 (1993)).

Finally, the Attorney General argues that Boston Gas incurred $3,300 in expenses during the test year for advertising targeted to Company employees about converting to natural gas or upgrading existing natural gas equipment (Attorney General Brief at 56). The Attorney General asserts that the costs of this type of advertising should be excluded from the cost of service (id.).

b. MOC

MOC argues that Boston Gas failed to categorize its advertising in a manner that allows the Department and interveners to review these expenditures in an orderly and efficient manner (MOC Brief at 28, citing D.P.U. 96-50; D.P.U. 93-60; MOC Reply Brief at 5). MOC contends that the Company improperly combines expenses for recoverable and nonrecoverable advertising (MOC Reply Brief at 5). Therefore, MOC recommends that the Department limit its approval of the Company's expenses to those advertisements that are clearly covered under the statutory exemptions offered by G.L. c. 164, § 33A (MOC Brief at 28; MOC Reply Brief at 5).

MOC claims that a review of Boston Gas' advertising demonstrate that most, if not all, of the promotional advertisements used by the Company during the test year violate G.L. c. 164, § 33A restrictions on rate recovery, and considers the inclusion of other advertisements in cost of service to be "questionable" (MOC Brief at 24). MOC points to one

advertisement in the form of a residential newsletter featuring articles on natural gas conversion for swimming pools, a recipe, an invitations to baseball games, and suggestions on how to save energy in warm weather through the installation of awnings and landscaping, closing curtains, and setting air conditioning thermostats (id. at 24-25, citing Exh. AG-2, at 2-4). MOC contends that none of these items fall within the statutory exemption for advertising expenses (MOC Brief at 24-25; MOC Reply Brief at 5).

Further, MOC maintains that all expenses for advertisements directed HVAC and other contractors should be disallowed as such costs are not among the exceptions set forth in G.L. c. 164, § 33A (MOC Brief at 26, citing Exh. AG-3). MOC argues that the Company's advertising targeting contractors for new residential construction should also be excluded from cost of service because (1) they are directed at contractors, versus consumers, (2) they do not benefit ratepayers, and (3) they are not among the exceptions contained in G.L. c 164, § 33A (MOC Brief at 26-27).[112] MOC also asserts that Boston Gas' promotional advertisements directed at C&I customers entitled "other uses for natural gas energy," serve to promote natural gas in competition with electricity, and thus should also be rejected as inconsistent with G.L. c. 164, § 33A (id. at 27, citing D.P.U. 96-50, at 64).

c. Boston Gas

Boston Gas defends its advertising expense as consistent with the requirements of G.L. c. 164, § 33A and Department policy that promotional advertising must leave the target

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[112] MOC's arguments concerning the Company's VPI Program are included in Section IV.Y.b, below.

audience with the impression that a nonregulated energy source is the target of the advertisement (Boston Gas Brief at 99). The Company maintains that it has properly categorized its advertising as required by the Department (Exh. KEDNE/PJM-1, at 28).

The Company addresses several arguments raised by the Attorney General, as well as, by inference, MOC. First, the Company addresses the Attorney General's claim that the cost of the "Value Snobs" advertisement should be excluded because the advertisement was never aired (Boston Gas Brief at 100, citing Exh. AG-11, RR-54-B). The Company does not dispute that the "Value Snobs" advertisement never aired (id.). Boston Gas states, however, that the Attorney General has misconstrued the invoices, because the airtime charges listed therein actually apply to the Company's "Bathtub" advertisement (id.). The Company asserts that the development costs of the "Value Snobs" advertisement only totaled $2,717, and, therefore, only this amount should be removed from cost of service (Boston Gas Brief at 100; Boston Gas Reply Brief at 71-72).

The Company disputes the Attorney General's claims that 18 advertisements or invoices totaling $48,212 are illegible or missing, instead claiming that only 14 of the advertisements or invoices totaling approximately $9,000 are in that condition (Boston Gas Brief at 101; Boston Gas Reply Brief at 73). The Company states that one invoice and three advertisements challenged by the Attorney General (totaling approximately $39,000) are fully legible, and that the Attorney General's illegibility argument is contradicted by the record (Boston Gas Brief at 101; Boston Gas Reply Brief at 73-74).

Second, Boston Gas contends that its promotional advertising is permitted under both G.L. c. 164, § 33A and Department policy, in that utility companies are allowed to recover promotional advertisements that inform consumers of products or services that are subject to direct competition from unregulated energy sources (Boston Gas Brief at 101-102; Boston Gas Reply Brief at 74-77). The Company maintains that over half of the promotional advertising cited by the Attorney General and MOC is at least partially aimed at promoting similar uses for natural gas (Boston Gas Reply Brief at 76, citing Exh. AG 25-1). The Company argues that its advertisements promoting the use of gas fireplaces are intended to facilitate competition with providers of wood and pellet stoves, which are not regulated by the Department or other governmental agencies (Boston Gas Brief at 102, citing G.L. c. 164, § 33A; D.P.U. 92-210, at 98;, D.P.U. 92-111, at 186; Boston Gas Reply Brief at 76). Additionally, Boston Gas maintains that the purpose of its gas-fired swimming pool heater advertising is to persuade people with unheated pools to use gas heating, and is not intended to compete with electric pool heaters (Boston Gas Brief at 102; Boston Gas Reply Brief at 76, citing Tr. 17, at 2203-2205). Boston Gas argues that, at the most, these advertisements could be classified as "multi-purpose" (Boston Gas Reply Brief at 74). The Company suggests that the costs associated with this type of advertising could be allowed on a pro rata basis (id., citing D.P.U. 92-111, at 187-188). Because approximately 91 percent of the Company's customer heating system conversions during the test year were conversions from oil, versus electricity, Boston Gas contends that it should be allowed to recover at least 91 percent of the costs of the

multi-purpose promotional and informational-based advertisements (Boston Gas Reply Brief at 76-77, citing Exh. MOC 1-3).

Third, Boston Gas argues that the Attorney General's contention that costs associated with informational advertisements provide no benefit to ratepayers is unfounded (Boston Gas Brief at 101-102). The Company maintains that, under Department precedent, regulated utilities are allowed to recover costs relating to promotional advertising to the extent that such advertising informs consumers of the use of products or services that are subject to direct competition from products or services of entities not regulated by the Department or any other governmental agency (id. at 102, citing G.L. c. 164, § 33A; D.P.U. 92-210, at 98; D.P.U. 92-111, at 186; Boston Gas Reply Brief at 77). The Company maintains that these advertisements are informational in nature, to demonstrate conversions of specific institutions (e.g., the Old North Church) to natural gas heat (Boston Gas Reply Brief at 77). The Company, therefore, finds that these advertisements meet the Department's precedent and statutory provisions for inclusion in cost of service (Boston Gas Brief at 102; Boston Gas Reply Brief at 77).

3. Analysis and Findings

a. Introduction

Pursuant to G.L. c. 164, § 33A, gas or electric companies may not recover from ratepayers direct or indirect expenditures relating to promotional advertising. D.P.U. 92-210, at 98; D.P.U. 92-111-A at 8. Exempt from this provision, however, is advertising, "which informs . . . consumers of and stimulates the use of products or services which are subject to

direct competition from products or services of entities not regulated by the [D]epartment or any other governmental agency." G.L. c. 164, § 33A.

The Department has encouraged utility companies and other parties to seek cost-effective methods to review advertising expenditures. D.P.U. 96-50 (Phase I) at 64 (1996); D.P.U. 93-60, at 161-162 (1993); D.P.U. 91-106/138, at 61-62. The review effort overall is one of commanding haystacks to render up their needles. In order to facilitate the review of utility advertising, the Department has established four primary groupings: (1) image-related; (2) informational; (3) promotional; and (4) miscellaneous charges.[113] D.P.U. 96-50 (Phase I) at 64; D.P.U. 92-111, at 182-191; D.P.U. 90-121, at 130-136. The Department further separated the promotional class into the following: (1) advertising which promotes the use of gas explicitly in competition with an unregulated fuel; (2) advertising which promotes the use of gas but does not explicitly reference an unregulated fuel; and (3) advertising which promotes nonutility operations. D.P.U. 93-60, at 162. In this context, the term "explicitly" as applied to competition with an unregulated fuel means that the advertisement must leave the reader or listener with the reasonable impression that the target of the advertisement is an unregulated fuel. D.P.U. 90-121, at 133.

While the Company categorized its advertising in a manner that it considered consistent with the Department's standards, the Department and parties nevertheless spent a considerable amount of time and effort during this proceeding to identify the expense associated with

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[113] The Department recognizes the existence of additional advertising categories, such as political advertising, which is explicitly precluded from rate recovery under G.L. c. 164, § 33A, and conservation-related advertising. D.P.U. 92-210, at 99, n.56.

particular advertisements. In order to facilitate the review process, the Department directs that gas and electric companies submit as part of their initial filings their advertising expenses and advertising copy organized in a manner that allows advertising media (whether in print, scripts, or other media) to be readily linked to the direct expense associated with the specific advertisement.

The Attorney General and MOC disagree with Boston Gas on the proper classification and ratemaking treatment of a number of advertising expenses. In order to evaluate the merits of the respective positions taken by the parties, the Department has assigned the Company's advertisements at issue to the categories proposed by the intervenors, using the Department's classification system to the extent possible. As part of this evaluation, the Department has included the parties' proposed classifications.

b. Image Advertising

The Department generally denies recovery of expenses associated with image advertising and/or general public relations that seek to cultivate a favorable image of the utility in the eyes of its ratepayers. D.P.U. 92-111, at 184; D.P.U. 90-121, at 131. The Attorney General contends that $173,164 in advertising expense represents image advertising. Boston Gas argues that the disputed advertising is promotional in nature.

Among the advertisements at issue are one that describes the success of two Boston Gas customers who operate a bakery operated by natural gas, and one that details the successful conversion of the Old North Church in Boston to natural gas (Exh. AG 25-1 (63),(111)). A third advertisement describes how a new building being constructed for homeless families will

be heated with natural gas (Exh. AG 25-1(63)). Although certain elements in these advertisements would enhance the image of the Company in the community, the Department is persuaded that the purpose of these advertisements is to provide informational accounts of the benefits of natural gas in a local setting. Therefore, the Department finds that these advertisements are eligible for inclusion in the Company's cost of service.

Additionally, we have reviewed the remaining advertisements cited by the Attorney General.[114] Although certain elements in these advertisements do present a favorable image of the Company in the community, the Department is persuaded that the purpose of the advertisements is to provide actual case histories where successful conversions to natural gas have occurred (see, e.g., Exh. AG 25-1(63)). There are few industries more "local" than one that largely consists of a piped delivery system buried in the streets of a community served by its product. Advertising for such a product is bound to have a local flavor connecting the community and the provider. It is hard, consequently, to draw a bright line between product advertising by the purveyor and image advertising effects. Justice Potter Stewart famously faced the same problem in a different context. The Department finds that the advertisements cited by the Attorney General are informational on the benefits of natural gas. Accordingly, the Department declines to remove the cost of these advertisements from the Company's proposed cost of service. The mere fact that an advertisement that touts natural gas as a desirable fuel, when compared to other unregulated choices, also incidentally may burnish the

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[114] Exhibits AG 25-1(18),(63),(78),(102),(111),(112),(131).

target audience's view of the natural gas purveyor is not, per se, a disqualification for recovery.

c. Promotional - Competition with Oil

The Attorney General argues that $3,300 in advertisements targeting the Company's employees about employee benefits should be excluded from the cost of service. While the advertisements are directed towards Company employees, the purpose is to encourage employees to convert from oil heat to natural gas, and, therefore, the advertisements fall within an allowable promotional category under G.L. c. 164, § 33A (Exh. AG 25-1(28),(59),(105)). The Attorney General has offered no basis for his proposal, aside from the arbitrary criterion of the status of the target market as employees of Boston Gas. There is a tendency in effective advertising to disaggregate markets and to craft advertisements to the perceived tastes or interests of a disaggregated segment of the market. Employees are just one such segment, like any other. The Department finds no basis to disallow advertising expenses which are otherwise allowable under G.L. c. 164, § 33A, only because the target market for the advertisements are employees of the Company. Therefore, the Department denies Attorney General's proposal to exclude $3,300 associated with employee-targeted advertising from the Company's cost of service.

d. Promotional - Competing With Regulated Sources

General Laws c. 164, § 33A prohibits cost recovery for promotional advertising that encourages a consumer to switch from one Department-regulated service to another Department-regulated service. However, cost recovery is appropriate for promotional

advertising that encourages consumers to switch from an unregulated Department service (e.g., home fuel oil) to a Department-regulated service (e.g., natural gas). G.L. c. 164, § 33A. The Attorney General argues that the Department should remove $230,151 in advertising expenses that he claims compete with other regulated energy sources.

The Attorney General cites 35 advertisements whose costs should be removed from cost of service because they violate the provisions of G.L. c. 164, § 33A (Exhs. AG 20-1; AG 25-1). These include advertisements encouraging conversion to gas-fired heating, gas-fired fireplaces, and gas-fired swimming pool heaters (Tr. 1, at 108; Tr. 2, at 137-138, 145-147).[115] The Department concludes that focus of these particular advertisements is to encourage residential customers to convert from oil heating to natural gas heating, use gas-fired fireplaces as alternatives to wood- and pellet-fired fireplaces, and encourage year-round swimming pool use (Tr. 1, at 108; Tr. 2, at 137-138, 145-147). These alternative energy sources (i.e., oil, wood/pellets, and natural sunlight) are not regulated by the Department. Therefore, we find that these conversion advertisements meet the provisions of G.L. c. 164, § 33A. Accordingly, the Department denies the Attorney General's proposal to remove $230,151 from the Company's cost of service.

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[115] Exhibits AG 20-1(1),(6),(15),(18),(29),(35),(40),(45),(52),(56), and (60); AG 25-1 (17),(20),(33),(34),(35),(44),(46),(48),(50),(56),(60),(62),(65),(67),(80),(88),(99),(114),(115),(124),(132),(134), and (136); along with the "Rubber Duckie/Aquazoid" advertisements; one-fourth of exhibit AG 25-1(4),(5), and (6); and Exhibit AG 25-1(29).

e. Trade Program Advertising

The Attorney General argues that the Department should remove $18,917 for advertisements associated with Boston Gas' VPI program because they do not directly benefit ratepayers. As noted above, G.L. c. 164, § 33A denies recognition in rates of the costs of political advertising and advertising that promotes the use of the utility service, but exempts the costs of "advertising which informs . . . consumers of and stimulates the use of products or services which are subject to direct competition from products or services of entities not regulated by the Department or any other governmental agency." G.L. c. 164, § 33A; D.P.U. 90-121, at 130.

We have examined the advertisements cited by the Attorney General regarding Boston Gas' VPI program (Exhs. AG 25-1(31),(54),(55),(89)-(92), and (108-110); AG 1-73(a); Tr. 17, at 2267-2269). An examination of this evidence reveals that all but one of these advertisements are promotional in that they encourage conversion from oil to natural gas, and thus meet the statutory exception for promotional expenses contained in G.L. c. 164, § 33A (Exhs. AG 25-1(54),(55),(89)-(92),(108) through (110); AG 1-73(a); Tr. 17, at 2267-2269). The remaining advertisement informs consumers of the possibility of upgrading existing equipment or faulty heating systems, and provides for an evaluation of old heating equipment for newer and more efficient heating systems (Exh. AG 25-1(31)). The Department finds that this advertisement is informational in nature, and thereby meets the statutory exception for informational advertisements contained in G.L. c. 164, § 33A. Accordingly, the Department

denies the Attorney General's proposal to exclude $18,917 for advertisements associated with Boston Gas' VPI program from the Company's cost of service.

MOC argues that advertising that encourages builders to promote the use of natural gas in homes should be excluded from the Company's cost of service, because it is directed at contractors, versus consumers, and thus does not benefit ratepayers. MOC identifies a set of marketing support materials about the Company's energy deliver builder support program, which offers services to builders who have arranged for natural gas service at their projects (Exh. AG-4; Tr. 1, at 114). The advertisement promotes "natural gas as a clean, efficient and versatile fuel" (Exh. AG-4). The Department views this to be a general gas marketing tool that does not expressly identify any competing energy supply, but is implicitly directed at gas-on-oil competition, which is permissible under G.L. c. 164, § 33A. The Department finds no merit to MOC's's claim that the cost of this advertisement should be excluded from cost of service because it is directed at contractors. Rather, it is the purchaser of these homes, as the residential end-use consumer who will be using the gas-fired appliances, who is the ultimate target of the ad (id.).[116] We find the marketing support materials cited by MOC are promotional in character, and, therefore, meet the statutory exception for promotional expenses contained in G.L. c. 164, § 33A (id.). Accordingly, the Department denies MOC's proposal to eliminate the cost of this type of advertising from the Company's cost of service.

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[116] Once a building contractor has installed a heating plant, however fueled, into a new structure, the contractor has effectively made the choice of fuel for purchasers of these structures for years, even decades, to come. The contractor is effectively the precursor of the purchaser. There is no other way to compete for new construction load than by targeting advertising to contractors.

f. Pre-Test Year Advertising Expense

The Attorney General objects to the Company's inclusion of $2,300 in advertising expense incurred during 2001. The associated invoices demonstrate that the advertisements were actually billed before the test year (Exh. AG 25-1 (Boston Society of Architects)). Inclusion of these invoices in the cost of service would result in an advertising expense that is unrepresentative of test year advertising expenses. D.P.U. 88-135/151, at 28-29. Therefore, the Department will eliminate the cost of this advertising from the Company's cost of service, and reduce the Company's proposed advertising expense by $2,300.

g. Multi-Purpose Advertisements

MOC's claims that most, if not all, of the promotional advertisements used by the Company during the test year could be assigned to more than one of the Department's four advertising categories used to facilitate review of utility advertisements (MOC Brief at 24). However, MOC references only two specific advertisements in support of its argument (id., citing Exhs. AG-2; AG-3). The first advertisement is a residential newsletter that contains, among other information, encouragement for consumers to extend the swimming season by heating their pools with natural gas (Exh. AG-2, at 3; Tr. 1, at 108). The second advertisement is trade newsletter intended for plumbers and other HVAC service providers participating in the VPI program (Exh. AG-3; Tr. 1, at 110-111). Although there are certain non-energy-related features in these publications, particularly in the case of the residential newsletter, the types of services and information contained in both of these exhibits, when viewed in their entirety, are promotional materials covered under the exemption provided in

G.L. c. 164, § 33A.[117] The Department finds that these two sets of advertising materials are promotional in character, and meet the statutory exception for promotional expenses contained in G.L. c. 164, § 33A. Accordingly, the Department will permit their inclusion in the Company's cost of service.

MOC argues that another advertisement encourages the use of natural gas over electricity, a Department-regulated energy source and thus within the rate recovery prohibitions of G.L. c. 164, § 33A (MOC Brief at 27, citing Exh. AG-6). This advertisement indicates a target audience of C&I consumers for items such as natural gas vehicles, and the conversion of diesel-fired distributed generation equipment to natural gas (Exh. AG-6). For instance, the advertisement references how oil boilers can be shut down in the summer and replaced with gas heaters (id.). Therefore, the Department finds that this advertisement is promotional in character, and meets the statutory exception for promotional expenses contained in G.L. c. 164, § 33A. Accordingly, the Department will permit its inclusion in the Company's cost of service.

h. Cancelled/Unidentified Advertising Expense

The Attorney General opposes rate recovery of certain advertisements because the copy was illegible, or the advertising spot itself was cancelled. Regarding Boston Gas' cancelled

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[117] While articles and features about items such as recipes and Cape Cod baseball are clearly not utility-related, the Department views their inclusion in the residential newsletter as a legitimate marketing technique to encourage recipients to read the material. These supplementary or accompanying materials do not change the readily evident underlying purpose of the residential newsletter, viz., to sell gas by promoting it to homeowners and those whom homeowners may look to for advice and services.

"Value Snobs" radio commercial, the Attorney General proposes that $92,663 in advertising expense be eliminated from the Company's cost of service. Keyspan purchases radio and television advertising in blocks of time geared to the target audience for a particular campaign, is billed for the actual block of time purchased, and is credited for unused airtime (RR-AG-54-B). The $92,663 identified by the Attorney General represents charges for airtime that was associated with advertisements other than the never-run "Value Snobs" commercial (Exh. AG 25-1(4)(5)(6); Tr. 14, at 1807). Further, the invoices cited by the Attorney General apply mostly to other advertisements such as the "Bathtub" radio commercial, as well as the "Belching Baby" and "New Boiler" television commercials (RR-AG-54-B). Therefore, the Department finds that none of the airtime charges associated with the invoices relate to the "Value Snobs" commercial.

While the Attorney General has overstated the cost of the "Value Snobs" commercial, Boston Gas has also failed to substantiate its proposed reduction of $2,717 for this advertisement. Instead, the Department has applied the Attorney General's proposed 25 percent allocation factor to the net agency commission fee of $6,995, resulting in an allocation to the "Value Snobs" advertisement of $1,749 (RR-AG-54-B). Accordingly, the Department will reduce the Company's cost of service by $1,749.

Concerning missing or illegible advertising copy, the Attorney General contends that 18 ads fall into that category, while the Company claims that only 14 advertisements are

admittedly missing or illegible.[118] The Attorney General claims that the Company failed to file an invoice for one advertisement (Invoice Locator No. 137) to support recovery for this advertisement (Exh. AG 25-1 (137)). The Department can find no evidence in the record of an invoice to support the advertisement designated with Invoice Locator No. 137. Therefore, we find that this advertisement is not supported by a corroborating invoice, and therefore the costs associated with this advertisement are ineligible for recovery. Accordingly, the Department will reduce the Company's cost of service by $2,640.

With respect to an advertisement designated as Invoice Locator No. 36, the advertising copy depicts an illegible representation of the advertisement's message (Exh. AG 20-1 (36)). Indeed, there is virtually no evidence in either the invoice, or the advertisement itself, to support recovery of this advertisement. Therefore, because of a lack of supporting evidence to support recovery of this advertisement, we find that it is ineligible for cost-recovery. D.P.U. 92-111, at 185. Accordingly, the Department will reduce the Company's cost of service by $34,075.

Regarding the advertisements contained in exhibits AG 25-1 (53) and AG 25-1 (129), which the Attorney General claims are also illegible, the Department has reviewed the evidence and finds that those advertisements to be fully legible. Exhibit AG 25-1 (53) informs customers about rebate programs, targets customers who already have gas in their homes, and

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[118] The Attorney General contests 18 advertisements: Exh. AG 20-1 (3), (13), (19), (20), (21), (27), (31), (36), (41), (42), (58), (62); and Exh. AG 25-1 (53), (61), (74), (129), (130), and (137). The Company contested the Attorney General's conclusions for four advertisements: Exhs. AG 20-1 (36); AG 25-1(53), (129) and (137).

encourages these customers to expand their gas usage through products, such as gas-fired fireplaces and gas-fired garage heaters. Exhibit AG 25-1 (129) informs customers of appointments that have been scheduled with VPI vendors (e.g., customers converting from oil). Because these advertisements satisfy an exception to the restrictions placed by G.L. c. 164, § 33A (i.e., advertisements that inform consumers about products and services subject to direct competition from unregulated products or services), the Department finds that the cost of these advertisements is recoverable by the Company. Accordingly, the costs of these advertisements ($1,703 for exhibit AG 25-1(129) and $1,209 for exhibit AG 25-1), will be included in the Company's cost of service.

The Company has conceded the Attorney General's arguments about the remaining 14 advertisements that he considers either missing or illegible: exhibits AG 20-1(3), (13), (19), (20), (21), (27), (31), (41), (42), (58), (62); and exhibit AG 25-1(61), (74), (130). The Department has reviewed the documentary evidence as it concerns these advertisements, and concludes that these advertisements are indeed missing or illegible. Therefore, the Department has no basis on which to evaluate the propriety of these advertisements in the Company's cost of service pursuant to G.L. c. 164, § 33A. D.P.U. 92-111, at 185. Accordingly, the Department will exclude the cost of these advertisements, totaling $8,585, from the Company's cost of service.

i. Miscellaneous Advertising Expense

The Attorney General contests three different miscellaneous expenses that he claims did not provide benefits to ratepayers. These include (1) $19,380 in costs for meal expenses

associated with meetings where advertising leads were discussed, as well as postage and letterhead for anticipated mailing projects, (2) an additional $18,191 for database mining and mailing list extractions, and (3) $93,396 for advertising agency commissions and monthly retainer fees (Exh. AG-26; Tr. 14, at 1818).

The Attorney General has flatly mischaracterized the evidence here. Of the total expense of $19,380, only $189 was actually associated with meals. The Department will remove $189 from the Company's cost of service for these meals because reimbursement of items such as meals based on receipts permits no consideration by the Department of whether the expenses are reasonable and, therefore, recovery of these as rate case expense cannot be allowed. Postage and letterhead expenses are a naturally occurring expense that companies incur during the course of advertising and promotional campaigns (Exhs. AG 20-1 (5), (16), (17), (22), (28), (30), (44), (51), (54), (55), and (59); AG 25-1 (8)). The Department has found that fees such as these are indirect costs of advertising and are appropriately included in the Company's cost of service. D.P.U. 92-111, at 195-196. Similarly, database mining and mailing list extractions are indirect costs that companies incur in the process of implementing advertising campaigns, and therefore, are acceptable for inclusion in the Company's cost of service. Id. Likewise, advertising agency commissions and monthly retainer fees represent indirect advertising costs and are appropriately included in the Company's cost of service. Id. Accordingly, the Department will permit their inclusion in the Company's cost of service, to the extent explained below.

These advertising expenses represent indirect charges that are not related to any individual or particular advertisement. The Department has previously found that a utility may recover indirect advertising expenses based on the proportion of direct advertising expense that is recoverable in relation to the total direct adverting expense proposed for recovery. D.P.U. 92-210, at 106; D.P.U. 90-121, at 196. Because the advertising expenditures referenced above are associated both with recoverable and nonrecoverable direct advertising charges, the Department finds it appropriate to allocate them based on the proportion of total allowable advertising expenses to total advertising expenses. D.P.U. 92-111, at 195-196.

To determine the level of indirect costs to be included in Boston Gas' cost of service, the Department has subtracted the $130,967 in miscellaneous advertising expenditures from the Company's proposed advertising expense of $1,110,675, resulting in a net direct advertising expense of $979,908. Next, the Department has divided the total level of disallowable advertising expense determined above, or $68,455 by the net advertising expense of $979,908, resulting in an disallowable allocation factor of 6.99 percent. This factor, multiplied by the $130,967 in indirect charges, produces a disallowable amount of $9,155.

The sum of the disallowed net advertising expense of $68,266 and allocated portion of $9,155 results in a total disallowable advertising expense of $77,610. Boston Gas has already proposed to remove $2,717 related to what it considered the development costs associated with its "Value Snobs" commercial. Accordingly, the Department will reduce the Company's cost of service by an additional $74,893 for non-recoverable advertising expenses.

Z. Depreciation Expense

1. Introduction

During the test year, Boston Gas booked $52,397,887 in depreciation expense (Exh. KEDNE/PJM-2 [rev. 2] at 30). The Company calculated depreciation expense for cost of service purposes by applying the accrual rates approved by the Department D.P.U. 93-60 to the respective test year-end balances for its depreciable plant accounts (Exh. KEDNE/PJM-1, at 30; Tr. 24, at 3349-3350). The difference between the computed depreciation expense based on year-end plant in service and the test year depreciation expense based upon average plant in service balances was $2,435,632 (Exh. KEDNE/PJM-2 [rev. 2] at 30). Therefore, Boston Gas proposed an increase of $2,435,632 to its test year cost of service (id.).

2. Positions of the Parties

a. Attorney General

Although the Attorney General proposes a number of reductions to Boston Gas' rate base that would have corresponding effects on the Company's depreciation expense, his revenue requirement schedules include the same depreciation expense adjustment of $2,432,632 as proposed by the Company (Attorney General Reply Brief, Att. 3).

b. Boston Gas

The Company chose to rely on the depreciation accrual rates established by the Department in D.P.U. 93-60, which were based on a depreciation study performed in 1992 ("1992 Study") and submitted as part of that proceeding (Exhs. KEDNE/PJM-1, at 31; KEDNE/PJM-2 [supp.] at 158-159, DTE 9-20; Tr. 24, at 3349-3350). Boston Gas stated that

during the winter of 2002-2003, the Company had internal discussions about the need to prepare a new depreciation study as part of this proceeding, but believed that there would be insufficient retirement data on the service life of its plastic mains to warrant a material change to the results of the 1992 Study (Tr. 24, at 3352-3353, 3356-3358). The Company stated that it confirmed this initial assessment in February of 2003 as the result of conversations with its depreciation consultant who had prepared the 1992 Study (Exh. DTE 9-22; RR-DTE-98; Tr. 24, at 3354). In view of the expected minimal changes in accrual rates, and the potential that a new depreciation study might actually indicate a need for higher accrual rates, the Company concluded that the costs and efforts associated with preparing a new depreciation study were unwarranted (RR-DTE-98).[119]

3. Analysis and Findings

a. Introduction

Depreciation expense allows a company to recover its capital investments in a timely and equitable fashion over the service lives of the investments. D.P.U. 96-50 (Phase I) at 104; D.P.U. 84-135, at 23; D.P.U. 1350, at 97; D.T.E. 98-51, at 75. Depreciation studies rely not only on statistical analysis but also on the judgment and expertise of the preparer. The Department has held that when a witness reaches a conclusion about a depreciation study which is at variance with that witness's engineering and statistical analysis, the Department will not accept such a conclusion absent sufficient justification on the record for such a departure.

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[119] The Company stated that a new depreciation study would cost approximately $40,000 and take about 15 weeks to complete (Exh. DTE 9-25).

D.P.U. 92-250, at 64; D.P.U. 89-114/90-331/91-80 Phase One at 54-55; D.P.U. 88-135/151, at 37; D.T.E. 01-56, at 93. It is also necessary to go beyond the numbers presented in a depreciation study and consider the underlying physical assets. D.P.U. 92-250, at 64; Berkshire Gas Company, D.P.U. 905, at 13-15 (1982); Massachusetts Electric Company, D.P.U. 200, at 21 (1980).

b. Application of 1993 Study

The decision as to whether or not a company's depreciation accrual rates are appropriate rests, by and large, with a utility's management.[120] D.P.U. 87-122, at 7; see also D.P.U. 94-50, at 265. Absent a showing that management actions are unreasonable or imprudent, the Department will not intercede in management decisions to apply particular accrual rates. D.P.U. 87-122, at 7; cf. Wannacomet Water Company, D.P.U. 13525 (1962) (company continued to use inadequate accrual rates despite significant deficiency in depreciation reserve). Moreover, in recent years, the Department has spoken to efforts to reduce rate case expense and to ensure that those expenses are incurred in a manner that is cost beneficial to the ratepayer. D.T.E. 02-24/25, at 55; D.T.E. 98-51, at 16.

Despite the fact that the 1992 Study relied upon by Boston Gas was conducted in 1993, the Company has demonstrated in this case that it reviewed the depreciation accrual rates approved in D.P.U. 93-60, made appropriate inquiries into whether revised accrual rates were

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[120] A formal depreciation study which empirically ascertains the depreciation accrual rates and retirement histories of assets for a company is not necessarily required as part of a rate case filing. Regulations Governing the Filing of Requests for Rate Relief by Gas, Electric and Telephone Companies, D.P.U. 19019-A (1976).

necessary and cost-effective, and elected not to prepare a new depreciation study (Exhs. DTE 9-22; DTE 9-25; RR-DTE-98; Tr. 24, at 3350-3358). A significant factor in the Company's decision not to conduct a new study was the lack of sufficient retirement data on plastic mains, that Boston Gas first began installing in 1971, to develop meaningful accrual rates (Tr. 24, at 3352-3353; RR-DTE-97). Based on this information, the Department finds that Boston Gas acted appropriately in evaluating its depreciation policy. See Boston Edison Company, D.P.U. 1720, at 43 (1984).

Contrary to the Company's inference, the Department did not consider average service lives ("ASLs") for cast iron, bare steel and plastic mains to be identical in D.P.U. 93-60. Rather, the Department approved an 82-year composite average ASL for mains because there was insufficient retirement data available to determine a separate ASL for plastic mains. D.P.U. 93-60, at 185. In doing so, the Department explicitly recognized that plastic mains may be expected to have an inherently longer life than mains constructed from other materials. D.P.U. 93-60, at 185. Because the ongoing retirement of old cast-iron mains in favor of plastic mains would be expected to increase the remaining service life, and therefore increase the ASL, of the distribution mains accounts, the Department has recognized that the continued use of a composite ASL may no longer provide a reliable indication of the actual service lives of newer mains. D.T.E. 02-24/25, at 134, n.62; D.T.E. 01-56, at 95. Therefore, the Department directs Boston Gas to submit a gas main material analysis, along with proposed material-specific accrual rates, as part of its next depreciation study to be filed as part of its first § 94 proceeding filed after the conclusion of its PBR term.

Turning to the merits of the Company's proposed accrual rates, the Department has previously accepted the use of the 1992 Study with modifications to Accounts 367 (Mains), and 360 (Land Rights). D.P.U. 93-60, at 183-189. Boston Gas has incorporated the Department's findings from D.P.U. 93-60 into the accrual rates developed in the 1992 Study (Exhs. KEDNE/PJM-1, at 30; KEDNE/PJM-2; KEDNE/PJM-2 [supp.] at 158-159; DTE 9-20; Tr. 24, at 3349-3350). Therefore, the Department finds that the Company's proposed accrual rates are appropriate. The Department expects that the Company will continue to review its accrual rates during the term of the PBR plan, and take appropriate measures if future events demonstrate that the accrual rates in use here no longer provide for timely and appropriate recovery of Boston Gas' capital costs.

c. Conclusion

In order to calculate the Company's annual depreciation expense, the Department has applied the depreciation accrual rates as determined above to the Company's respective test year-end depreciable plant in service balances. The Department has excluded from Boston Gas' proposed rate base $3,744533 in revenue-producing distribution mains where the Company was unable to prove the prudence of either the particular project or cost overruns associated with any of the projects, as well as the $488,444 cost overrun associated with the West Roxbury project, for a total of $4,247,082. Sections III.B and III.C, above. The cost of all of this plant has been booked to Account 367 (Mains). Consistent with this ratemaking treatment, a corresponding reduction to depreciation expense is necessary. D.T.E. 02-24/25, at 146; D.P.U. 88-67 (Phase I) at 160-161.

In order to determine the appropriate depreciation expense for Account 367, the Department has excluded $4,232,977 from the Company's year-end plant Account 367 balance of $528,247,788, producing a revised gross plant balance of $524,014,811 for this account (Exh. KEDNE/PJM-2 [supp.] at 158). Application of the 2.49 percent accrual rate to the revised Account 367 balance produces a depreciation expense of $13,047,970 for this account, rather than the Company's proposed expense of $13,153,370 (id.). Because the Department accepts Boston Gas' proposed accrual accounts and plant balances, we find that the Company's annual depreciation expense is $54,728,118, rather than the proposed $54,833,519. Accordingly, the Company's proposed cost of service will be reduced by $105,401.

AA. Amortization Expense

1. Introduction

During the test year, the Company booked $3,804,972 in amortization expense associated with leasehold improvements, the CRIS, and other computer software (Exh. KEDNE/PJM-2 [rev. 2] at 31). The Company proposes to increase its test year cost of service by $1,395,056, consisting of the following two components: (1) an increase of $1,412,398 in amortization expense, representing the difference between computing amortization expense based upon test-year-end versus test-year-average property in service; and (2) a net decrease of $17,342 in amortization expense allocated to Colonial and Essex (Exh. KEDNE/PJM-1, at 31-32; KEDNE/PJM-2 [rev. 2] at 31).

The Company's leasehold and information system amortization adjustments consist of the following: (1) an increase of $21,768[121] associated with the amortization of leasehold expenses at the Company's Rivermoor, Lynn, and Salem facilities; (9) a reduction of $11,952 in leasehold improvements associated with Waltham and the terminated Beacon Street lease; (3) an increase of $1,180,803 in CSS amortization; and (4) an increase of $222,049 in other computer software expense (Exhs. KEDNE/PJM-2 [rev. 2] at 31; KEDNE/PJM-2 [supp.] at 170). In addition to these adjustments, Boston Gas reduced its amortization expense by $179,482 representing CSS-related costs attributable to Essex and considered by the Company to be incremental in nature, and increased its software amortization expense by $162,140 representing software costs allocated to Colonial under the SEC-required allocation formula, but not considered incremental costs for Boston Gas (Exh. KEDNE/PJM-1, at 32). Therefore, the net adjustment for amortization expense is $1,395,056 (id. at 31-32; Exh. KEDNE/PJM-2 [rev. 2] at 31).

2. Positions of the Parties

a. Attorney General

The Attorney General notes that nine of the Company's computer software packages, with a total test year amortization of $421,000, are expected to be fully amortized by June 30, 2004 (Attorney General Brief at 32-33, citing Exh. KEDNE/PJM-2 [supp.] at 164; RR-AG-28). The Attorney General argues that the Department only permits recovery of

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[121] This amount includes $22, which the Company included in its proposed adjustment, that was intended to reverse an entry that had been booked twice during 2001 (Exh. KEDNE/PJM-2 [supp.] at 170).

expenses related to unamortized intangible plant remaining at the time of the Department's Order, and not on the full annualized balance (Attorney General Brief at 32, citing D.P.U. 96-50 (Phase I) at 100-101).

Because the Company intends to amortize an additional $266,000 by the date of the Department's Order, the Attorney General contends that if the Department uses the full amortization in this proceeding, Boston Gas will have a reserve for future amortizations that will continue throughout the term of any PBR plan adopted in this proceeding (Attorney General Brief at 33). Therefore, the Attorney General proposes that the Department only allow Boston Gas an amortization expense of $155,000, to be spread over the term of any PBR plan adopted in this proceeding (id.; Attorney General Reply Brief at 25, citing D.P.U. 87-260, at 75). The Attorney General reasons that his proposed reduction to the Company's proposed cost of service of $288,813 will spread the Company's expense more efficiently and better adhere to the principle behind the Department's ratemaking treatment of amortization expense (Attorney General Brief at 33, n.26).

b. Boston Gas

Boston Gas contends that it has properly accounted for its intangible plant amortization expense (Boston Gas Brief at 33-34). The Company argues that the Attorney General's claims regarding the Company's software packages are erroneous (Boston Gas Reply Brief at 47). First, the Company maintains that the Attorney General has misstated the Department's ratemaking standards on amortization, in that test year expenses are eligible for full inclusion in cost of service unless the record supports a finding that the expense level is abnormal

(Boston Gas Reply Brief at 47-48, citing D.P.U. 1270/1414, at 33). The Company maintains that the fact that these particular software amortizations will end in July 2004 is insufficient to overcome the presumption of the reasonableness of the test year expense (Boston Gas Reply Brief at 48).

Second, the Company contends that there is no Department requirement to show that a particular amortization item is non-recurring, but rather that the expense is recurring (id.). The Company reasons that, because it has capitalized software additions each year, there is sufficient evidence to establish the representative level and recurring nature of its software amortization expense (id., citing Exh. KEDNE/PJM-2 [supp.] at 164-167).

3. Analysis and Finding

The Department has found that software costs are a routine and continuing part of a company's business, and that these expenses are recurring in nature. D.P.U. 92-111, at 67; D.P.U. 89-114/90-331/91-80 Phase One at 152-153. At the same time, the Department will adjust test year expense levels for known and measurable changes to the test year. D.P.U. 87-260, at 75; D.P.U. 1270/1414, at 33.

The Department has reviewed the contested software programs. Of the nine programs, the BMS-Self Balancing program was fully amortized during 2003, and the remaining eight packages will be fully amortized by mid-2004 (Exh. KEDNE/PJM-2 [supp.] at 164). However, the Company has capitalized software additions every year, with amortizations of new software packages replacing amortizations that have been completed (Exh. KEDNE/PJM [supp.] at 164-167). There is no basis to conclude that this practice will not continue in 2003

and future years, nor that the test year amortization expense is unrepresentative of the level of costs that will be incurred in the future. Accordingly, the Department finds that no adjustment to test year amortization expense is warranted.

Concerning the appropriate amortization period for the Company's software, the Department recognizes that technological improvements may render information systems obsolete after a relatively short period of time. An excessive amortization period would tend to discourage utilities from innovations that can improve service to their ratepayers. At the same time, it is reasonable to expect that a utility's information systems should remain in service for some years after inception and benefit future customers. Therefore, an unduly short amortization is inappropriate because it shifts a disproportionate amount of the costs of these projects to current customers. D.T.E. 02-24/25, at 153; Boston Gas Company, D.P.U. 93-60-D at 4 (1994).

The Company's various software packages have differing lives, based on the individual application (Exh. KEDNE/PJM-2 [supp.] at 167). While the Department has based certain amortization periods on the PBR term established in this Order, Boston Gas' various software packages are normal capital projects with various useful lives that are independent of the Company's PBR mechanism, and thereby warrant the use of amortization periods independent of the term of the Company's PBR mechanism. Cf. D.T.E. 01-56-A at 31 (excess deferred income tax flowback linked to PBR term); D.T.E. 01-56, at 36, 77 (deferred farm discount amortization and rate case expense normalization linked to PBR term). The Department finds that the amortization periods selected by Boston Gas strike an appropriate balance between the

need to continue improvements in service technology and the need to maintain intergenerational equity. D.T.E. 02-24/25, at 153; D.P.U. 95-40, at 63. Therefore, the Department accepts the Company's proposed software amortization periods.

Concerning the Company's proposed amortization related to the CRIS, the Department has excluded $230,131 of the Company's investment in the CRIS from rate base. Section III.D. 3, above. Therefore, we find that a corresponding reduction to the Company's amortization expense is appropriate. D.P.U. 93-60, at 35. In determining the appropriate reduction to Boston Gas' amortization expense associated with the CRIS, the Company has proposed a ten-year amortization of its CRIS investment (Exh. KEDNE/PJM-1, at 46). This amortization period is identical to the ten-year amortization period the Department allowed for the Company's CSS investment in D.P.U. 93-60, and strikes an appropriate balance between the need to continue improvements in service technology and the need to maintain intergenerational equity. D.P.U. 93-60-D at 4. Therefore, the Department accepts the Company's proposed amortization period for its CRIS. The amortization expense associated with the disallowed portion of the CRIS is $23,013 (Exhs. KEDNE/PJM-2 [rev. 2] at 31; KEDNE/PJM-2 [supp.] at 168). Accordingly, the Department will reduce Boston Gas' proposed amortization expense by $23,013.

BB. Pension Expense

1. Introduction

On January 28, 2003, the Department approved a request by Boston Gas for an accounting ruling permitting it to implement the following accounting practices until otherwise

ordered by the Department: (1) the deferral and recording as a regulatory asset or liability of the difference between the level of the pension expense that is included in rates and the amount that must be booked in accordance with Statement of Financial Accounting Standards ("SFAS") No. 87;[122] and (2) the deferral as a regulatory asset of the amount of Boston Gas' current and future additional minimum liability for pensions to permit it to recover in rates over time its actual pension liability. Boston Gas Company, D.T.E. 03-1 (2003). The Company's request dealt only with pension costs because the Company currently reconciles its annual post-retirement benefits other than pensions ("PBOP") expense with the amount collected in rates and records any differences in a deferral account (Exh. KEDNE/JFB-1, at 37). Our approval of the Company's deferral request allowed the Company to avoid a potentially substantial charge against its equity.[123] At the time the Department approved the Company's deferral request, we specifically noted in our transmittal letter to the Attorney General that we had not determined the mechanism for establishing the amount of pension costs that would be included in rates.

2. Boston Gas Proposal

In this proceeding, Boston Gas proposes a mechanism for the recovery of its pension expense (Exh. KEDNE/JFB-1, at 28). Boston Gas proposes to (1) increase the amount it

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[122] SFAS 87 sets forth the accounting standards that govern the manner in which companies account for their obligations relating to employee pensions.

[123] The Company was able to avoid the recording of a regulatory asset for the additional minimum liability in 2002 by using the over-funding in the pension plan of one of Keyspan's subsidiaries, BUG, to offset the under-funding of the Boston Gas pension plan (Tr. 13, at 1702-1703).

included in cost of service for pension costs by approximately $11.86 million,[124] (2) compare the amount it included in cost of service with the SFAS 87-determined pension expense and reconcile any over-collection or under-collection, (3) assess carrying charges[125] on its prefunded pension amount and its pension deferral, and (4) amortize, over a ten-year period, the $44 million remaining balance of the PBOP transition obligation on its books as of December 31, 2002 (Exh. KEDNE/JFB-1, at 43-44; Tr. 13, at 1687).

3. Position of the Parties

a. Attorney General

The Attorney General argues that the Department should reject the Company's proposal regarding its pension obligations for several reasons (Attorney General Brief at 48). First, the Attorney General argues that the Company has not shown that the reconciling mechanism is necessary (id. at 45-47). The Attorney General states that the Company has not provided any evidence that pension costs are volatile or any evidence that the magnitude of changes in pension costs relate to the Company's overall revenue requirements (id. at 46). Further, the Attorney General states that the Department's practice of permitting recovery of reasonable and prudent pension costs through cost of service provides the Company reasonable assurance that the Department will establish rates that are adequate to recover pension costs (id. at 46).

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124 The $11.86 million represents the difference between the Company's average three-year (2000-2002) contribution of $18.2 million to its pension plan and the SFAS 87 pension expense recorded during the test year of approximately $6 million (Exh. KEDNE/JFB-1, at 39).

125 The Company seeks to recover financing costs that it incurs to fund its pension plan and PBOP plan, excluding the PBOP transition obligation (Exh. KEDNE/JFB-1, at 40).

This, in turn, according to the Attorney General, allows the Company to avoid any financial impairment due to compliance with the requirements of SFAS No. 71 (id. at 46).

Second, the Attorney General states that the Company should not receive its requested increase in pension costs because it is excessive (id. at 41). The Attorney General explains that, although the Company contributed $19,000,000 in 2001 and $44,460,000 in 2002, the Company contributed zero to the pension fund during the years 1997 through 2000 (id. at 41, citing Exh. AG-42, at 14). The Attorney General recommends reducing the Company's proposed pension expense by $7,234,000, the difference, after capitalization, between computing average contributions to the pension plan based upon a five-year versus a three-year average (id. at 43).

Third, the Attorney General argues that the Company should not receive carrying charges because such recovery is inconsistent with Department precedent (id. at 47 citing Exh. AG-42, at 20.). The Attorney General argues that allowing recovery of carrying charges on the prepaid balance in the reconciliation mechanism would be inconsistent with the Department precedent of not including pension prepaid balances in rate base (id.).[126]

b. Boston Gas

The Company claims that its proposed reconciling mechanism brings into balance the amount of pension costs being collected in rates and the Company's pension expense reported for accounting purposes (Boston Gas Brief at 198). The Company identifies several factors

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[126] The Attorney General also argues that if the reconciling mechanism is approved, the Department should lower the Company's ROE (Attorney General Brief at 93, n.63). This argument is addressed in Section.V.C.4, above.

that the Department considers in determining whether an expense category should be recovered as part of a reconciling mechanism: (1) the financial effect of the expense on the company; (2) the degree to which the Company has the ability to control the cost category; and, (3) whether approval of a separate adjustment clause will avoid an otherwise unnecessary general rate proceeding (id. at 197). The Company argues that the record demonstrates that the pension expense recognized by the Company results from a calculation that is prescribed by accounting requirements (id. at 197). The Company also claims that the record establishes the magnitude[127] and volatility[128] of the level of pension expense and funding (id. at 197-198). The Company concludes by stating that the reconciling mechanism will ease the impact of the volatility of pension expense for the Company and its customers (id. at 198). Rather than large and "permanent" changes in cost-recovery established through general rate cases, the amortization of the difference between the SFAS-determined expense and the amount being collected in rates systematically phases-in rate changes annually (id.).

The Company states that its request to increase the amount it includes annually in base rates for pension costs represents the average of the Company's actual cash contributions for the three-year period 2000 through 2002 (id. at 77-78). The Company argues that its most recent cash contributions to its pension fund are more representative of the Company's

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[127] The Company states that the proposed pension increase accounts for approximately 27 percent of the Company's revenue deficiency (Tr. 13, at 1676).

[128] The Company states that the Company's pension expense has varied significantly over relatively short periods of time (Tr. 13, at 1676-1677).

contributions than an average of the past five years because of the fundamental change in the returns previously earned by the plan in the markets (id. at 79).

Regarding carrying charges, the Company states it is simply seeking compensation for itself and customers for the time-value of money relating to the collection and payment of the pension expenses (id. at 199). In support of this compensation, the Company cites the Department's encouragement of prepayments of pension expenses and Department precedent allowing deferral of PBOP expenses with carrying charges, for recovery consideration in a later proceeding (id. at 200-201, citing Cambridge Electric Light Company, D.P.U. 92-250, at 54 (1993)).

4. Analysis and Findings

a. Introduction

The Department has not endorsed a specific method for the calculation of pension expense for ratemaking purposes but has always sought only to include an amount that allows for just and reasonable rates. See, e.g., D.P.U. 96-50 (Phase I) at 81; D.P.U. 89-81, at 33-34. Our precedent has been that the determination as to what is reasonable for each electric and gas distribution company will be conducted on a case-by-case basis. See D.P.U. 96-50 (Phase I) at 81.

In the Company's last rate case, the Department allowed pension cost recovery for ratemaking purposes based on the five-year historical average of cash contributions to the Company's pension plan. Id. at 81-82; D.P.U. 96-50-C at 42. Prior to the Department's order in D.T.E. 03-1, this approach was reasonable in large part because the Company did not

record deferrals for differences between pension expense pursuant to SFAS 87 and the amount collected in rates.

In D.T.E. 03-1, the Department authorized the Company to record a pension deferral based on the difference between pension expense determined by SFAS 87 and the amount collected in rates in order for the Company to avoid a potentially substantial charge against its equity in 2002. In order for the Company to continue to record these deferrals on a going-forward basis, however, SFAS 71 requires that the Company's regulatory deferrals be "probable of recovery" within a reasonable period (Tr. 22, at 3029). The Company defines the reasonable period as no greater than five years to meet the requirements of SFAS 71 (id.).[129]

The Attorney General states that the Company's current cash contribution method of recovering pension costs provides the Company reasonable assurance that the Department will establish rates that are adequate to recover pension costs and this approach, therefore, meets the requirements of SFAS 71 (Attorney General Brief at 46). The Company's cash contribution method of pension cost recovery approved in D.P.U. 96-50 (Phase I), however, does not provide a date certain by which costs deferred will be recovered. Unless we change the current method of recovery for pension costs to one that permits recovery of regulatory (pension) deferrals over a defined period, the Company, and ultimately customers, may be subject to potentially harmful financial consequences, stemming from potential SFAS 71

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[129] SFAS 71 sets forth the specific criteria that must be met for a regulated company to establish a regulatory asset.

write-offs during the ten-year PBR term, which is established in Section VIII.C.3 of this Order. The Company's proposal regarding a reconciling mechanism provides for probable recovery of regulatory deferrals over a time certain, and therefore meets the requirements of SFAS 71. As a result of these considerations, the Department concludes that consideration of a new approach is needed for pension cost recovery and therefore, we will consider the Company's proposal.

b. Reconciling Mechanism

The Company currently reconciles its annual PBOP expense with the amount collected in rates and records differences in a deferral account (Exh. KEDNE/JFB-1, at 37). The Company proposes to treat pension expense similarly (id. at 37-38). The Company would compare its SFAS 87-determined pension expense with the amount collected in rates, deferring the difference (id. at 39-40).

SFAS 71, however, specifies that there must be an assurance that pension costs deferred are probable of recovery. The Company proposes to recover its pension deferral, therefore, through the proposed reconciling mechanism over three years (id. at 40).

Although the Attorney General argues that he Company does not need the reconciling mechanism and that it is inconsistent with our precedent, we are persuaded otherwise. First, the Company must recover its pension deferral within a reasonable period of time to comply with the requirements of SFAS 71 and avoid detrimental financial consequences (Tr. 22, at 3029). The Company's proposal for a reconciliation mechanism accomplishes this result as

well as assures ratepayers that they pay no more and no less than the Company's costs (Exh. KEDNE/JFB-1, at 38-39).

Second, the Company has established the presence of all factors that we have considered in the past in determining that an item should be recovered through a reconciling mechanism. That is, the Company has established the following: the magnitude and volatility of pension expense; the role of accounting requirements rather than Company's actions in the pension expense volatility; and, as stated above, the effectiveness of the reconciling mechanism in avoiding the negative effects of the pension expense volatility (Exh. KEDNE/JFB-1, at 30-34; Tr. 13, at 1676-1677).

Having found that the Company needs the reconciling mechanism and that it is consistent with our precedent, we will allow the Company to implement its proposed pension reconciliation mechanism, as modified by this Order. This mechanism is an extension of the Company's policy to reconcile the annual PBOP expense pursuant to the requirements of SFAS 106 with the amount allowed in rates, which the Company did not propose to change (Exh. KEDNE/JFB-1, at 37).[130]

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[130] SFAS 106, effective 1993, established accounting standards regarding the manner in which companies account for their obligations relating to PBOP. Although precedent sets general rules to guide all companies, each company operates in its own circumstances with its own peculiar features. The Company's PBOP expense treatment has a history that we see no reason to depart from at this time. Thus, even though in D.T.E. 03-47, at 30-33, we included PBOP in a reconciling mechanism, there is no presently compelling reason to do so here for this petitioner. In any event, as discussed in this Order, the financial effect is the same in both cases.

The Company's proposal includes a request to include in rates $18,085,435, which represents the non-capitalized portion of the average of pension plan contributions for the three-year period 2000 through 2002 (id. at 39). The Department finds that because a reconciling mechanism allows the Company to recover its annual pension expense over a three-year amortization period, establishing rates based on actual contributions is no longer appropriate. Moreover, the requested pension-cost recovery based on the three-year historical average contributions approach of $18,085,435 exceeds both the test year SFAS 87-determined pension expense of $6,230,016 and the projected SFAS 87-determined expense for 2003 by approximately $17 million (Exh. KEDNE/JFB-1, at 39; Tr. 13, at 1716-1719). For these reasons, we find that including the three-year average of pension plan contributions of $18,085,435 in base rates risks overstating Boston Gas' required pension recovery. We do not wish to impose such a risk of over-recovery on ratepayers, for an item as volatile as pension costs have proven to be, especially over a ten-year PBR term. Further, we find that the inclusion of the three-year historical average cash contributions is no longer necessary for recovery of pension costs. Therefore, Company's revenue requirement will be reduced by $18,085,435.

The Company's proposal also seeks to recover carrying charges on its prefunded pension obligation and pension deferrals (Exh. KEDNE/JFB-1, at 41). Carrying charges, as proposed, would be calculated based upon the tax-effected WACC determined in this proceeding (id.).

The Department must determine the following: the appropriateness of recovery from ratepayers of carrying charges on pension and PBOP prepayments; and the cost of money rate to be used if carrying charges are permitted. We will now address each of these questions below.

The Department has generally not allowed the recovery of carrying charges on prepaid balances because of the difficulty in ascertaining whether ratepayers benefit from the prepayments. D.P.U. 84-25, at 59-61. The facts here are quite different, however. As an initial matter, we note that the Department has, in the past, encouraged companies to prefund pension and PBOP plans in order to take advantage of the tax-exempt status of IRS-qualified pension and PBOP plans. D.P.U. 92-111, at 226-227. The prefunding of these plans maximizes the ability of companies to accumulate earnings on pension trust investments on a tax-free basis, thereby producing lower overall costs. Id. In addition, the poor market performance of the past several years, coupled with an extraordinary decline in interest rates, has required the Company to make even greater contributions to fund their pension plans (Exh. KEDNE/JFB-1, at 34). These payments may result in an unusually high prepaid pension balance (id.). Because of the benefits which inure to ratepayers from these payments and the fact that prepaid balances arising from forces at work in the economy at large and outside the Company's control, the Company should no longer absorb the money costs on these significant cash outlays. Accordingly, we will allow carrying charges to be recovered from customers on prepaid pension and PBOP balances.

There is a cost of money associated with pension deferral and with prepaid pension amounts. The Department has authority in appropriate circumstances to allow carrying charges or amounts amortized. See, e.g., 390 Mass. 208, at 228, 231. The money tied up for this purpose is not fairly characterized as a short-term debt but must, consistent with the long-term-investment nature of workers' pensions and PBOP, come from the Company's long–term capital.

Therefore, it is appropriate to employ the WACC that is applied to a petitioner-company's rate base and apply it to pension costs because there really is no principled difference between the Company's investment in rate base and its investment in pensions and PBOP. The Department also applies the WACC to calculate cash working capital, that long-term fund which must be set aside to draw on and then replenish for short-term needs. Like pension expenses, the demands on the cash-working capital fund may fluctuate; but the need for the fund or expense exists over the long-term and is treated accordingly. For these reasons, the Department approves the Company's request that it receive the WACC as the carrying charge rate for the prepaid pension and PBOP balances.

The final component of the Company's proposal regards the ten-year amortization of the $44 million PBOP transition obligation amount remaining on December 31, 2002 (Exh. KEDNE/JFB-1, at 43). According to the Company, the amortization of the PBOP transition obligation costs is currently included in its base rates (Tr. 22, at 3022-3023). The Company proposes to include this obligation in the reconciling mechanism for reasons of regulatory consistency (id. at 3022-3023). Under this proposal, the Company would begin

collecting approximately $4.4 million through the reconciling mechanism beginning on November 1, 2003 (Exh. AG-11-19, Att.).

The Department finds that the PBOP transition obligation, however, is distinct from the Company's pension expense. It has a different amortization period and is proposed without carrying charges (Tr. 22, at 3022-3023). Further, the Company's proposes that its PBOP expense continue to be recovered in base rates (id. at 3023). Accordingly, the Department orders the Company to continue to recover its PBOP and PBOP transition costs through base rates.

The Department will allow the reconciling mechanism to operate in the following way. On November 1, 2003, the Company will be eligible to recover, outside of base rates, its test year SFAS-determined pension amount.[131] On September 15, 2004 and every year thereafter, in conjunction with its annual PBR filing, the Company will commence reconciling its SFAS-determined pension expense for the prior calendar year, plus previously unamortized balances, with the amount included in rates during that period, and amortize that amount over three years ("Reconciliation Amount").[132] In addition, the Company will be allowed to recover carrying costs[133] applied to the average annual prepaid pension balance expense and the unamortized deferred pension expense, net of deferred income taxes. The Reconciliation

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131 The record shows this amount to be $6,230,016 (Exh. KEDNE/JFB-1, at 39; Tr. 13, at 1716-1719).

132 The previously unamortized balances on November 1, 2004 is zero.

133 Carrying costs shall be based on the after tax WACC of 9.08 percent (Sch. 5, Attached).

Amount and the carrying costs will be collected from, or refunded to, customers on an equal cents per therm basis over the following twelve months, through the Company's Local Distribution Adjustment Factor. The Company shall apply the prime rate on its reconciliation of forecast recovery to actual recovery consistent with 220 C.M.R. § 6.08(2).

V. CAPITAL STRUCTURE AND RATE OF RETURN

A. Capital Structure

1. Introduction

At the end of the test-year, Boston Gas' capital structure consisted of 14.50 percent long-term debt, 0.96 percent preferred stock, and 39.65 percent common equity (Exh. KEDNE/PJM-2, at 36). The remaining 44.89 percent of capitalization represents $650,000,000 in acquisition debt that Keyspan incurred when it purchased Eastern Enterprises (id.). When Keyspan acquired Eastern Enterprises in 2000, it paid approximately $1.127 billion over book value for Eastern Enterprises' assets, thus creating a goodwill balance of approximately $1.127 billion (Exh. AG 1-2K(2)(aa) at 12).[134] Pursuant to GAAP, Keyspan allocated this goodwill balance amongst its Eastern Enterprises acquisitions, including $812,950,019 to Boston Gas (Exh. KEDNE/PJM-2 [rev. 2] at 36, 38; AG 1-2B(1)(c) at F-7). As of the end of the test year, the unamortized goodwill balance included on the books of Boston Gas was $790,284,582, consisting of $650,000,000 in debt and $140,284,582 in equity

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[134] An acquisition premium, or goodwill, is generally defined as representing the difference between the purchase price paid by a utility to acquire plant that previously had been placed into service and the net depreciated cost of the acquired plant to the previous owner. Mergers and Acquisitions, D.P.U. 93-167-A at 9 (1994).

(Exhs. KEDNE/PJM-1, at 36; KEDNE/PJM-2, at 36; KEDNE/PJM-2 [supp.] at 202; Tr. 1, at 28).[135]

The Company proposes to remove $650,000,000 in acquisition debt and $140,284,582 in equity associated with goodwill from its capital structure (Exh. KEDNE/PJM-1, at 36). The Company also proposes to reduce its preferred stock by $1,500,000 to recognize a redemption in September 2003 (id.). These proposed adjustments result in a capital structure that is 32.01 percent long-term debt, 1.88 percent preferred stock, and 66.11 percent equity (id.; Exh. KEDNE/PJM-2, at 36). The Company, however, proposes to further impute an equity component of 50 percent for purposes of calculating its WACC (Exh. KEDNE/PJM-1, at 36). This imputation results in proposed capital structure consisting of 48.16 percent debt, 1.84 percent preferred stock, and 50 percent common equity (id.).

2. Positions of the Parties

a. Attorney General

The Attorney General urges the Department to reject the Company's proposal to remove $650,000,000 in acquisition debt and $140,284,582 in equity associated with goodwill from Boston Gas' capital structure (Attorney General Brief at 78-79; Attorney General Reply Brief at 42). The Attorney General contends that Boston Gas has not issued any long-term debt to the market in the last seven years, and does not expect to issue any for at least the next five years (Attorney General Brief at 79, citing Exh. AG 1-13). The Attorney General argues

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[135] This allocation among acquired affiliates is generally referred to as "pushing down" the acquisition premium, or "push-down" accounting (Tr. 5, at 505).

that Boston Gas has been, and likely will continue to be, financed by debt issued by Keyspan (Attorney General Brief at 79). Therefore, the Attorney General argues that the capitalization associated with goodwill attributable to the Eastern Enterprises merger should be included in determining Boston Gas' capital structure (id.).

The Attorney General also urges the Department to reject the Company's proposed imputed capital structure, and instead use Boston Gas' actual end of test-year capital structure ratios to compute the WACC (Attorney General Reply Brief at 42). The Attorney General contends that the Company has not shown that its capital structure "deviates substantially from sound and well established utility practice," and, therefore, has not satisfied the Department's precedent for the use of a hypothetical capital structure for ratemaking purposes (Attorney General Brief at 77-78, citing D.T.E. 01-50, at 25; Assabet Water Company, D.P.U. 95-92, at 33; Wylde Wood Water Works, D.P.U. 86-93, at 25 (1987); Blackstone Gas Company, D.P.U. 1135, at 4 (1982)). Specifically, the Attorney General argues that the Company's actual debt ratio at the end of the test-year was 59.4 percent, approximately the same debt ratio as its parent Keyspan, both of which have "A" bond ratings (Attorney General Brief at 78, citing Exhs. KEDNE/PRM-1, at 18; AG 1-16). Therefore, the Attorney General argues that both the Company and the financial markets have determined that a 59.4 percent debt ratio is reasonable and cost efficient (Attorney General Brief at 78; Attorney General Reply Brief at 41).

Finally, noting that the Department typically evaluates the effect of a merger on a utility's financial condition, the Attorney General contends that although Boston Gas has

claimed to have removed the direct cost of the acquisition debt from its cost of service, this debt will remain on the books of the Company for an indefinite period of time. The Attorney General argues that ratepayers will be affected by having this debt on the Company's books because it will hinder Boston Gas' ability to issue new debt or to refinance existing debt (Attorney General Brief at 4, 79; Attorney General Reply Brief at 10-11).[136]

b. Boston Gas

The Company argues that the intangibility of goodwill makes it inappropriate for consideration as a component in a utility's capitalization (Boston Gas Brief at 125, citing New England Power Company, D.T.E. 00-53 (2000)). Therefore, the Company proposes to remove the capitalization associated with goodwill attributable to the Eastern Enterprises merger for the purposes of determining its capital structure (Boston Gas Brief at 124-125). Although this acquisition premium is booked as a goodwill asset on the Company's balance sheet, Boston Gas argues that it is not included in the Company's rate base nor is it otherwise recoverable in rates (id. at 128). The Company argues that it is well established that such amounts should also be excluded from its capitalization (id., citing Southern Union Company, D.T.E. 02-27, at 12 (2002); D.T.E. 00-53).

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136 The Attorney General also urges the Department to evaluate the "push down" of Keyspan's acquisition debt onto Boston Gas and its effect on the Company and its ratepayers, by applying the "no net harm standard" prescribed in G.L. c. 164, § 96 by way of analogy to the merger of holding companies (Attorney General Brief at 12, n.5, citing 438 Mass. 256, 268-269; Cambridge Electric Light Company v. Department of Public Utilities, 33 Mass. 536, 538 (1956)).

The Company disputes the Attorney General's contention that the 59 percent debt ratio which occurs in the absence of an adjustment for the merger-related capitalization is reasonable (Boston Gas Reply Brief at 85-86). Instead, the Company maintains that the capitalization associated with its unadjusted capital structure is $1,447,903,970 -- an amount exceeding the Company's $626,935,813 rate base by $820,968,157 (id., citing Exh. KEDNE/PJM-2, at 1). Boston Gas argues that any market acceptance of the non-merger adjusted capital structure includes consideration of the higher rate base associated with goodwill (id. at 86). Because the Company is not requesting that the goodwill associated with the Keyspan merger be recovered in rates, Boston Gas contends that the effect of the merger must be eliminated from its capital structure (id.). If the Department does not remove the capitalization associated with goodwill for the purposes of determining Boston Gas' capital structure, the Company argues that its rate base must be increased to approximately $1.448 billion (id.).

The Company further argues that the removal of the capitalization attributable to goodwill results in a "relatively high" equity ratio that is not typical for utility ratemaking purposes (Boston Gas Brief at 125-126; Boston Gas Reply Brief at 85). In order to maintain a reasonable debt-to-equity ratio, the Company contends that it is necessary to impute a hypothetical capital structure consisting of 50 percent equity for the purposes of computing the WACC (id.). Boston Gas argues that a common equity ratio of 50 percent is reasonable because (1) it is representative of the capital structure of companies that are considered to be of generally comparable risk to Boston Gas, (2) it is compatible with the ratio expected by the credit rating agencies for an "A" bond rating, and (3) it has been accepted by the Department

in previous rate cases and other financial proceedings (Boston Gas Brief at 126, citing Exhs. KEDNE/PRM-1, at 19, 21; AG-14-10; D.T.E. 01-50, at 25). In addition, Boston Gas argues that its proposed common equity ratio of 50 percent is consistent with the common equity ratio it maintained from 1997 until the merger (id., citing Exh. KEDNE/PRM-2, at 2).

3. Analysis and Findings

a. Introduction

A company's capital structure typically consists of long-term debt, preferred stock, and common equity. Berkshire Gas Company, D.T.E. 01-56, at 97 (2002); Pinehills Water Company, D.T.E. 01-42, at 17-18 (2001); D.T.E. 99-118, at 62; D.P.U. 87-228, at 22. The ratio of each capital structure component to the total capital structure is used to weight the cost (or return) of each capital structure component to derive a WACC. The WACC is used to calculate the return on rate base for calculating the appropriate debt service and profits for the company to be included in revenue requirements. D.T.E. 01-42, at 18; South Egremont Water Company, D.P.U. 86-149, at 5 (1986).

The Department will normally accept a utility's test year-end capital structure, allowing for known and measurable changes, unless the capital structure deviates substantially from sound utility practice. High Wood Water Company, D.P.U. 1360, at 26-27 (1983); D.P.U. 1135, at 4. In reviewing and applying utility company capital structures, the Department seeks to protect ratepayers from the effect of excessive rates of return. D.T.E. 01-50, at 25; D.P.U. 95-92, at 33; D.P.U. 86-93, at 25; D.P.U. 1135, at 4.

Instead of relying on its test year-end capital structure, the Company proposes several adjustments to derive its WACC. First, the Company proposes to remove $790,284,582 in capitalization associated with goodwill attributable to the Eastern Enterprises merger (Exh. KEDNE/PJM-1, at 36). Next, the Company proposes to reduce its preferred stock by $1,500,000 to recognize a sinking fund payment in September 2003 (id.). Finally, the Company proposes to impute a hypothetical capital structure consisting of 50 percent equity, 48.16 percent debt, and 1.84 percent preferred stock (id.).

b. Treatment of Goodwill

The Company argues that it is "well-established" that intangible capitalization such as acquisition-related debt should be excluded from utility capitalization (Boston Gas Brief at 128, citing Southern Union Company, D.T.E. 02-27, at 12; D.T.E. 00-53). On this point, we do not agree. The cases cited by the Company stand only for the proposition that intangible capitalization should be excluded from consideration for the purposes of applying the net plant test. However, on at least one occasion, the Department has found it both reasonable and proper to include the capitalization associated with acquisition premiums in capitalization for ratemaking purposes. Boston Gas Company, D.P.U. 19470, at 80-81 (1978). This difference in treatment of intangible capitalization, including acquisition premiums, is appropriate because of the unique purposes of the net plant test and its effect on capitalization, versus the Department's ratemaking authority embodied in G.L. c. 164, § 94, as detailed below.

Both D.T.E. 02-27, at 12, and D.T.E. 00-53 were financing petitions filed pursuant to G.L. c. 164, § 14. In order for the Department to approve the issuance of stocks, bonds,

coupon notes, or other types of long-term indebtedness by an electric or gas company, the Department must determine, amongst other issues, whether the company has met the net plant test requirements implicit in G.L. c. 164, § 16. Colonial Gas Company, D.P.U. 84-96, at 5 (1984). The purpose of the net plant test is to both protect ratepayers from excessive rates associated with overcapitalization and to assure the creditors of a utility that the company has sufficient tangible assets to cover its liabilities. Colonial Gas Company, D.P.U. 1247-A at 7 (1982); Report of the Department of Public Utilities Relative to the Capitalization of Gas and Electric Companies, Senate Document No. 315, at 8-15 (January 1922). Because goodwill is not directly associated with a utility's tangible plant assets, it is appropriate to exclude goodwill from capitalization for the purposes of deriving the net plant test requirement. D.T.E. 02-27, at 12; Southern Union Company, D.T.E. 01-52, at 11 (2001); D.T.E. 00-53, at 8-9.

In contrast, the Department's ratemaking authority is derived from G.L. c. 164, § 94. The ratemaking process relies on a return-on-rate-base concept, in which a WACC is determined and applied to rate base in order to derive an appropriate return requirement. See D.P.U. 95-92, at 31; D.P.U. 87-228, at 22; D.P.U. 1580, at 13; New England Telephone and Telegraph Company, D.P.U. 7750 (1949)
(83 P.U.R. NS 238, 282). Because the Department consistently applied original-cost rate base principles and exercised stringent oversight over utility securities issues, a utility's rate base frequently coincided with its total capitalization during the early years of the return-on-rate-base method. D.P.U. 7750 (83 P.U.R. NS 238, 272); Plymouth County

Electric Company, D.P.U. 6369 (1941) (39 P.U.R. NS 20). In the ensuing years, however, evolving regulatory standards for non-plant components of rate base (e.g., cash working capital, deferred income taxes),
as well as the increased role of retained earnings in capitalization, have resulted in situations where total capitalization and total rate base materially differ in amount. See, e.g., Massachusetts Electric Company, D.P.U. 95-40-C at 18-19 (1995).

This disparity between capitalization and rate base, in and of itself, does not constitute a defect in the ratemaking process, because it is the amount of rate base, not capitalization, that determines the level of capital costs that are recoverable through rates. D.P.U. 1247-A at 7. However, in this instance, the disparity between capitalization and rate base is quite significant. The difference is large enough that we can not conclude that the $650,000,000 of long term debt supports, or is in any way associated with items included in the Company's proposed rate base. The unamortized balance of goodwill at the end of the test year was $790,284,528 (Exh. KEDNE/PJM-1, at 36). This asset is supported by $650,000,000 in long term-debt and $140,284,582 in equity (id.). The Company's capital structure of $656 million, excluding the debt and associated goodwill, is substantially more than adequate to support Boston Gas' proposed $627 million rate base (Exh. KEDNE/PJM-1, at 36, 38). For these reasons, we accept the Company's proposal to remove the capitalization associated with

goodwill attributable to the Eastern Enterprises merger for the purposes of determining its capital structure.[137]

c. Preferred Stock Redemption

The Company proposes to reduce its preferred stock by $1,500,000 to recognize a redemption in September 2003 (Exh. KEDNE/PJM-1, at 36). Adjustments to test-year capitalization to recognize redemptions, retirements, or issuances of new debt or equity are allowed, provided they are known and measurable and the proposed issuance or retirement of securities has actually taken place by the date of the Order. D.P.U. 90-121, at 157; Boston Gas Company, D.P.U. 88-67, Phase I at 174 (1988). Because the sinking fund payment in

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[137] While the Company suggests that, had we included the acquisition-related debt in capitalization, the Department would also have been required to make a corresponding increase in rate base, we have a long-established policy of excluding goodwill (whether positive or negative) from rate base. D.P.U. 93-167-A at 11-12; Boston Gas Company, D.P.U. 88-67, Phase I at 26-27 (1988); Boston Gas Company, D.P.U. 17574, at 11 (1973); Springfield Gas Light Company, D.P.U. 17139, at 3 (1971); Boston Gas Company, D.P.U. 17138, at 7-8 (1971); Millbury Water Company, D.P.U. 4932, at 4 (1935). This exclusion of goodwill from rate base is based on the regulatory principle that the original book value of used and useful property is included in rate base, and not its market value as may be determined from time to time. Boston Edison Company, D.P.U. 84-47, at 5 (1985).

In D.P.U. 93-167-A at 18-19, the Department amended its policy of per se exclusion in favor of case-by-case consideration of acquisition premiums as a factor in the cost-benefit analysis required as part of a merger and acquisition petition. Consequently, the Department will allow recovery of acquisition premiums as a component of the general reckoning of cost and benefit conducted under the standards of G.L. c. 164, § 96, which requires a showing that the costs or disadvantages of the transaction are accompanied by benefits that warrant their allowance. D.P.U. 93-167-A at 7. Nevertheless, rate base exclusion of acquisition premiums continues to remains the norm. Southern Union Company, D.T.E. 03-64, at 10 (2003); D.T.E. 02-27, at 12.

September of 2003 is both known and measurable, the Department will reduce the Company's test year-end preferred stock balance by $1,500,000 (Exh. KEDNE/PJM-1, at 36).

d. Imputed Capital Structure

The Company argues that the removal of its goodwill from capitalization creates a capital structure that is overly-reliant on common equity (i.e. 32.01 percent long-term debt, 1.88 percent preferred stock, and 66.11 percent equity) (Exhs. KEDNE/PJM-1, at 36; KEDNE/PJM-2, at 36). Therefore, the Company proposes to instead use a hypothetical capital structure consisting of 48.16 percent debt, 1.84 percent preferred stock, and 50 percent common equity (Exh. KEDNE/PJM-2 [rev. 2] at 36).

With our acceptance of the Company's proposal to remove goodwill from its capital structure, the Company's capital structure, adjusted for the September 2003 sinking fund payment of $1,500,000, consists of 32.01 percent long-term debt, 1.88 percent preferred stock, and 66.11 percent common equity. The Department uses a policy in reviewing and applying utility company capital structures which, inter alia, seeks to protect ratepayers from the effects of excessive rates of return. D.P.U. 95-92, at 11, 33. The Department has used a hypothetical capitalization for ratemaking purposes when the actual capitalization is found to deviate substantially from sound utility practice. D.T.E. 01-50, at 25; D.P.U. 95-92, at 33; D.P.U. 1135, at 4. When the Department has imputed a utility's capital structure, we have typically relied for ratemaking purposes on a capital structure consisting of 50 percent debt and 50 percent equity. D.T.E. 01-50, at 25; D.P.U. 1360, at 26-27.

In the instant case, we find that the Company's actual test year-end capital structure, adjusted for the removal of goodwill and the September 2003 sinking fund payment, is overly-reliant on equity[138] and, therefore, deviates substantially from sound utility practice. D.T.E. 01-50, at 25. See also Southern Union Company, D.T.E. 03-3, at 16 (2003). Boston Gas' proposed capital structure brings the Company's common equity balance more into alignment with sound utility practice, and is, therefore, consistent with Department practice. Accordingly, the Department accepts the Company's proposed capital structure. This produces a capital structure consisting of 48.16 percent long-term debt, 1.84 percent preferred stock, and 50.0 percent common equity. The Department will use these capitalization ratios in deriving the Company's WACC.

B. Cost of Debt and Preferred Stock

1. Introduction

Boston Gas proposes a rate of 8.14 percent for its debt (Exh. KEDNE/PJM-1, at 37). The Company determined its proposed cost of debt by first multiplying the amount of each long-term debt instrument by its respective coupon rate, producing a weighted average coupon rate of 8.01 percent (Exh. KEDNE/PJM-2, at 37; RR-AG-19).[139] The Company then added the test year amortization expense for each debt issue, totaling $276,560 to the annual interest

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138 Boston Gas' adjusted capital structure has a pro forma 66 percent common equity ratio.

139 Because Boston Gas did not include its acquisition-related debt "pushed down" from Keyspan in its proposed capital structure, the Company also did not include the cost of this debt in the calculation of its proposed weighted cost of debt (Exh. KEDNE/PJM-2, at 37).

expense for the corresponding debt issue to arrive at an effective interest rate for each debt instrument (Exhs. KEDNE/PJM-1, at 37; KEDNE/PJM-2, at 37). The Company applied the resulting weighted average as the cost of debt for its proposed hypothetical capital structure (id.; Exh. KEDNE/PJM-2, at 36).

The Company proposes a rate of 6.42 percent for its preferred stock (id.). The Company determined this rate by annualizing the quarterly dividend of $.4013 per share, and dividing the annual dividend of $1.6052 by the $25 share price (RR-DTE-99).

2. Positions of the Parties

a. Attorney General

The Attorney General argues that, because the Company's proposal fails to include all of its outstanding long-term debt in capital structure (i.e., the debt attributable to Keyspan's acquisition of Eastern Enterprises), Boston Gas' proposed overall cost of debt is incorrect (Attorney General Brief at 79). The Attorney General contends that the cost of the debt that was "pushed down" from Keyspan as a result of the Eastern Enterprises merger should also be factored into Boston Gas' cost of debt, which would reduce the Company's overall cost of debt from 8.14 percent to 7.87 percent (id. at 78-79, citing Exh. KEDNE/PJM-2, at 36; Attorney General Reply Brief, Att. 8).

Finally, the Attorney General argues that the Company wrongly assumes the cost of the debt used to "make up" the incremental amount added to the actual debt in the proposed hypothetical capital structure was the same as the cost of the debt issued by Boston Gas in 1995 (Attorney General Brief at 78). The Attorney General suggests that, even if the Department

were to allow the Company to remove its acquisition-related debt from capitalization and rely on an imputed capital structure, it would be necessary to recognize the lower interest rate associated with the acquisition-related debt in determining an appropriate hypothetical cost of debt (id. at 79; Attorney General Reply Brief at 41).

b. Boston Gas

Boston Gas argues that it correctly calculated its cost of debt by multiplying the amount of each outstanding long-term debt instrument by its respective coupon weight, and then including the amortization of test year debt-issuance expenses (Boston Gas Brief at 126-127). The Company reasons that it would be inappropriate to include the $650,000,000 in acquisition-related debt in capital structure, thus making it inappropriate to include the cost of acquisition-related debt in the cost of long-term debt (id. at 128-129; Boston Gas Reply Brief at 86).

3. Analysis and Findings

As an initial matter, the Company has appropriately calculated its preferred stock rate by dividing the annualized dividend of $1.6052 per share by the preferred instrument's face value of $25 per share (RR-DTE-99). Therefore, we find that the cost of preferred stock is 6.42 percent. In Section III.D.3, above, we removed the $650,000,000 in acquisition-related debt and $140,284,582 in acquisition-related equity from Boston Gas' capitalization. The Company's acquisition-related debt carries a cost identical to the overall cost of the debt instruments that Keyspan issued to acquire Eastern Enterprises, which is 7.78 percent (Exh. AG 1-7; Tr. 24, at 3368-3369).

The Company proposes that we use its imbedded cost of debt (8.14 percent) when imputing the hypothetical capital structure (Boston Gas Brief at 128-129; Boston Gas Reply Brief at 86). However, the Attorney General urges the Department to instead apply the cost of the acquisition-related debt when determining an appropriate hypothetical cost of debt (Attorney General Brief at 79; Attorney General Reply Brief at 41). When imputing a capital structure, it is also necessary to impute a cost of debt for the Company. D.P.U. 95-92, at 29. An imputed cost of debt is based on a number of considerations, including recent financings by the petitioner or other utilities, the petitioner's access to the capital markets, and current interest rates. D.T.E. 01-50, at 24; D.T.E. 01-42, at 19 (2001); D.P.U. 92-95, at 33-34; South Egremont Water Company, D.P.U. 95-119/122, at 24 (1996). The Company's proposal to use its imbedded cost of debt of 8.14 percent, fails to recognize the lower interest rates that have occurred since the Company's issuance of this debt between 1989 and 1995 (see Exh. AG 1-2B(8)(a) at 31). Instead, we find it appropriate to use the overall cost of the debt instruments that Keyspan issued to acquire Eastern Enterprises, which is 7.78 percent, as a proxy for the cost of debt if Boston Gas were to acquire it under current market conditions. This 7.78 percent debt, when added to the Company's other long-term debt instruments, results in an overall cost of debt of 8.02 percent.[140] Accordingly, the Department finds that the Company's overall cost of debt is 8.02 percent.

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[140] The calculation was made as follows: (($210,000,000 / $315,719,399) x 8.14 percent) + (($105,719,399 / $315,719,399) x 7.78 percent) = 8.02 percent. The $315,719,399 hypothetical debt balance is derived by taking the Company's total pro forma capitalization of $656,119,388, subtracting the $328,059,694 in imputed common equity then subtracting the $12,340,295 in preferred stock.

C. Rate of Return on Equity

1. Introduction

The Company proposes a 12.18 percent rate of return on common equity ("ROE") (Exh. KEDNE/PRM-1, at 2). In determining its proposed ROE, the Company relied on the following: (1) a discounted cash flow ("DCF") analysis; (2) a risk premium analysis; (3) an analysis using the capital asset pricing model ("CAPM"); and (4) a comparable earnings approach[141] (Exh. KEDNE/PJM-1, at 4). The range of ROE calculations derived from the Company's application of these models was 12.10 percent using the DCF model to 14.64 percent using the CAPM, with the average of the four approaches being 13.22 percent (Exh. KEDNE/PRM-1, at 5). The Company took the arithmetic average of the results of DCF model (12.10 percent) and the risk premium model (12.25 percent) to arrive at its proposed ROE of 12.18 percent (id.).

Because Boston Gas is a wholly-owned subsidiary of Keyspan, there are no market data for the Company's common stock, and consequently, no means to assess directly investor's expectations of the Company's required return. Therefore, the Company provided an analysis of eight gas distribution companies it considers to be of generally comparable risk to Boston Gas ("Comparison Group") (Exh. KEDNE/PJM-1, at 4).[142] The Comparison Group includes

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141 The Company also uses the term "capital earnings approach" to refer to this model (see e.g., Boston Gas Brief at 129, 148).

142 Boston Gas' selection criteria included companies that (1) are engaged in similar business lines, (2) have publicly-traded common stock that is listed on the New York Stock Exchange, (3) are contained in the Value Line investment survey in the industry

(continued…)

AGL Resources, Inc., Atmos Energy Corporation, New Jersey Resources Corp., NICOR, Inc., Peoples Energy, Piedmont Natural Gas Co., South Jersey Industries, Inc., WGL Holdings, Inc. (Exh. KEDNE/PRM-2, at 5). In addition, the Company provided an analysis of the fundamental risk of Boston Gas compared to the Comparison Group and the Standard and Poor's ("S&P") Public Utility Index (Exh. KEDNE/PRM-1, at 15).[143]

2. ROE Models

a. Discounted Cash Flow Analysis

The DCF model is predicated on the theory that a stock's price represents the present value of all investor expected cash flows from the stock, discounted at an appropriate risk-adjusted rate of return. By substituting the value of the common stock, the discounted rate of return can be determined (Exh. KEDNE/PRM-3, at E-3). The DCF model is represented by the following equation where D_1 is the expected dividend to be paid in the next period (period one), P_0 is the current market price of the stock, and g is the expected growth rate:

$$ROE = D_1 / P_0 + g$$

(see id.).

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142 (…continued)
group entitled "natural gas distribution," (4) have operations in the Northeastern, Great Lakes and Southeastern regions of the U.S., (5) have not cut or omitted their dividend, (6) have at least 70 percent of their assets represented by gas operations, and (7) are not currently the target of a merger or acquisition (Exh. KEDNE/PRM-1 [rev. 2] at 14-15).

143 The S&P Public Utility Index is a market capitalization-weighted index of approximately 37 natural gas and electric companies (Exh. KEDNE/PRM-1, at 15).

As the dividend yield, the Company calculated the average yield for the Comparison Group for the six-month period June through December 2002 at 5.11 percent and then adjusted this figure to 5.28 percent to account for higher expected dividends for the future (Exh. KEDNE/PRM-1, at 27-28). As the growth rate, the Company analyzed the five-year and ten-year historical growth rates and the five-year forecast growth rates in earnings-per-share, dividends-per-share, book value-per-share, and cash flow-per-share for the Comparison Group (id. at 29-31). Relying on the forecasts of earnings-per-share, the Company arrived at a prospective growth rate of six percent (id. at 33). Applying the yield and growth inputs, the DCF analysis determined that the ROE is 11.28 percent (id. at 38). The Company then adjusted the DCF-determined ROE for financial risk associated with the book value of capitalization through a "leverage adjustment" of 0.82 percent, arriving at a final DCF cost rate of 12.10 percent (id. at 40).[144]

b. Risk Premium Analysis

Risk premium analyses are based on the assumption that equity securities are riskier than debt and, therefore, equity investors require a higher ROE. D.T.E. 02-24/25, at 217. Simple risk premium methods take the currently observable market returns such as government or corporate bond yields, and add an increment to account for the additional equity risk. Id. The risk premium model is represented by the following equation where i is the long-term bond yield and RP is the equity risk premium:

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[144] The proposed leverage adjustment is intended to account for differences in risk that are attributable to changes in financial leverage when market prices and book values diverge (Exh. KEDNE/PJM-1, at 26-27).

$$ROE = i + RP$$

(Exh. KEDNE/PRM-1, at 46).

To arrive at a long-term bond yield of 7.25 percent, Boston Gas relied on historical interest rates and forecast yields on A-rated public utility bonds (id. at 41). The Company determined forecast yields on A-rated public utility bonds by using the Blue Chip Financial Forecasts ("Blue Chip") and adding a two percent interest rate spread between the yield on long-term Treasury bonds and A-rated public utility bonds to account for the specific credit quality of the public utility bond issuer (Exh. KEDNE/PRM-3, App. F).

To calculate the equity risk premium, the Company calculated a "risk rate differential" by comparing the market returns on utility stocks (using the S&P Public Utility Index) and the market returns on utility bonds (Exh. KEDNE/PRM-1, at 42-43, App. G). The Company measured the central tendency of historical returns over several holding periods and arrived at a common equity risk premium of 5.32 percent (id. at 42, 45; Exh. KEDNE/PRM-2, Sch. 9). After analyzing differences in fundamental measures between the Comparison Group and the S&P Public Utilities Index, the Company reduced the equity risk premium to five percent (Exh. KEDNE/PRM-1, at 45).[145] Using these inputs (7.25 percent long-term bond yield and five percent equity risk premium), the Company arrived at a ROE of 12.25 percent using the risk premium approach.

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[145] These fundamental measures included size, market ratios, common equity ratios, return on book equity, operating ratios, coverage, quality of earnings, internally generated funds and betas (Exh. KEDNE/PRM-1, at 45).

c. Capital Asset Pricing Model

The CAPM is a more elaborate version of the risk premium analysis that attempts to recognize the riskiness of a utility's common stock in relation to the overall riskiness of the market. The CAPM adds to the risk-free rate, an adjustment for market-related or systematic risk, represented by beta (measuring the risk that can not be eliminated from a portfolio of assets through diversification) (Exh. KEDNE/PRM-1, at 46-47). The CAPM formula is as follows, where R_f is the risk-free rate, β is the beta, expressed as a ratio of a firm's return relative to that of the overall market, and R_m is the market return:

$$ROE = R_f + \beta (R_m - R_f)$$

(id. at 49; Exh. KEDNE/PRM-3, App. H at 2).

The Company performed a CAPM analysis for the Comparison Group. Using both historical and forecast yields on long-term Treasury bonds as a proxy, the Company applied 5.25 percent as the risk-free rate (Exh. KEDNE/PRM-1, at 49). The Company derived an average 0.68 beta for the Comparison Group using data from the Value Line Investment Survey (Exh. KEDNE/PRM-2, Sch. 10, at 1). Using a formula that "un-leverages" the Value Line betas and then "re-leverages" them for common equity ratios using book values instead of market values, the Company adjusted the Comparison Group beta to 0.81 (Exh. KEDNE/PRM-1, at 48). To determine the market risk premium of 9.84 percent (R_m - R_f), the Company averaged a historical market performance of seven percent with the Value Line forecast of 12.68 percent (id.). Using these values (5.25 percent risk free rate, and 9.84 percent market premium multiplied by the 0.81 leverage adjusted beta), the Company

derived a 13.22 percent ROE using the CAPM (id. at 49). The Company then adjusted this ROE by 1.42 percent to account for the relative market capitalization of the Comparison Group, arriving at a 14.64 percent ROE (id. at 50).

d. Comparable Earnings Approach

The comparable earnings approach relies on historical and forecast returns for non-regulated companies as a measure of the regulated utility's ROE. Parameters identifying a group of non-regulated companies with risk characteristics similar to those of the utility being examined are selected, including financial strength, price stability, and market performance (id. at 52). The formula generally applied is as follows, where R_h is the historical rate of return and R_p is the forecast rate of return:

$$ROE = (R_h + R_p) / 2$$

(id. at 55).

To identify its comparable risk companies, Boston Gas selected historical and forecast returns for non-regulated companies from the Value Line Investment Survey for Windows (id. at 53). Using selection criteria based on the risk of the Comparison Group, the Company identified 49 non-utility companies it considered to have comparable risks to Boston Gas (Exh. KEDNE/PRM-2, Sch. 11, at 2).[146] Based on the results of this analysis, the ROE for non-utility companies comparable to Boston Gas is 13.90 percent (Exh. KEDNE/PRM-1, at 55).

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[146] The selection criteria was divided into the following six categories: (1) timeliness rank; (2) safety ranking; (3) financial strength; (4) price stability; (5) Value Line betas; and (6) technical rank (Boston Gas Brief at 148, citing Exh. KDNE/PRM-1, at 53).

3. Positions of the Parties

a. Attorney General

i. Introduction

After making several recommended corrections to the Company's ROE analysis (as discussed below), the Attorney General recommends an 8.99 percent allowed ROE (Attorney General Brief at 80-85; Attorney General Reply Brief at 42). In addition, the Attorney General argues that there are several aspects of the Company's filing that, if approved by the Department, will require further adjustments to Boston Gas' ROE. First, the Attorney General disputes the Company's contention that its recommended ROE is "conservative" because it does not account for the risk that the Company may face under its proposed PBR plan. On the contrary, the Attorney General argues that several elements of the Company's proposed PBR plan make the Company less risky. Specifically, the Attorney General argues that the following aspects of the proposed PBR plan protect Boston Gas from the risk it will not earn its allowed rate of return due to "unforseen events": (1) the exogenous cost factor; (2) the inflation factor; and (3) the earnings sharing mechanism (Attorney General Reply Brief at 42, n.35).

In addition, the Attorney General argues that the Company's proposed pension reconciliation mechanism shifts pension and PBOP volatility risk to ratepayers (Attorney General Brief at 44). Therefore, if the Department allows the Company's proposed reconciliation mechanism, the Attorney General argues that the Department must make a corresponding reduction to Boston Gas' ROE (id. at 44-45, citing Exh. AG-42, at 19). The

Attorney General argues that, despite the Company's failure to provide any quantification of the pension volatility risk, it cannot argue that no such risk exists (Attorney General Brief at 44-45). The Attorney General disputes Boston Gas' claim that approval of the pension mechanism merely maintains the "status quo" (Attorney General Reply Brief at 28, citing Boston Gas Brief at 194). The Attorney General contends that fewer than half of the companies in the Comparison Group and no other Massachusetts gas distribution companies have pension adjustment mechanisms (id. at 28).[147] According to the Attorney General, the Company itself states that the proposed pension mechanism will protect Boston Gas' earnings and equity from "volatile swings in financial markets" (id., citing Boston Gas Brief at 198). Therefore, the Attorney General argues that the Department must recognize these new "protections" in determining Boston Gas' authorized ROE (id. at 28). The Attorney General suggests that an appropriate adjustment to Boston Gas' ROE to account for the reduction in risk to investors as the result of an approved pension reconciliation mechanism is 50 basis points (Attorney General Brief at 45, citing Tr. 26, at 3559-3561).

Finally, the Attorney General argues that the Company's proposed weather stabilization clause will significantly reduce its weather-related risks and shift these risks to ratepayers. Therefore, if the Department approves the Company's weather stabilization proposal, the

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[147] Of the eight companies in the comparison group, New Jersey Natural Gas and South Jersey Gas have mechanisms in place allowing for recovery of pension expense, and Washington Gas Light has a mechanism for recovery of FAS 106 expenses (Exh. DTE 3-4; RR-DTE-63). Atmos Energy has a rate stabilization mechanism that adjusts for various costs, including pension and PBOP (Exh. DTE 3-4).

Attorney General argues that the Department must make a corresponding reduction to Boston Gas' allowed ROE (id. at 95, citing D.P.U. 92-111, at 60-61; D.P.U. 92-210, at 199).

ii. Comparison Group

The Attorney General argues that, although Boston Gas has changed the companies that comprise its Comparison group, its analysis remains basically the same as what the Department has rejected in other cases (id. at 80, citing D.T.E. 01-56; Boston Gas Company, D.P.U. 96-50). The Attorney General argues that the Company's analysis "grossly overstate[s]" the cost of capital for the Comparison Group (id. at 80).

The Attorney General disputes the Company's claim that Boston Gas has more variability in earned returns and, therefore, is more risky than the Comparison Group (Attorney General Reply Brief at 42, citing Boston Gas Brief at 131-132). The Attorney General argues that just the opposite is true, namely that Boston Gas has less variability in earned returns than the Comparison Group and, therefore, is less risky (id. at 43). To reach this conclusion, the Attorney General argues that the statistics calculated by the Company for the Comparison Group are determined by averaging the individual statistics for each of the companies in the group (id., citing Exh. KEDNE/PRM-2, at 4). The Attorney General contends that by determining the variability of the earned returns on common equity for the Comparison Group after averaging the individual company returns, the Company has inappropriately reduced their variability (id. at 43). The Attorney General argues that the appropriate calculation would determine the variability of the earned returns for each of the companies in the Comparison Group individually and then average those individual measures

of variability. Using this latter method, the Attorney General argues that variability of earned returns for the Comparison Group is "significantly higher" than that of Boston Gas (id.).

Finally, the Attorney General argues that the companies in the Comparison Group each have significant investments in risky non-utility businesses (e.g. energy trading, natural gas marketing, unregulated energy services, gas storage, oil and gas exploration, gas equipment, and electric generation) (id. at 43-44, citing Exh. AG 14-19). Accordingly, the Attorney General argues that Boston Gas, as a stand-alone gas distribution company, has less investment risk than the Comparison Group (id. at 44).

iii. Discounted Cash Flow Analysis

The Attorney General faults the Company's DCF analysis in the following two areas: (1) its calculation of the current dividend yield; and (2) its estimate of the growth rate (Attorney General Brief at 81-85). With respect to the dividend yield, the Attorney General contends that the Company must use the latest available information to calculate an appropriate dividend yield proxy (id. at 82). Accordingly, when considering the Company's DCF analysis, the Attorney General argues that the Department should apply the most recent six month dividend yield average of 4.88 percent (id., citing AG-RR-67). The Attorney General disputes the Company's contention that use of the most recent six month average dividend yield (for the period ending June 2003) is improper because it is inconsistent with the period chosen by the Attorney General to calculate his risk free rate of return (the period ending April 2003). The Attorney General argues that no temporal inconsistency exists because the risk free

interest rate does not enter into, nor does it affect, the DCF analysis (Attorney General Reply Brief at 45-46, n.38)

With respect to the growth rate, the Attorney General contends that the Company's estimate is inflated because it ignores historical data and is based on unreasonable short-term earnings projections (Attorney General Brief at 83-84). Specifically, the Attorney General argues that the Company's six percent DCF growth rate estimate is (1) 319 basis points above the historical dividend growth rate, (2) 350 basis points above the projected dividend growth rate, and (3) 50 basis points higher than the long-run growth rate forecast for the overall economy (id. at 83, citing Exhs. KEDNE/PRM-2, at 10; AG-14-9; AG-14-20). The Attorney General argues that Boston Gas' optimistic growth rate estimate is not adequately supported, and, instead, is based on forecasts from "sell side" investment analysts, which overestimate the growth rates of the Companies in the Comparison Group (Attorney General Reply Brief at 45, n.37).

The Attorney General argues that the Company's method of basing its DCF growth rate estimate on short-term earnings projections has not proven reasonable over time (Attorney General Brief at 83). The Attorney General contends that the Company, using the same method in its last base rate case, estimated a growth rate of 5.5 percent (id., citing D.P.U. 96-50 (Phase I) at 117). In contrast, the Attorney General claims that, despite one of the longest economic expansions in U.S. history, actual dividends, earnings, and growth rates were each 4.4 percent and below over the last ten years (id. at 84, n.60, citing Exh. KEDNE/PRM-2, at 10).

The Attorney General argues that the Department should require the use of DCF growth rate proxies that are both consistent with historical measures as well as reasonable long-run forecasts of growth (id. at 84). After considering the five-year average measures of historical and forecast growth in dividends per share, earnings per share, and book value per share, the Attorney General argues that four percent is a reasonable estimate of the DCF growth rate (id.). The Attorney General argues that a four percent DCF growth rate is near the upper end of the Company's actual growth rate and the growth rate that Boston Gas can expect to achieve (Attorney General Reply Brief at 45, citing Exhs. KEDNE/PRM-2, at 10; AG-14-20).

Finally, the Attorney General disputes the Company's claim that the long-run forecast growth rate in corporate profits is the best estimate of the growth rate for the companies in the Comparison Group (id. at 45). The Attorney General contends that the growth rate in corporate profits includes all companies in the U.S. economy, both regulated and unregulated. The Attorney General argues that the risk and expected returns for these companies is not comparable to the regulated gas distribution industry (id.). Substituting the Attorney General's recommend current dividend yield of 4.88 percent and growth rate of four percent, the Attorney General contends that DCF model yields an 8.99 percent estimate of ROE (Attorney General Brief at 84-85).[148]

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[148] Using the current dividend yield and growth rate percentages recommended by the Attorney General, the Department calculates a ROE estimate of 8.88 percent using the DCF model (4.88 percent + 4.00 percent).

iv. Risk Premium Analysis

The Attorney General alleges that the Department on numerous occasions has reviewed and rejected risk premium analyses similar to that used by the Company (id. at 91, citing D.P.U. 96-50 (Phase I) at 97; D.P.U. 93-60, at 261; D.P.U. 92-111, at 265-266; D.P.U. 92-210, at 138-139; D.P.U. 90-121, at 171). The Attorney General argues that Boston Gas' risk premium analysis is essentially the same as its CAPM analysis, except that utility bonds are substituted for U.S. Treasury bonds and the S&P Utilities index is substituted for the stock market return (id. at 90, citing Exh. KEDNE/PRM-1, at 42-46, App. G).

In addition, the Attorney General alleges that the Company increased its ROE recommendations using the risk premium analysis by creating new adjustments that increase the cost of equity for the Comparison Group. Specifically, the Attorney General alleges that (1) the Company's "market-to-book" ratio adjustment inflates the DCF results by 82 basis points, and (2) the Company's leveraged beta adjustment inflates the CAPM analysis by 125 basis points, or 1.25 percent (id. at 91, citing Exh. KEDNE/PRM-1, at 40-41, 47-49). Finally, the Attorney General argues that the Company ignored what is "probably the most important single factor" that investors consider when investing in the companies in the Comparison Group, namely that these businesses have a higher required return on common equity due to the increased risk of their non-utility investments (id. at 91-92, citing Exh. AG 14-19). For these reasons, the Attorney General argues that the Department should reject the Company's risk premium analysis (id. at 91).

v. Capital Asset Pricing Model

The Attorney General argues that the Department should reject the Company's CAPM analysis, because (1) the assumptions underlying the model are sufficiently flawed so that it cannot reliably determine the cost of common equity for a utility company, and (2) the Company has applied the model poorly (id. at 85).

First, the Attorney General argues that the Department has recognized several fundamental assumptions of the CAPM do not hold true in the case of an investment in the Comparison Group companies' common stock (id. at 87, citing D.P.U. 96-50 (Phase I) at 125; D.P.U. 92-110, at 148-150; D.P.U. 92-78, at 113;D.P.U. 88-67 (Phase I) at 184; Commonwealth Electric Company, D.P.U. 956, at 54-55 (1982)). Specifically, the Attorney General states that the Department has rejected the following assumptions as too unrealistic: (1) an assumption that investors can borrow and lend unlimited amounts of money at the risk free rate; (2) an assumption that investors use the means and standard deviations of portfolio returns to evaluate equity portfolios; (3) an assumption that there are no income taxes; and (4) an assumption that a "100 percent liquidating dividend" is paid at the end of the period (id. at 87, citing D.P.U. 956, at 54-55). Because the Company's analysis does not address the fundamental problems with the unrealistic assumptions listed above, the Attorney General urges the Department to again reject the use of the CAPM as a method for determining the cost of equity for utilities.

Second, the Attorney General takes issue with the Company's specific application of the CAPM (id. at 88). The Attorney General claims that by using 20-year U.S. Treasury bonds as

a proxy for the risk free rate, the Company improperly assumes that investors have a 20-year or greater investment horizon (id., citing Exh. KEDNE/PRM-1, at 48-49). However, the Attorney General argues that investors have "infinitely many" investment horizons that will cause different return requirements. For example, assuming a five-year and a thirty-day investment horizon, the Attorney General calculates the CAPM required return at 8.93 percent and 8.30 percent, respectively (id. at 88-89, citing Exhs. AG-14-30, KEDNE-PRM-1, at 48l; RR-AG-65). In addition, the Attorney General contends that the Company inflates its ROE recommendation by adding a premium to the CAPM analysis to account for the small size of Boston Gas. The Attorney General contends that because Boston Gas is now part of Keyspan, which is both a S&P 500 company and the fifth largest gas distribution company in the United States, no additional equity risk premium is appropriate (id. at 89, n.61). For these reasons, the Attorney General argues that the Department should reject the results of the Company's analysis using the CAPM.

vi. Comparable Earnings Approach

The Attorney General agues that the Department should reject the results of the Company's comparable earnings analysis as unreliable (id. at 89-90). The Attorney General contends that the Department has repeatedly rejected this approach in general (id. at 90, citing D.P.U. 96-50 (Phase I) at 131-132; D.P.U. 92-250, at 160-161; D.P.U. 92-211, at 280-281; D.P.U. 92-210, at 155; D.P.U. 905, at 48-49). Further, the Attorney General argues that the Department has rejected the Company's specific comparable earnings approach as unreliable because the earned ROE did not necessarily equal the companies' cost of capital (id.,

citing D.P.U. 905, at 48-49; Boston Edison Company, D.P.U. 1991, at 56 (1979)). Arguing that the Company has provided no reason to change this well-founded precedent, the Attorney General argues that the Department should reject the Company's comparable earnings analysis (id. at 90).

vii. Disaggregated ROE

The Attorney General argues that the Department should disaggregate the Company's allowed ROE for purposes of cost allocation, such that residential classes are allocated a lower ROE than nonresidential classes (id. at 92; Attorney General Reply Brief at 48). The Attorney General contends that residential customers have a lower risk to serve than C&I customers (id. at 48, citing Tr. 15, at 1910; Attorney General Reply Brief at 47). Also, the Attorney General contends that residential customers have not received any benefits from the development of a competitive gas market, despite the significant benefits these customers offer the Company in the form of a stable, predictable load (Attorney General Reply Brief at 47-48, citing Bay State Gas Company, D.T.E. 01-81, at 27-28 (2002); Exh. KEDNE/AEL-5). The Attorney General argues that the Department has previously recognized differences in risk between classes (id. at 46, citing D.P.U. 95-40, at 115-116. Noting that Boston Gas' IRR threshold for mains investments is 100 basis points lower for residential construction than for other customer classes, the Attorney General requests that the Department set the ROE for the residential class 100 basis points lower than the C&I classes when determining class revenue requirements (Attorney General Brief at 92-93, citing Tr. 7, at 1813-1815; Attorney General Reply Brief at 46, 48).

b. AIM

AIM disputes the Company's contention that Boston Gas has the risk characteristics to warrant a 12.18 percent ROE (AIM Reply Brief at 3). Instead, AIM argues that in light of the Department's recent ROE determinations for Fitchburg (ten percent) and Berkshire (10.5 percent), a reasonable ROE for Boston Gas would be 10.5 percent. AIM argues that a 10.5 percent ROE would appropriately compensate the Company for its risk, while allowing the Company the credit quality needed to compete in the capital markets (id.).

c. Boston Gas

i. Introduction

Averaging the results of its risk premium and DCF analyses, the Company argues that a ROE of 12.18 percent is appropriate, fair and reasonable (Boston Gas Brief at 130-131). The Company argues that the Department has previously recognized the usefulness of the DCF and risk premium models when considering the cost of equity (id. at 130, citing D.P.U. 87-122, at 106). In addition, the Company alleges that it has recommended a conservative ROE, at the lower end of the range of the estimates produced by all four models (id. at 130).

The Company alleges that its ROE recommendation is also conservative because it does not take into account any "unforseen events" that may occur during the effective period of its proposed PBR plan (id. at 131, citing Exh. KEDNE/PRM-1, at 6). In addition, Boston Gas disputes the Attorney General's assertion that a reduction to the allowed ROE is required if the Department accepts the Company's weather stabilization proposal (id. at 206). The Company argues that absent a weather stabilization program, the Company will continue to stabilize its

earnings against weather volatility through the use of appropriate financial instruments. Therefore, Boston Gas argues that approval of its weather stabilization proposal will not change the Company's risk (id. at 205-206). Also, Boston Gas argues that investors already expect the companies in the Comparison Group to take advantage of available financial instruments to minimize weather volatility and, therefore, weather risk has been removed from consideration in a gas utility's cost of equity (id. at 206, citing Tr. 15, at 1937-1938).

The Company disputes the Attorney General's assertion that approval of its proposed pension mechanism will require a reduction in the approved ROE. First, the Company argues that its proposed pension mechanism will not reduce the risk to investors in the Company's common stock, but rather will maintain the "status quo" – i.e., traditional cost of service ratemaking where it is necessary to set a representative level of costs in rates that does not "unfairly penalize" either the Company or its customers (Boston Gas Reply Brief at 52, n.26, citing Attorney General Reply Brief at 28; Exh. KEDNE/PRM-4, at 2-3). In fact, the Company opines that if the Department were to lower the required ROE to account for approval of its proposed pension mechanism, Boston Gas' risk would actually increase as a response to the removal of a risk premium for pensions where none now exists (id., citing Tr. 13. at 1728-1734).

Second, the Company argues that because the issue is "just now emerging in the public's awareness," the market, as reflected by the Comparison Group, has not yet placed a risk premium on pension cost recovery (id. at 53, citing Exh. KEDNE/PRM-4, at 3). Therefore, if there is no risk premium associated with pension cost recovery, the Company

argues that there is no basis to remove any premium from its ROE (id.). In addition, Boston Gas argues that companies within the Comparison Group currently have in place "non-traditional mechanisms" to account for pension costs (id. at 53, citing RR-DTE-63). Finally, the Company argues that the Attorney General has provided no evidentiary support for his proposed 0.5 percent pension-related reduction in ROE (id. at 54-55, citing Attorney General Reply Brief at 28).

ii. Comparison Group

The Company argues that, on balance, its chosen Comparison Group provides a reasonable basis for measuring Boston Gas' ROE (Boston Gas Brief at 131-132). The Company argues that the overall similarity in business and credit quality risks show that the Comparison Group is comparable to Boston Gas (Boston Gas Reply Brief at 88, citing Exh. KEDNE/PRM-1, at 9-10, 18).

The Company argues that 78 percent of the Comparison Group's revenues, 96 percent of its income, and 91 percent of its identifiable assets are from the gas utility business (Boston Gas Brief at 131, n.52). Boston Gas argues that the fact that the companies in the Comparison Group have some non-utility operations, does not invalidate the proposition that the ROE for these companies is related primarily to their gas distribution businesses (Boston Gas Reply Brief at 87-88).

Boston Gas argues that "objective data" indicate that the non-utility business of the Comparison Group companies does not elevate their cost of equity (Boston Gas Reply Brief at 88). In the categories of financial risk, operating ratios, quality of earnings, and the ratio of

internally generated funds-to-construction, the Company argues that Boston Gas is similar to the Comparison Group. However, the Company argues that Boston Gas' earned returns are more variable than the Comparison Group, thereby making Boston Gas more risky overall (Boston Gas Brief at 132, citing Exh. KEDNE/PRM-1, at 19-24).

The Company disputes the Attorney General's criticisms of its statistical analysis of the variability in earned returns. Performing the statistical analysis in the manner suggested by the Attorney General (first individually computing coefficients of variation in earned returns and then averaging the individual coefficients to arrive at an average measure of variability for the Comparison Group), the Company argues that Boston Gas is still riskier than the Comparison Group (Boston Gas Reply Brief at 86-87, citing Attorney General Reply Brief at 42-43; Exhs. AG-5-1(a); KEDNE/PRM-1, at 21).

iii. Discounted Cash Flow Analysis

The Company argues that its DCF analysis is reasonable. The Company argues that it appropriately used the six-month period ending December of 2002 to arrive at the unadjusted dividend yield of 5.11 percent, as this period is reflective of current capital costs, but avoids "spot" yields (Boston Gas Brief at 133, citing Exh. KEDNE-PRM-1, at 28). The Company objects to the Attorney General's use of data for the six months ending June 2003 to calculate the unadjusted dividend yield. The Company argues that this period contains "historically low" dividend rates, and, therefore, produces an inappropriate downward bias (id. at 139, citing RR-AG-67). In addition, the Company argues that this six-month period is inconsistent with the six-month period selected by the Attorney General to establish the risk-free rate of

return (id. at 138-139, citing Tr. 15, at 1952; Boston Gas Reply Brief at 88). Because it coincides with the end period of the growth rate data cited by the Attorney General, the Company argues that a "more defensible approach" would be to use data for the six months ending April 2003, resulting in an unadjusted dividend yield average of 5.04 percent (id. at 139, citing Exhs. AG-14-18, AG-14-20).

In addition, the Company argues that it appropriately relied on forecasts of earnings-per-share data as "providing strong evidentiary support" for its prospective growth rate of six percent. The Company argues that earnings-per-share estimates by financial advisors are most indicative of the investor-expected growth for a company (id. at 133-134, citing Exh. KEDNE/PRM-1, at 30-33). Further, the Company argues that historical evidence is not a good measure of growth for the Comparison Group due to recent industry restructuring, mergers, and acquisition activities (id. at 133, n.54, citing Exh. KEDNE/PRM-1, at 32). Therefore, if the Department were to rely on a traditional DCF analysis applying historical data, the Company argues that the model would underestimate its required ROE (id. at 134, citing Exh. KEDNE/PRM-1, at 34).

The Company challenges the Attorney General's proposed four percent growth rate as without evidentiary support or theoretical justification (id. at 136). Specifically, the Company argues that the Attorney General inappropriately references the 5.5 percent estimated growth rate from its last rate case, because the proxy group of companies on which that growth rate was based is not the same Comparison Group as used in this proceeding (id.). In addition, the Company argues that there is insufficient theoretical or evidentiary foundation for the selection

of the gross domestic product to represent long-term growth in a DCF analysis (id., citing Exh. KEDNE/PRM-1, at 35).

Finally, the Company disputes the Attorney General's reliance on growth-in-dividends rather than forecasts of earnings-per-share growth to arrive at an appropriate DCF growth rate. By relying on growth-in-dividends, the Company argues that the Attorney General inappropriately chooses the lowest available growth rate, but ignores other relevant measures such as forecast earnings-per-share, book-value-per-share, and cash flow-per-share (id. at 137). Using the Attorney General's own data, the Company alleges that the appropriate growth rate is at least 5.73 percent (id. at 137-138; Boston Gas Reply Brief at 88).

The Company argues that it appropriately applied a leverage adjustment to its DCF analysis to account for the higher financial risk associated with its book value capitalization (id. at 134, citing Exh. KEDNE/PRM-1, at 38-41). The Company argues that when market prices diverge from book values, as is the case now with most utilities, a market derived ROE cannot not be applied directly to rate base in a rate setting context. Instead, the Company argues that it is necessary to adjust the market derived ROE upward to account for the utility's increased financial risk attributable to the use of book value capitalization in the ratemaking process (id. at 134-135, citing Exh. KEDNE/PRM-1, at 38-41). According to Boston Gas, economic theory shows that when book value of equity rather than market value of equity is used for ratemaking purposes, the cost of equity increases by 0.82 percent (id. at 134, citing Exh. KEDNE/PRM-1, at 38-41). Therefore, the Company argues that it is appropriate to apply a leverage adjustment of 0.82 percent (id. at 134-135).

iv. Risk Premium Analysis

The Company argues that the inputs for its risk premium analysis (the interest rate on long-term debt and an equity risk premium), including the underlying calculations and assumptions used to arrive at these inputs, are based on reliable authorities and reasonable expectations (id. at 140-141). Disputing the Attorney General's criticism to the contrary, the Company argues that its risk premium analysis is not "essentially the same" as its analysis using the CAPM (id. at 143, citing Attorney General Brief at 90). Specifically, the Company argues that its risk premium analysis directly addresses the ROE required by a regulated utility (as it is based on the S&P Public Utility Index), rather than the broader market focus of the CAPM (id. at 143). The Company also argues that, unlike the CAPM, the risk premium analysis is not limited to a measurement of systematic risk (id.).

In addition, the Company states that it has not used a "market-to-book" adjustment as suggested by the Attorney General. Rather, as with its DCF analysis, the Company states that it incorporated a leverage adjustment to recognize what it argues is the difference in financial risk between market value capital structure and book value capital structure (id. at 143-144, citing Exh. KEDNE/PRM-1, at 40).

With respect to the Attorney General's criticism that the Company failed to consider the increased risk attributable to the Comparison Group companies' ownership of non-utility businesses, Boston Gas argues that the Attorney General has failed to adequately support his claims (id. at 144). Instead, Boston Gas argues that the Comparison Group is made up of companies that are primarily regulated gas utilities in the eyes of investors. Therefore, if any

adjustments were required as suggested by the Attorney General, they would not result in any "meaningful difference" in the required ROE (id., citing Tr. 15, at 1948).

v. Capital Asset Pricing Model

The Company argues that it chose the historical and forecast yields on long-term treasury bonds as an appropriate proxy for the risk free rate to "match the longer-term horizon" associated with the ratemaking process (id. at 145). In addition, the Company argues that it appropriately applied a leveraged beta to the Comparison Group to account for the financial risk associated with a ratemaking capital structure that is measured at book value (id.). Finally, the Company argues that as the size of a firm decreases, its risk (and associated ROE) increases. Therefore, because of the relatively small market capitalization of the Comparison Group, Boston Gas argues it was necessary to adjust the results of its CAPM analysis upward to account for a "size premium" of 1.42 percent.[149] Absent this adjustment, the Company argues that the CAPM would underestimate the required ROE (id. at 146, citing Exh. KEDNE/PRM-1, at 50).

The Company counters the Attorney General's general criticism of the use of the CAPM. Specifically, the Company notes that the "efficient market hypothesis" underlies both the DCF model and the CAPM, however, the Attorney General himself advocates the use of a DCF analysis in this case (id. at 146-147, citing Attorney General Brief at 85-88). In addition,

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[149] The Company argues that the Comparison Group has an average market capitalization of $1.087 million, placing it in the sixth decile according to the size of the companies traded on the NYSE, AMEX and NASDAQ (Boston Gas Brief at 146, citing Exh. KEDNE/PRM-1, at 50).

the Company notes that all measures of ROE include assumptions that may not hold in the "real world," but this alone "does not diminish serious scholarly efforts to overcome such challenges over time" (id. at 147).

Boston Gas also disputes the Attorney General's criticisms of the Company's application of the CAPM. First, the Company notes that, despite the allegations of the Attorney General to the contrary, it did not use the yield on 20-year Treasury bonds as a proxy for the risk free-rate of return. Instead, the Company argues that it used the yields on a "broad spectrum" of Treasury notes and bonds (id., citing Exhs. KEDNE/PRM-1, at 48-49; KEDNE/PRM-2, at 21; KEDNE/PRM-3, at F-10, F-11). In addition, the Company argues that the Attorney General's reliance on a 30-day investment horizon is inconsistent with the CAPM (id. at 147, citing Exh. KEDNE/PRM-3, at F-11).

In addition to being the result of flawed assumptions, the Company argues that the CAPM results generated by the Attorney General contain inconsistencies and are established without evidentiary support. For example, Boston Gas argues that the Attorney General has not shown the basis for his proposed 7.4 percent equity risk premium when using five-year Treasury yields, nor has he provided any record support for his calculation of the 1.5 percent yield on 30-day Treasury bills (id. at 147-148, n.59).

vi. Comparable Earnings Approach

The Company argues that it has appropriately used a comparable earnings analysis to support its recommended ROE (id. at 149). Contrary to the assertions of the Attorney General, Boston Gas contends that the Department has not rejected the use of this method

outright, but rather has allowed it as corroborative evidence that a recommended ROE is reasonable (id., citing Attorney General Brief at 89-90).

The Company argues that the results of its analysis show that the ROE for non-utility companies comparable to Boston Gas is 13.90 percent -- providing appropriate corroborative support that its recommended ROE of 12.18 percent (based primarily on the DCF and risk premium models) is both reasonable and conservative (id., citing Exh. KEDNE/PRM-1, at 55). By contrast, the Company argues that its comparable earnings analysis shows that the Attorney General's recommended 8.99 percent ROE is not reasonable (id. at 149, citing Exh. KEDNE/PRM-1, at 18).

vii. Disaggregated ROE

The Company opposes the Attorney General's proposal to disaggregate the ROE by customer class, arguing that it (1) violates the Department's ratemaking policy in favor of equalized rates of return, (2) is based on an incorrect assessment of risk attributable to the residential customer class, (3) is not adequately supported by record evidence, and (4) was inappropriately raised by the Attorney General for the first time on brief (id., citing Tr. 15, at 1910; D.P.U. 88-67; Boston Gas Reply Brief at 89-90). By failing to consider evidence concerning the low-load factor for residential customers and the competition from alternative energy sources, the Company argues that the Attorney General has conducted an unbalanced assessment of the relative risk between residential and C&I customers (id. at 149-150; Boston Gas Reply Brief at 90, citing Exh. KEDNE/PRM-1, at 11; Tr. 15, at 1910). In addition Boston Gas argues that the Attorney General has taken his sole Department citation to D.P.U.

95-40 out of context (Boston Gas Reply Brief at 89-90, citing Attorney General Reply Brief at 46-47).

4. Analysis and Findings

a. Comparison Group

In our evaluation of the Comparison Group used by Boston Gas, we recognize it is neither necessary nor possible to find a group that matches the Company in every detail. D.T.E. 02-24/25, at 225; D.T.E. 99-118, at 80; D.T.E. 98-51, at 108; D.T.E. 96-50 (Phase I) at 115. Rather, we may rely on an analysis that employs valid criteria to determine which utilities will be in the comparison group, and that provides sufficient financial and operating data to discern the investment risk of the subject company versus the comparison group. D.T.E. 02-24/25, at 225; D.T.E. 99-118, at 80; D.T.E. 98-51, at 108; D.P.U. 87-59, at 68. Boston Gas' Comparison Group includes companies that have operations beyond the scope of gas distribution, which could make these companies more risky and, in turn, potentially more profitable. However, the Company has shown that, as concerns historical earnings volatility, these companies are on par with Boston Gas (Exhs. KEDNE/PRM-1, at 21; AG 5-1(a)). Other factors, such as the Comparison Group's company size, market ratios, common equity, operating ratios, coverage ratios, quality of earnings, and internally generated funds, betas, provide an acceptable basis for evaluating the relative risks of the Company. While the Company's higher coverage ratio versus that of the Comparison Group indicates that Boston Gas has a lower risk, other factors, such as the Company's smaller size and greater volatility of earnings in relation to the Comparison Group, indicate that Boston Gas may have equal or

greater risk (Exh. KEDNE/PRM-1, at 20-23). On balance, after review of the Company's financial and operating statistics in relation to the Comparison Group, the Department finds that Boston Gas is reasonably comparable to the Comparison Group relied on in this proceeding.

b. Discounted Cash Flow Analysis

In the past, the Department has addressed various forms of DCF analyses as a basis for determining an appropriate return on equity. See D.T.E. 02-24/25, at 226-228; D.P.U. 96-50 (Phase I) at 119-120; D.P.U. 95-40, at 96-97; D.P.U. 93-60, at 250-251. As indicated above, the Company-proposed DCF model postulates that the value of an asset is equal to the present value of future expected cash flows discounted at the appropriate risk-adjusted rate of return. Because the dividend yield and growth rate components of this risk-adjusted rate of return are variables that reflect investors expectations of future performance of stock investment, there will always be potential problems and limitations in estimating the appropriate values of these two variables. D.T.E. 96-50 (Phase I) at 120.

Regarding the yield component of the DCF, the Department previously has rejected those adjustments that tend to overstate the dividend yield component and, consequently, the DCF-based cost of equity. More specifically, the Department has rejected financing and market adjustments and those adjustments which could double-count the effect of the yield factor. D.P.U. 95-40, at 97; D.P.U. 93-60, at 250; D.P.U. 90-121, at 178-180. In addition, the Department has rejected the inclusion of financing and market adjustments because

investors incorporate a premium into their expected return to reflect market risks and financing costs. D.P.U. 95-40, at 97; D.P.U. 90-121, at 178-180.

In this case, Boston Gas added a 0.82 percent leverage adjustment to account for market-versus-book leverage modification (Exh. KEDNE/PRM-1, at 39-40). The Company's proposed leverage adjustment relies on a comparison between book and market capitalization, and thus contains the same defects as the Department has previously identified, including insufficient consideration of the multiplicity of factors that affect investor decisions. D.T.E. 01-56, at 105. Also, the Company's leverage adjustment is similar to the now little used price-to-book ratio method of determining a utility's cost of capital, which the Department has frequently rejected because of its failure to recognize important variables and its excessive reliance on investor perceptions of the relationship between market and book prices. D.P.U. 906, at 100-101; Eastern Edison Company, D.P.U. 837, at 49 (1982).

The Department has previously accepted the use of six-month yield data when necessary to recognize more current market experience. D.P.U. 94-50, at 459; D.P.U. 92-78, at 112. While the Company accepts the use of six-month data in principle, Boston Gas argues that the growth and dividend yield data must be from the same time period (Boston Gas Brief at 138-139). Because the yield component of the DCF model relies by definition on current or near-current data, and the growth component of the DCF model relies by definition on forecast data, there is an inevitable difference in the time periods under review for the growth and dividend rates. Therefore, there is no basis to conclude that yield and growth data must be derived from the same time period. In view of recent market conditions, the Department finds

it appropriate to place greater weight on the more recent dividend yields. Therefore, the Department finds that the Company's proposed dividend yield calculations overstate the required yield component of the DCF analysis.

Regarding the growth component of the DCF, the Department also has rejected those adjustments that tend to overstate the dividend growth. Boston Gas has relied on short-term earnings growth estimates which are in excess of long-run, consensus, growth-rate forecasts of the overall economy (Exh. AG 14-9, at 14). While it is possible that short-term earnings growth can exceed the growth of the U.S. economy as a whole, reliance on short-term data here would tend to overstate the required ROE. The Department has found that a balanced examination of growth rates must be made. D.T.E. 99-118, at 83; D.T.E. 98-51, at 120. These factors, such as growth in earnings-per-share and dividends-per-share, should be taken into consideration when determining an appropriate growth rate. D.P.U. 96-50 (Phase I) at 120; D.P.U. 93-60, at 251; D.P.U. 92-250, at 147; D.P.U. 88-135/151, at 125. In contrast, the Attorney General has relied on a variety of historical and forecast growth rates for dividends, earnings, and book value as a means to estimate investor-expected growth. Notwithstanding the limitations that must be considered in the use of forecast growth rates, the Department has recognized the value of forecast data as a conceptually appropriate measure of growth. D.P.U. 94-50, at 460; D.P.U. 88-250, at 97. Accordingly, the Department will consider a variety of growth rates in our evaluation of the Company's required ROE.

Based on the above considerations, the Department finds that the Company's DCF analysis overstates the required ROE for Boston Gas. Therefore, the Department will give limited weight to the Company's DCF analysis.

c. Risk Premium Analysis

The Department has repeatedly found that a risk premium analysis overstates the amount of company-specific risk and, therefore, overstates the cost of equity. D.T.E. 02-24/25, at 228; D.T.E. 98-51, at 126; D.P.U. 90-121, at 171; D.P.U. 88-135/151, at 125-125; D.P.U. 88-67, Phase I at 182-184. The Department has acknowledged the value of risk premium analysis as a supplemental approach to other ROE models but has accorded it, at best, limited weight in our determination of the cost of equity. D.T.E. 02-24/25, at 228; D.T.E. 99-118, at 86-87. The S&P Utility bond yield indices that Boston Gas relied upon include vertically-integrated companies whose operations are not confined to gas distribution services and are unrepresentative of the Company's risk and debt component. Additionally, the Department is not persuaded that the 1979 to 2001 data used to derive the risk premium represent a reliable indication of investment fundamentals. Because Boston Gas' risk premium analysis suffers from the same limitations previously noted by the Department, we will place limited weight on these results in determining the Company's ROE.

d. Capital Asset Pricing Model

The Department has rejected the use of the CAPM as a basis for determining a utility's cost of equity. D.P.U. 92-78, at 113; D.P.U. 88-67, Phase I at 184; D.P.U. 84-94, at 63-64. The Department has previously noted a number of limitations in the application of CAPM,

including the definition and data used to estimate the risk-free rate, and the coefficient of determination of beta. D.P.U. 93-60, at 257.

The same deficiencies in the CAPM identified in prior cases are also present here (e.g., there are no income taxes included in the calculation, a 100 percent liquidating dividend is paid at the end of the period.) In addition to these limitations, the Company's CAPM model relies on leveraged betas, which are intended to adjust the results of the analysis for market versus book valuations. As in our analysis of the leverage component of Boston Gas' DCF model, the Department finds that the use of leveraged betas in the Company's CAPM model overstates the required ROE for Boston Gas. Accordingly, we will not rely on the results of the CAPM analysis as a means of corroborating the results of Boston Gas' DCF and risk premium analyses.

e. Comparable Earnings Approach

The Company presented a comparable earnings analysis as an additional method to supplement its DCF and risk premium analyses. The comparison group of companies used in its comparable earnings approach consist of non-regulated firms, the Company has not demonstrated that the companies included in the comparison group have risk comparable to Boston Gas. In order to meet the comparability criteria enunciated by the Supreme Court in Bluefield Water Works and Improvement Company v. Public Service Commission of West Virginia, 262 U.S. 679 (1923) ("Bluefield") and Federal Power Commission v. Hope Natural Gas Company, 320 U.S. 591 (1942) ("Hope"), other risk criteria, including the nature of the business, must be evaluated carefully as the basis for selecting an appropriately comparable

group of companies. The Department notes that the companies used in the comparable earnings analysis include representatives of such industries as shipping, food processing, newspapers, advertising, restaurants, medical supplies, and machinery (Exh. AG 14-38). Also, the use of beta as a criterion in selecting the comparable group of companies is not a reliable investment risk indicator given its statistical measurement limitations. D.T.E. 01-56, at 116; D.T.E. 96-50 (Phase I) at 132. Accordingly, the Department rejects the Company's comparable earnings approach as a basis for determining Boston Gas' ROE in this case.

f. Disaggregated ROE

Boston Gas proposes to use a system-wide WACC in deriving the allocation of its revenue requirement among customer classes (Exh. KEDNE/AEL-1, at 36). Because the Company's proposed ROE is a component of the WACC, Boston Gas' cost allocations also presume an equalized ROE (Exhs. KEDNE/AEL-1, at 36; KEDNE/AEL-5, at 29-1 through 29-7). The Attorney General, however, argues that the Department should instead adopt a disaggregated ROE when determining class revenue requirements (Attorney General Brief at 92-93; Attorney General Reply Brief at 46-48).

The Department's long-standing policy regarding the allocation of class revenue requirements is that a company's total distribution costs should be allocated on the basis of equalized rates of return. D.T.E. 02-24/25, at 256; D.T.E. 01-56, at 139; D.P.U. 92-250, at 194. These equalized rates of return, by definition, include equalized ROEs.

The Attorney General has proposed that the Company's cost of equity be disaggregated such that the overall cost to serve residential rate classes include a lower cost of common

equity than the Company's C&I rate classes. As the Department has recognized, any restructuring of rates based on risk differentials between customers groups must be based on an investigation of the risks associated with serving the various customers, and not on the basis of some general rule that certain customer classes are less risky to serve than others. D.P.U. 95-40, at 116, n.58. The record evidence on this point is limited to generalized observations about the relative risk of certain customer classes over others and comparative investment hurdles (Exh. KEDNE/AEL-5; Tr. 15, at 1910; Tr. 7, at 1813-1815). Even if the Department were to reexamine its long-standing policy in this area, we would require a far greater depth of evidence than exists in this proceeding. Therefore, the Department declines to adopt a disaggregated ROE.

g. Conclusion

The standard for determining the allowed rate of return on common equity is set forth in Bluefield and Hope. According to the Bluefield and Hope standards, the Department's allowed return on common equity should preserve the Company's financial integrity, should allow it to attract capital on reasonable terms, and should be comparable to returns on investments of similar risk.

The Company has presented various financial methods such as the DCF and risk premium models in support of its calculation of an appropriate return on equity. These methods include the use of projected growth rates, current and projected interest rates, and financial statistics for Boston Gas and the comparison group. However, the use of these empirical analyses in this context is not an exact science. A number of judgments are required

in conducting a model-based ROE analysis. One looks for substantial evidence on which one may reasonably rely to base a judgment. Each level of judgment to be made contains the possibility of inherent bias and other limitations. D.T.E. 02-24/25, at 229; D.T.E. 01-56, at 117; Western Massachusetts Electric Company, D.P.U. 18731, at 59 (1977).

The record in this proceeding shows that there is a wide range of results produced by the Company and the Attorney General. Recognizing the inherent limitations in comparing the Company to publicly traded companies, the Department granted Comparison Group appropriate probative weight. We have given but limited weight to Boston Gas's DCF analysis, having found that the results are inflated. Because the risk premium model overstates Boston Gas' risk, the Department has given limited weight to the results of the Company's risk premium analysis. Finding that the CAPM overstates the required ROE for Boston Gas, we have given this analysis no weight. Finally, we have rejected the Company's comparable earnings analysis finding that the Company has not shown the required risk comparable to Boston Gas. Therefore, while the results of analytical models are useful, the Department must ultimately apply its own judgment to the evidence to determine an appropriate rate of return. We must apply to the record evidence and argument considerable judgment and agency expertise to determine the appropriate use of the empirical results. Our task is not a mechanical or model-driven exercise. D.T.E. 02-24/25, at 230; D.T.E. 01-56, at 118; D.P.U. 18731, at 59; see also Boston Edison Company v. Department of Public Utilities, 375 Mass. 1, 15 (1978).

Based on a review of the evidence presented in this case, the arguments of the parties, and the considerations set forth above, the Department finds that an allowed rate of return on common equity of 10.2 percent is within a reasonable range of rates that will preserve Boston Gas' financial integrity, will allow it to attract capital on reasonable terms, will be comparable to earnings of companies of similar risk, and is appropriate in this case. In making these findings, we have considered both qualitative and quantitative aspects of the Company's various methods for determining its proposed rate of return on equity, as well as the arguments of the parties in this proceeding. We recognize that investors' expectations of the return on their investments are significantly affected by the state of the economy as a whole, and that these expectations are much lower than they were in the Company's last rate investigation.

The record in this proceeding raises some performance questions with respect to Boston Gas' failure to conduct adequate IRR analyses, as a consistent practice, to support the economics behind its capital expenditures, a need to improve cost-containment efforts in these projects, difficulties in CRIS conversion project, and a lack of competitive bidding for outside services for rate case expense (see Sections III.B.3, III.D.3, and IV.J.3.b, above regarding plant additions, the CRIS, and rate case expense). These instances require that the return on equity should be set towards the low end of the range of reasonableness. D.T.E. 02-24/25, at 231; D.P.U. 92-250, at 161-162; cf. D.P.U. 92-78, at 115. Additionally, in the Department's determination of an appropriate ROE for Boston Gas, we have considered the changes in the Company's financial risk factors brought about by the pension reconciliation

mechanism adopted in this proceeding.[150] The Department has also evaluated the Company's relative risk under the ten-year PBR plan adopted in this proceeding. The exogenous cost recovery provisions of the PBR plan, the earnings sharing mechanism, as well as the fixed threshold at which the Company qualifies for exogenous cost recovery, offset any additional risk that may occur under a longer PBR term.

VI. COST ALLOCATION AND RATE DESIGN

A. Rate Structure Goals

Rate structure is the level and pattern of prices charged to customers for their use of utility service. Rate structure for each rate class is a function of the cost of serving that rate class. Rate structure also considers the design of the rates so that the cost to serve a rate class is recovered in the rates charged that class.

Utility rate structures must be efficient, simple, and ensure continuity of rates, fairness between rate classes, and corporate earnings stability. D.T.E. 01-56, at 134; D.T.E. 01-50, at 28; D.P.U. 96-50 (Phase I) at 133. Efficiency means that the rate structure should allow a company to recover the cost of providing the service and should provide an accurate basis for consumers' decisions about how to best fulfill their needs. The lowest-cost method of fulfilling consumers' needs should also be the lowest-cost means for society as a whole. Thus, efficiency in rate structure means setting cost-based rates that recover the cost to society of the

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150 Some ordinary level of risk associated with potential non-recovery of pension costs is eliminated by the reconciling mechanism established here. The risk is real but limited. See Boston Edison Company/Commonwealth Electric Company/Cambridge Electric Light Company/ NSTAR Gas Company, D.T.E. 03-47-A at 38-40 (2003)

consumption of resources used to produce the utility service. D.T.E. 01-56, at 135; D.T.E. 02-24/25, at 252-53.

A rate structure achieves the goal of simplicity if it is easily understood by consumers. Rate continuity means that changes to rate structure should be gradual to allow consumers to adjust their consumption patterns in response to a change in structure. Fairness means that no class of consumers should pay more than the costs of serving that class. Earnings stability means that the amount a company earns from its rates should not vary significantly over a period of one or two years. D.T.E. 01-56, at 135; D.T.E. 02-24/25, at 252-53.

There are two steps in determining rate structure: cost allocation and rate design. The cost allocation step assigns a portion of the company's total costs to each rate class in a cost of service study ("COSS"). The COSS represents the cost of serving each class at equalized rates of return given the company's level of total costs. D.T.E. 01-56, at 135; D.T.E. 01-50, at 29; D.P.U. 96-50 (Phase I) at 133.

There are four steps to develop a COSS. The first step is classify costs by category, according to the service function they provide -- either (1) production and storage or (2) transmission and distribution. The second step is to classify expenses in each functional category according to the factors underlying their causation (i.e., demand-, energy-, or customer-related). The third step is to identify the most appropriate allocator for costs in each classification within each function. D.T.E. 01-56, at 136; D.T.E. 98-51, at 132; D.P.U. 96-50 (Phase I) at 133-134. The fourth step is to allocate all of a company's costs to

each rate class based upon the cost groupings and allocators chosen, and to sum these allocations in order to determine the total costs of serving each rate class.

The results of the COSS are compared to the revenues collected in the test year. If these amounts are close, then the revenue increase or decrease may be allocated among the rate classes so as to equalize the rates of return and ensure that each rate class pays the cost of serving it. If, however, the differences between the allocated costs and the test-year revenues are great, then, for reasons of continuity, the revenue increase or decrease may be allocated so as to reduce the difference in rates of return, but not to equalize them in a single step. See D.T.E. 01-56, at 135; D.T.E. 01-50, at 29.

As the previous discussion indicates, the Department does not determine rates based solely on costs, but also explicitly considers the effect of its rate structure decisions on customers' bills. For instance, the pace at which fully cost-based rates are implemented depends in part on the effect of the changes on customers. The Department has ordered the establishment of special subsidized rate classes for certain low-income customers. In moving toward our goal of efficiency, the Department also considers the effect of such rates on low-income customers. D.T.E. 01-56, at 136; D.T.E. 01-50, at 29-30.

In order to reach fair decisions that encourage efficient utility and consumer actions, the Department's rate structure goals must balance the often divergent interests of various customer classes and prevent any class from subsidizing another unless a clear record exists to support – or statute requires, G.L. c. 164, § 1F(4)(i) – such subsidies. The Department

reaffirms its rate structure goals that result in rates that are fair and cost-based and enable customers to adjust to changes. D.T.E. 01-56, at 136-137; D.T.E. 01-50, at 30.

The second step in determining the rate structure is rate design. The level of the revenues to be generated by a given rate structure is governed by the cost allocated to each rate class in the cost allocation process. The pattern of prices in the rate structure, which produces the given level of revenues, is a function of the rate design. The rate design for a given rate class is constrained by the requirement that it should produce sufficient revenues to cover the cost of serving the given rate class and, to the extent possible, meet the Department's rate structure goals discussed above. D.T.E. 01-56, at 136-137; D.T.E. 01-50, at 30.

B. Cost Allocation

The Company performed an allocated COSS as a basis to assign or allocate costs to customer rate classes, and filed three separate COSS results (Exhs. KEDNE/AEL-1, at 20; KEDNE/AEL-5; KEDNE/AEL-6; KEDNE/AEL-8). The first study presents the allocated COSS for the total cost of service (excluding purchased gas costs, local production and storage, gas acquisition costs, and bad debt costs associated with gas costs) (Exhs. KEDNE/AEL-1, at 20; KEDNE/AEL-5). The second study presents the allocated COSS performed to determine the local production and storage costs to be removed from base rates and recovered through the CGA (Exhs. KEDNE/AEL-1, at 20; KEDNE/AEL-6). The third study sets forth the COSS performed to determine the embedded customer component used to develop the customer charges for each tariff (Exhs. KEDNE/AEL-1, at 20; KEDNE/AEL-8).

The Company states that it provided the Department with detailed testimony and supporting exhibits regarding its COSS method (Boston Gas Brief at 154, citing Exhs. KEDNE/AEL-1, at 21-36; KEDNE/AEL-4; KEDNE/AEL-5; KEDNE/AEL-6; KEDNE/AEL-7; KEDNE/AEL-8). The Company argues that, through this supporting information, it has demonstrated that its COSS properly allocates the Company's costs and revenues to customer classes, in a manner consistent with Department precedent (Boston Gas Brief at 154). Consequently, the Company avers that the Department should approve the Company's COSS (Boston Gas Brief at 154-155). No other party commented on the Company's proposed allocated COSS.

The Department has evaluated the Company's proposed COSS and finds that they are consistent with Department precedent for cost allocation. D.T.E. 01-56, at 138; D.P.U. 96-50 (Phase I) at 136. The Department directs the Company, in its compliance filing, to re-run its COSS to allocate costs and expenses consistent with this Order.

C. Local Production and Storage Costs

1. Introduction

The Company proposes to allocate 100 percent of local production and storage costs to the cost of gas adjustment ("CGA") because the Company claims that these facilities are no longer used to support distribution-system integrity (Exh. KEDNE/ALS-1, at 22). Boston Gas further claims that because of changes in the availability of new pipeline supplies and the enhanced reinforcement of its distribution system, the Company's local production and storage

facilities are now used entirely for gas supply and peak- shaving purposes (Exh. KEDNE/ALS-1, at 22).

In order to remove the costs associated with these facilities from base rates, the Company conducted an unbundled cost-allocation study to determine the revenue requirement associated with its local production and storage facilities (Exh. KEDNE/ALS-1, at 22). This amount ($14,052,000) was deducted from the total revenue requirement to be billed through base rates and will be included in the GAF calculation (Exhs. KEDNE/ALS-1, at 22; KEDNE/AEL-6, at 29-1, ln. 16).

In support of the Company's contention that the local production and storage facilities are no longer used to support distribution-system integrity, it provided outputs from Boston Gas' distribution system model (Exh. DTE 2-11). This model tests the ability of the distribution system to operate without support from the local production and storage facilities (id.). In addition, the Company identified which facilities were dispatched during the test year, assuming 42 heating degree days,[151] and what percent of total sendout was represented by those facilities that were dispatched (RR-DTE-12; RR-DTE-87). The record indicates that the Commercial Point facility was dispatched two days during the test year (RR-DTE-87). On March 4, 2002, the Commercial Point sendout was 1.9 percent of the Company's total sendout for that day (id.). On December 4, 2002, the Commercial Point sendout was 6.2 percent of

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[151] Forty-two heating degree days is the highest degree day level before liquified natural gas or propane is required for gas supply purposes (Exh. DTE 2-11).

the Company's total sendout for that day (RR-DTE-87). No parties commented on the Company's proposed treatment of local production and storage costs.

2. Analysis and Findings

In D.P.U. 96-50 (Phase I) at 150, the Department directed Boston Gas to recover 15 percent of the costs of local production and storage facilities through base rates and the remaining 85 percent through the CGA. The Department also noted that as the post-FERC Order 636,[152] 636-A,[153] and 636-B[154] environment evolves, the gas market could provide increasing levels and varieties of services and opportunities for matching supply and demand both at the LDC's city-gate and at the customer's burner-tip. D.P.U. 96-50 (Phase I) at 149. Consequently, the Department recognized that the issue of recovering a portion of the costs of local production and storage facilities through base rates may eventually cease to exist. Id.

In the instant proceeding, the Company has proposed to recover all costs of local production and storage facilities through the GAF. However, the evidence clearly indicates that local production and storage facilities were used to support the Company's distribution system during the test year (RR-DTE-87). Accordingly, the Department directs the Company to recover 6.2 percent of the costs of local production and storage facilities through the base

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152 Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation and Regulation of Natural Gas Pipelines after Partial Wellhead Decontrol, FERC Order No. 636, 57 Fed. Reg. 13,267 (April 16, 1992), III FERC Stats. and Regs. Preambles ¶ 30,939 (April 8, 1992).

153 57 Fed. Reg. 36,128 (August 12, 1992), III FERC Stats. and Regs. Preambles ¶ 30,950 (August 3, 1992).

154 57 Fed. Reg. 57,911 (December 8, 1992), 61 FERC ¶ 61,272.

rates and the remaining 93.8 percent through the CGA. The Department directs Boston Gas in its compliance filing to design rates consistent with this Order.[155]

D. Marginal Costs

1. Introduction

The marginal cost study ("MCS") is designed to estimate the increased non-gas costs that the Company would incur if it were to expand its services through the addition of distribution capacity, the addition of customers, or the increased throughput of natural gas (Exh. KEDNE/ALS-1, at 4). The use of the MCS in setting rates results in a level and pattern of prices that promotes appropriate consumption decisions as well as an efficient allocation of societal resources (id. at 5-6).

According to Boston Gas, marginal capacity costs are the long-run variable costs that the Company would incur to meet increased demands on its system capacity during peak periods (id. at 4). The MCS also analyzes the costs that would be incurred by adding an additional customer to the Company's distribution system (id.). Finally, the MCS analyzes the costs to serve an additional unit of throughput (id.). The Company developed marginal costs for (1) distribution system capacity costs, and (2) customer costs (id. at 8-16).

Regarding distribution system capacity costs, the Company first determined the long-run cost of upgrading or reinforcing its existing transmission and distribution system (id. at 8).

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155 The 93.8/6.2 percent split between the CGA and base rates approved in this Order results in a $951,150 (0.062 times $15,324,998) increase in the costs of local production and storage facilities to be recovered in base rates (Exh. KEDNE/PJM-2, at 21). The final adjustment will be based upon the Company's compliance allocated COSS.

The Company used the prospective additions method, which developed an estimate of the anticipated unit cost of reinforcing the existing distribution system to meet future growth (id.; Tr. 4, at 427-429). In using the prospective additions method, the Company employed four years of historical reinforcement footage load and cost data (Exh. KEDNE/ALS-1, at 8). The analysis computed a long-run reinforcement cost of $142.17 per design day MMBtu (id. at 9).

Second, the Company used the prospective additions method to develop an estimate of the long-run cost of growth-related main additions (id. at 8-9). This analysis computed a long-run cost of growth-related main additions of $356.98 per design day MMBtu (id. at 9). The marginal costs attributable to system reinforcement and new main additions totaled to $499.15 per design day MMBtu (id. at 10).

Third, the Company determined the operations and maintenance ("O&M") expenses associated with capacity-related production (id. at 10-11). The Company both performed a regression analysis of adjusted expense dollars against design-day sendout, trended over 26 years, and calculated the long-run average cost (id. at 11). Because the regression analysis was not, in Boston Gas' opinion, sufficiently robust, the Company relied on a long-run average cost, which it determined to be $0.83 per design day MMBtu (Tr. 4, at 437).

Fourth, the Company determined the distribution capacity-related O&M costs, by both performing a regression analysis and calculating the long-run average cost (Exh. KEDNE/ALS-1, at 3). Again the regression analyses were not sufficiently robust, so the Company used the long-run average cost of $41.45 per design day MMBtu (Exh. KEDNE/ALS-2, Sch. 4, at 1). Last, the Company added an allowance for working

capital of $5.71 per design day MMBtu and adjusted the costs by loading factors to determine a total marginal distribution capacity cost of $136.12 per design day MMBtu (Exh. KEDNE/ALS-2, Sch. 8, at 1).

The marginal costs of serving an additional customer are a function of the size of the customer and the class of service (Exh. KEDNE/ALS-1, at 6). The Company's marginal customer costs consist of (1) plant investment in services and meters, (2) related O&M expenses, and (3) billing costs such as customer accounting and customer information expenses (id. at 13).

Boston Gas computed the customer-related plant investment by using current engineering estimates to compute the average replacement costs for each customer class (id.). Through the use of the long-run average cost, the Company computed the customer-related O&M incremental expenses, which include accounting, marketing and uncollectible expense (id. at 14). The final step in the Company's analysis was to derive loading factors that represent administrative and other indirect costs and sum the various expenses (id. at 14-15).

Boston Gas contends that its MCS was developed using the method approved by the Department in D.P.U. 96-50 and in the Company's prior rate proceeding, D.P.U. 93-60 (Boston Gas Brief at 155). Pursuant to a request by the Department, the Company attempted to remodel the Company's MCS using new regression analyses (Boston Gas Brief at 158, citing RR-DTE-55; Tr. 14, at 1761). The Company argues that the results of the remodeled MCS are not useful for rate design purposes because one of several unacceptable results applied to each of the equations used in the remodeled MCS (Boston Gas Brief at 158).

According to the Company, these unacceptable results included the following: (1) negative marginal costs estimates; (2) poor statistical results; (3) inconsistent results; (4) estimates too high to be considered for rate design; and (5) results too inconsistent between the class estimates for marginal costs to be useful for rate design (RR-DTE-55; Tr. 24, at 3279). Accordingly, the Company requests that the Department find that the Company's MCS accurately represents the Company's marginal costs and was derived in a manner consistent with Department precedent (Boston Gas Brief at 158). No other party commented on this issue.

2. Analysis and Findings

In D.T.E. 02-24/25, at 243-245, the Department approved Fitchburg's MCS, but noted that in the future, improvements had to be made to marginal cost studies to yield more reviewable and dependable results. In particular, the Department indicated that (1) the econometric analysis must be improved in terms of data included, techniques employed, and standards used to evaluate the success of relevant statistical analyses, (2) multiple variable regression equations must be used as opposed to single variable equations, and (3) an analysis must be performed to check the theoretical consistency of the marginal cost model being used. Id. Finally, the Department indicated that the aforementioned improvements to the MCS have "applicability to gas and electric companies that is broader than Fitchburg's next rate case." Id. at 245. Boston Gas' MCS in this case did not incorporate the Department's required modifications (Tr. 4, at 471-472).

In response to a Department request, the Company recalculated marginal costs using new regression analyses in an attempt to address the concerns raised in D.T.E. 02-24/25 (RR-DTE-91).[156] The Department has evaluated the Company's revised estimation of marginal costs using regression analyses and conclude that we can not rely on the results. We are concerned with the reliability of the data and with the modeling and statistical techniques used in the analyses. In particular, the Department notes that (1) there is a drastic and unexplained upward change in the C&I throughput beginning in 1992,[157] (2) only distribution plant is considered in the analysis as expense category, and (3) some regression equations present statistical problems.[158]

In its next rate case, the Company must provide a marginal cost analysis consistent with the directives specified in D.T.E. 02-25/25 at 242-245. We reiterate that this directive applies to all gas and electric distribution companies. Additionally, for all future marginal cost analyses, the following improvements must be made to yield more reviewable and dependable

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156 Record request DTE-91 is a refinement of the MCS included in record request DTE-55.

157 For example, the data used by the Company show that there is a gradual increase in the use per C&I customer for the period 1977 through 1992 (from 653.18 MMBtu to 769.27 MMBtu) and a drastic increase in the use per C&I customer for the period 1992 through 2002 (from 769.27 MMBtu to 1760.87 MMBtu) (RR-DTE-91, Att. (b)). However, there is only a gradual increase in the number of C&I customers over the entire period from 1977 to 2002 (32,202 customers in 1977, 39,322 customers in 1992, and 44,787 customers in 2002) (id.).

158 Although the Company tested for and corrected serial autocorrelation in the residuals of each equation using the appropriate test and method, there are still some regression equations in which serial autocorrelation was not eliminated (RR-DTE-91, Att.(b) at 1, 3). In addition, some variables with no explanatory power were kept in the final regression model (RR-DTE-91, Att.(b) at 3, 4, 6, 7, 8, 10, 12, 14).

results.[159] First, a company must use reliable data. Further, whenever throughput or number of customers is used as an explanatory variable in the regression analyses, throughput must be calculated as total throughput minus interruptible sales and interruptible transportation. Likewise, number of customers must be equal to total customers minus interruptible sales customers as well as interruptible transportation customers. Second, the Company must estimate the marginal cost of all the expense categories and not only the marginal distribution plant cost. These expense categories would include distribution capacity cost, capacity-related production expenses, capacity-related transmission and distribution expenses, customer-related operating expenses, customer accounting expenses, administrative and general loading factors, and miscellaneous loading factors.

Even though Boston Gas failed to make the necessary improvements to its MCS to produce more reviewable and dependable results, the Department will accept the Company's MCS in this case. However, the Department uses the results of MCS to evaluate the cost effectiveness of any special contracts filed by the Company. That is, as part of our evaluation of these contracts, the Company must demonstrate that service under a special contract is priced above the Company's marginal distribution costs. Therefore, it is critical that we have appropriate marginal cost information to evaluate the special contracts. The Company indicated that Boston Gas can conduct a MCS incorporating our required modifications in three

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[159] Other required improvements may be added in later rate cases. These additions will also be required of the Company in its next rate cases and of other gas and electric distribution companies, too.

to six months (RR-DTE-91). We, therefore, direct the Company to file for Department review a complete MCS no later than six months after the date of issuance of this Order.

E. Rate Design

1. Introduction

Based on the results of the Company's COSS, no rate class is currently collecting its full embedded customer cost through its customer charge (Exh. KEDNE/ALS-1, at 20). According to the Company, each rate class' current customer charge is so far below its embedded costs that the Company is not able both to set the customer charges to collect embedded cost and at the same time to satisfy the Department's continuity goal (Exh. KEDNE/ALS-1, at 20). Accordingly, to reduce intra-class subsidies and satisfy the Department's rate design goals, the Company proposes to phase in cost-based customer charges (Exh. KEDNE/ALS-1, at 20). As part of this phase-in process, the Company proposes to increase each rate class' customer charge by one-third of the difference between the current customer charge and the fully embedded cost (Exhs. KEDNE/ALS-1, at 24; AG 23-20).

In regards to the delivery charges, the Company proposes to simplify its rate structure where possible, by establishing single-step volumetric charges (Exh. KEDNE/ALS-1, at 21). However, where it is not possible, as a result of a large portion of customer costs not being recovered through the customer charge, the Company proposes to establish a block rate that does not distort the price signal of the tailblock rate (Exh. KEDNE/ALS-1, at 21).

To promote efficiency, the Company proposes to set the peak period tailblock rates at the marginal distribution cost (Exh. KEDNE/ALS-1, at 21). In order to enhance the

Department's goal of earnings stability, the Company proposes to set the off-peak tailblock rates such that they collect a level of margins in the off-peak period (Exh. KEDNE/ALS-1, at 21). The Company proposes to set the break between headblock and tailblock rates at a level that results in the usage on approximately 50 percent of customer bills terminating in the headblock and 50 percent in the tailblock (Exh. KEDNE/ALS-1, at 21).

Because of continuity concerns, the Company proposes to move $10,000 from the cost to serve Rate G-17 to Rate R-3 (Exh. DTE 4-9, at 3). Also, because of continuity concerns, the Company proposes to remove $800,000 from the cost to serve Rate G-54 and collect $300,000 of it from Rate G-43 and the remaining $500,000 from Rate G-53 (Exh. DTE 4-9, at 3). Also, the Company proposes to allocate the shortfall from providing low-income discount rates to all rate classes based on the class' allocated share of rate base (Exh. KEDNE/ALS-1, at 21). Last, the Company proposes to limit the increase to all rate classes on average to no more than ten percent as compared to the customer's 2002 total bill (Exh. KEDNE/JFB-1, at 3).

2. Positions of the Parties

a. Attorney General

The Attorney General contends that the Company's proposed customer charges violate the Department's rate continuity goal for the majority of customers, because they would result in significantly higher bills for low-use customers (Attorney General Brief at 104-105). The Attorney General argues that the Department should direct the Company to set the customer charge for each rate class at a level that is below the embedded customer costs and direct the

Company to recover the remaining class revenue requirement through the delivery charge (Attorney General Brief at 105). Therefore, the Attorney General states that, in an effort to control bill impacts at a time when customers are already paying for large increases in the GAF, the Department should reject the Company's proposal for increasing the customer charges and allow, similar to D.P.U. 96-50, only a small increase in residential and small commercial ratepayers' customer charges (Attorney General Brief at 106).

In addition, the Attorney General asserts that the Department should order the Company to provide, in its compliance filing, justification for the continued use of its rate design model and proof that it has corrected errors in the low-income billing determinants (Attorney General Brief at 98). According to the Attorney General, the Company initially filed its proposed rates using a rate design model that included a cell reference error (Attorney General Brief at 99, citing KEDNE/ALS-8 at 2). Moreover, the Attorney General states that the Company also admitted that there was another cell reference error contained in the rate design related to the Company's method of computing the low-income classes billing determinants, which are used to determine the distribution rates (Attorney General Brief at 99, citing RR-AG-17). Because of this cell reference error the class rates were higher than if their bill determinants had been at the correct levels because these rates were being designed to recover their revenue requirement over fewer billing units (Attorney General Brief at 100).

The Attorney General argues that the low-income bill determinant error is serious (Attorney General Brief at 100). The Attorney General contends that if the error had not been corrected, the Company would have overcharged customers approximately $4.0 million

annually (Attorney General Brief at 100). Further, the Attorney General contends that this error amount would have been compounded each year by any annual PBR formula and could have produced a windfall to the Company of over $25 million during a five year PBR period, assuming an annual PBR increase of three percent and a two percent annual load growth (Attorney General Brief at 100). The Attorney General accepts that errors can occur, but argues that the Department should not allow a pattern of repeated errors within the same model (Attorney General Brief at 101). The Attorney General asserts that the Company's proposed rate design must be based on an accurate and reliable model (Attorney General Brief at 101). Therefore, the Attorney General requests that the Department order the Company to provide evidence that demonstrates that the Company's rate design models are accurate and that the Company rigorously reviews and validates its proposals (Attorney General Brief at 101). In addition, the Attorney General argues that the Department should require the Company to provide in its compliance filing sufficient support for the continued use of its rate design model, proof that the low income bill determinants are valid (as was requested in RR-AG-17), and all proofs and tests it has done to validate these results (Attorney General Brief at 101).

The Attorney General also argues that the Company exaggerates the benefits of its rate impact mitigation proposal (Attorney General Reply Brief at 52). He states that this proposal, which states that the Company will limit the impact of any base rate increase to no more than ten percent for the average customer in each rate class as compared to the 2002 bill, are insufficient to protect customers (Attorney General Reply Brief at 52). The Attorney General asserts that the Company did not provide any specific information about its rate cap proposal

and, therefore, the Department cannot evaluate the impact on ratepayers (Attorney General Reply Brief at 52). According to the Attorney General, the average customers' rates would only be realized if there is no increase in the CGA over the average CGA which would result in much higher bill impacts than ten percent (Attorney General Reply Brief at 52).

b. Boston Gas

The Company contends that its proposed rates are designed in a manner that is consistent with Department precedent (Boston Gas Brief at 150-151, citing D.P.U. 96-50 (Phase I) at 133-136; D.P.U. 93-60, at 331-332; D.P.U. 92-78, at 116). The Company states that its efforts to address continuity concerns are evidenced by (1) the Company's decision to increase the customer charges by only one-third of the difference between the fully embedded customer charge and the current customer charge and (2) shifting revenues for the residential heating rate class from the off-peak to the peak to ensure that the peak charges were higher than the off-peak, and shifting revenues from larger commercial classes to smaller commercial classes to ensure that rates for classes with large customers were lower than those with smaller customers (Boston Gas Brief at 159, n.70). Further, the Company states that it is committed to implementing a ten percent cap on rate increases for residential customers during the first year of the rate plan (Boston Gas Brief at 159, n.70).

3. Analysis and Findings

Regarding the proper level to set the customer charge and delivery charges for each rate class, the Department will make this determination on a rate class by rate class basis, based on

a balancing of our rate design goals, which are discussed above. The rate by rate analysis is discussed below.[160]

As an initial matter, the Department notes that two errors were discovered during the course of this proceeding that required the Company to rerun its rate design model and file revised rates. The Company recorded an incorrect number of residential heating customers in the peak period in its rate design model (zero instead of the correct figure of 1,900,677) (Boston Gas letter to the Department dated May 2, 2003). This error caused the cost to serve the residential heating class to be overstated by $32,267,161 (id.). Had this error not been corrected and the Company's total request been granted, the residential heating class would have received on average a 20.5 percent increase in their cost for gas service, rather than the corrected amount of ten percent (id.).

In the second error, the Company through its rate design model, divided the total number of low-income customers by six instead of twelve, because it thought it was dealing with peak determinants rather than annual determinants (Tr. 24, at 3232). This error resulted in the Company initially requesting to recover an approximate $8.0 million dollar shortfall rather than the correct shortfall amount of approximately $4.0 million (Tr. 24, at 3235-3236). If this error was not discovered, it had the potential to cause Boston Gas to over recover its cost to serve by approximately $4.0 million.

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160 The Department agrees with the Attorney General that the Company's proposed ten percent cap provides little protection to customers and as such we will give it little weight in determining the rate design.

The Company stated that the second error occurred, in part, because two people were working on the rate design file at the same time (Tr. 24, at 3234). The Company explained that they had initially discovered the error early on in the rate design process. However, because two people were working on the file simultaneously, the corrected version was never saved and submitted to the Department. To prevent such errors in the future, the Company has established a new policy where one person at a time works on a file and files are labeled to indicate which is the latest version (Tr. 24, at 3235).

Although the two errors were discovered and corrected, and the Company has taken some measures to prevent such errors going forward, the Department needs further assurance that the Company's rate design model is free of additional errors and that the Company has taken the proper measures to prevent such errors in the future. Accordingly, in the compliance for this proceeding, we direct the Company to file (1) adequate documentation ensuring that the billing determinants used in its rate design model are correct, and (2) a detailed description of all measures the Company has implemented to date, and further measures the Company plans to implement, to prevent such errors in the future.

The Department's long-standing policy regarding the allocation of class revenue requirements is that a company's total distribution costs should be allocated on the basis of equalized rates of return. See D.T.E.01-56, at 139; D.P.U. 92-210, at 214; D.P.U. 92-250, at 194; D.T.E. 02-24/25, at 256. This allocation method satisfies the Department's rate structure goal of fairness. However, the Department must balance its goal of fairness with its goal of continuity. To do this, we have reviewed the changes in total revenue requirements by

rate class and the annual and seasonal bill impacts by consumption level within rate classes. Thus, to address interclass subsidization, no rate class shall receive an increase greater than 125 percent of the overall distribution rate increase approved in this Order, excluding the allocation of the low income shortfall.

The remaining revenue increase (i.e., the amount above the 125 percent cap) will be allocated first to those rate classes that would at equalized rates of return, receive a rate decrease, but only up to the amount that would eliminate such rate decrease. The allocation will be based on the ratio of each class' decrease to the total decrease for these classes. Any remaining revenue increase, will be recovered on a pro rata basis based on current revenues, from those classes whose revenue requirement falls below the 125 percent rate cap and who at equalized rates of return would not receive a rate decrease.

Last, the Department finds that allocating the low-income shortfall using a rate base allocator to all rate classes is consistent with Department precedent. D.T.E. 01-56, at 146; D.T.E. 01-50, at 35; D.P.U. 96-50 (Phase I) at 158. Therefore, the Department directs the Company, in its compliance filing, to collect the low-income shortfall from all rate classes using a rate base allocator.

F. Rate by Rate Analysis

1. Rate R-1 and Rate R-3 (Residential Non-Heating and Heating)

a. Introduction

Rate R-1 is available to all residential customers who do not have gas space-heating equipment, while Rate R-3 is available to all residential customers who have gas space-heating equipment. Both R-1 and R-3 require that a customer take service through one meter in a single building that contains no more than four dwelling units (Exh. KEDNE/ALS-7 [rev.] at 1). The Company proposed to increase the monthly customer charge from $8.48 to $10.45 for Rate R-1, and from $10.07 to $16.98 for Rate R-3 (Exh. KEDNE/ALS-5 [rev.] at 1)

The proposed R-1 delivery charge during the peak season is $0.6664 per therm for the first 20 therms consumed, and $0.1438 for each additional therm (Exh. KEDNE/ALS-7 [rev.] at 1). The proposed R-1 delivery charge during the off-peak season is $0.6664 per therm for the first ten therms consumed, and $0.1438 for each additional therm consumed (Exh. KEDNE/ALS-7 [rev.] at 1).

The proposed R-3 delivery charge during the peak season is $0.3996 per therm for the first 150 therms consumed, and $0.1974 for each additional therm consumed (Exh. KEDNE/ALS-7 [rev.] at 5). The proposed R-3 delivery charge during the off-peak season is $0.3996 for the first 30 therms consumed, and $0.1974 for each additional therm consumed (Exh. KEDNE/ALS-7 [rev.] at 5). Also, to bring the peak and off-peak headblock charges together, the Company proposed to shift $8.04 million from the off-peak period to the peak period where it is spread over larger peak-period volumes (Exh. KEDNE/ALS-1, at 25).

b. Analysis and Findings

According to the Company's MCS, the total peak season marginal costs for Rates R-1 and R-3 are $0.1438 and $0.1974 per therm, respectively (Exh. KEDNE/ALS-2, Sch. 11, at 1). According to the Company's COSS, the embedded customer charge for Rates R-1 and R-3 are $14.38 and $30.79 per month, respectively (Exh. KEDNE/AEL-8, at 29). Based on a review of marginal and embedded costs and the seasonal and annual bill impacts on customers, the Department finds that an R-1 Rate, designed with a $9.50 monthly customer charge for the peak and off-peak seasons and a $0.1438 tailblock rate for both the peak and off-peak seasons, satisfies continuity goals and produces bill impacts that are moderate and reasonable. Based on the R-3 marginal and embedded costs and seasonal and annual bill impacts, the Department finds that a $12.00 monthly customer charge for the peak and off-peak seasons and a $0.1974 tailblock rate for both the peak and off-peak seasons, satisfies continuity goals and produces bill impacts that are moderate and reasonable. In addition, for Rates R-1 and R-3, respectively, the Company is directed to shift revenues between seasons so as to price both the peak and off-peak headblock charges at the same rate.

Therefore, the Department directs the Company to set the R-1 and R-3 charges as follows. For Rate R-1, the Department directs the Company to set the breakpoints between headblock and tailblock rates at 20 and ten therms in the peak and off-peak seasons, respectively, and to set the seasonal headblock rates at the same charge for each season to collect the remaining class revenue responsibility as specified on Schedule 10. For Rate R-3, the Department directs the Company to set the breakpoints between headblock and tailblock

rates at 150 and 30 therms in the peak and off-peak seasons, respectively, and to set the seasonal headblock rates at the same charge for each season so as to collect the remaining class revenue responsibility as specified on Schedule 10.

2. Rate R-2 and Rate R-4 (Residential Non-Heating and Heating Subsidized Rates)

Subsidized rates are available for all domestic purposes in individual private dwellings or in individual apartments. Eligibility for this rate is established upon verification of a customer's receipt of any means-tested public benefit program or verification of eligibility for the low-income home energy assistance program, or its successor program, for which eligibility does not exceed 200 percent of the federal poverty level based on a household's gross income, or other criteria approved by the Department (Exh. KEDNE/ALS-7 [rev.] at 7). The Company proposes that customers on Rates R-2 and R-4 continue to receive a 40 percent discount off the delivery service charges for Rates R-1 and R-3, respectively (Exh. KEDNE/ALS-1, at 23).

The Department finds that maintaining the low-income discount at 40 percent is appropriate, because it is consistent with the discount level approved in D.P.U. 96-50. Accordingly, the Department directs the Company to set the discount rate at 40 percent.

3. Rate G-41 (C&I Low Use, Low Load Factor)

The G-41 rate is available to C&I customers whose maximum hourly meter capacity is between zero and 500 cubic feet per hour and whose metered use in the most recent peak period of November through April is greater than or equal to 70 percent of the metered use for

the most recent twelve consecutive months of September through August (Exh. KEDNE/ALS-7 [rev.] at 9). The Company proposes to increase the monthly customer charge from $23.33 to $33.55 (Exhs. KEDNE/ALS-1, at 26; KEDNE/ALS-7 [rev.] at 9). The proposed delivery charge during the peak season is $0.3769 per therm, and the proposed delivery charge during the off-peak season is $0.3241 per therm (Exh. KEDNE/ALS-7 [rev.] at 9). Finally, the Company proposes to move $1.65 million from the off-peak to the peak period to enable it to design a single step delivery charge that will provide a proper price signal (Exh. KEDNE/ALS-1, at 26).

According to the Company's MCS, the total peak season marginal cost for Rate G-41 is $0.2117 per therm (Exh. KEDNE/ALS-2, Sch. 11). According to the Company's COSS, the embedded customer charge for Rate G-41 is $54.00 per month (Exh. KEDNE/AEL-8, at 29). Accordingly, based on a review of marginal and embedded costs and the seasonal and annual bill impacts on customers, the Department finds that a rate designed with a $25.00 monthly customer charge and a single step delivery charge for the peak and off-peak seasons, satisfies continuity goals and produces bill impacts that are moderate and reasonable. In addition, to price the peak delivery charge at a higher rate than the off-peak delivery charge, the Company is directed to shift revenues such that the same ratio of peak to off-peak delivery charges proposed by the Company is maintained.

Therefore, the Department directs the Company to set the Rate G-41 charges accordingly. The Department also directs the Company to collect in the delivery charge the remaining class revenue responsibility as specified on Schedule 10.

4. Rate G-42 (C&I Medium Use, Low Load Factor)

The G-42 rate is available to C&I customers whose maximum hourly meter capacity is between 501 and 1,500 cubic feet per hour and whose metered use in the most recent peak period of November through April is greater than or equal to 70 percent of the metered use for the most recent twelve consecutive months of September through August (Exh. KEDNE/ALS-7 [rev.] at 10). The Company proposes to increase the monthly customer charge from $40.83 to $57.58 (Exhs. KEDNE/ALS-1, at 26; KEDNE/ALS-7 [rev.] at 10). The proposed delivery charge for all therms consumed during the peak season is $0.2459 per therm, and during the off-peak season is $0.2351 per therm (Exh. KEDNE/ALS-7 [rev.] at 10).

According to the Company's MCS, the total peak season marginal cost for Rate G-42 is $0.2022 per therm (Exh. KEDNE/ALS-2, Sch. 11). According to the Company's COSS, the embedded customer charge for Rate G-42 is $91.08 per month (Exh. KEDNE/AEL-8, at 29). Accordingly, based on a review of marginal and embedded costs, and the seasonal and annual bill impacts on customers, the Department finds that a rate designed with a $45.00 monthly customer charge and a single step delivery charge for the peak and off-peak seasons, satisfies continuity goals and produces bill impacts that are moderate and reasonable. In addition, to price the peak delivery charge at a higher rate than the off-peak delivery charge, the Company is directed to shift revenues such that the same ratio of peak to off-peak delivery charges proposed by the Company is maintained.

Therefore, the Department directs the Company to set the Rate G-42 charges accordingly. The Department also directs the Company to collect in the delivery charge the remaining class revenue responsibility as specified on Schedule 10.

5. Rate G-43 (C&I High Use, Low Load Factor)

The G-43 rate is available to C&I customers whose maximum hourly meter capacity is between 1,501 and 12,000 cubic feet per hour and whose metered use in the most recent peak period of November through April is greater than or equal to 70 percent of the metered use for the most recent twelve consecutive months of September through August (Exh. KEDNE/ALS-7 [rev.] at 11). The Company proposes to increase the monthly customer charge from $116.75 to $139.28 (Exhs. KEDNE/ALS-1, at 26; KEDNE/ALS-7 [rev.] at 11). The proposed delivery charge during the peak season is $0.2022 per therm for all therms consumed (Exh. KEDNE/ALS-7 [rev.] at 11). The proposed delivery charge during the off-peak season is $0.1792 per therm for all therms consumed (Exh. KEDNE/ALS-7 [rev.] at 11).

According to the Company's MCS, the total peak season marginal cost for Rate G-43 is $0.1865 per therm (Exh. KEDNE/ALS-2, Sch. 11). According to the Company's COSS, the embedded customer charge for Rate G-43 is $184.33 per month (Exh. KEDNE/AEL-8, at 29). Accordingly, based on a review of marginal and embedded costs, and the seasonal and annual bill impacts on customers, the Department finds that a rate designed with a $127.00 monthly customer charge and a single step delivery charge for the peak and off-peak seasons, satisfies continuity goals and produces bill impacts that are moderate and reasonable. In addition, to

price the peak delivery charge at a higher rate than the off-peak delivery charge, the Company is directed to shift revenues such that the same ratio of peak to off-peak delivery charges proposed by the Company is maintained.

Therefore, the Department directs the Company to set the Rate G-43 charges accordingly. The Department also directs the Company to collect in the delivery charge the remaining class revenue responsibility as specified on Schedule 10.

6. Rate G-44 (C&I Extra-High Use, Low Load Factor)

a. Introduction

The G-44 rate is available to C&I customers whose maximum hourly meter capacity is greater than 12,000 cubic feet per hour and whose metered use in the most recent peak period of November through April is greater than or equal to 70 percent of the metered use for the most recent twelve consecutive months of September through August (Exh. KEDNE/ALS-7 [rev.] at 12). Currently, the G-44 class rate structure is based on a customer charge and an estimated maximum demand charge (Exh. KEDNE/ALS-1, at 27).

The Company proposes to return Rate G-44 to a volumetric billing basis (Exh. KEDNE/ALS-1, at 27-28). In addition, the Company proposes to (1) increase the monthly customer charge from $478.73.00 to $548.67 (Exh. KEDNE/ALS-1, at 27; KEDNE/ALS-7 [rev.] at 12), (2) set the delivery charge for the peak season at $0.1969 per therm for all therms consumed, and (3) set the delivery charge for the off-peak season at $0.1779 per therm for all therms consumed (Exh. KEDNE/ALS-7 [rev.] at 12).

b. Positions of the Parties

i. MDFA

The MDFA asserts that if the Department allows the Company to change Rate G-44 from a demand rate to a volumetric rate, then the MDFA's ability to carry out its legislative mandate of promoting economic development would be negatively affected (MDFA Brief at 2).[161] Therefore, the MDFA urges the Department to reject the Company's proposed rate redesign for the G-44 rate class (id.).

In addition, the MDFA contends that the Company's proposed rate design will cause substantial rate increases through an increase to the customer charge of approximately $60 per month coupled with a nearly flat per therm charge between peak and off-peak periods (id.). Also, the MDFA argues that the Company's proposal does not meet the Department's rate design principles, which state that a redesign must ensure: that rates are efficient and simple, that there be continuity of rates and fairness between rate classes, and that corporate earnings be stable (id. at 2-3). Moreover, the MDFA asserts that the Company's commitment to limit rate increases, on a total bill basis, for residential customers to ten percent shifts more revenue to be recovered from the C&I rate classes (id. at 3). The MDFA asserts that the proposed rates violate the Department's rate continuity guidelines because all 380 G-44 customers would experience an increase of greater than ten percent (id.). Therefore, the MDFA requests that

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[161] MDFA is a quasi-public real estate economic development agency tasked with stimulating economic investment across Massachusetts (MDFA Brief at 1). MDFA manages the Devens Regional Enterprise Zone, formerly the United States Army New England headquarters, and provides under Chapter 498 of the Acts of 1998, a variety of municipal utility and other services to residence and businesses in Devens (id.).

the Department direct the Company to limit the rate increase to each of its customers to no more than ten percent (id.).

Further, the MDFA states that the Company's assertion that the redesign is necessary because customers find the existing G-44 rate confusing is not substantiated by the record (id. at 4). For example, according to the MDFA, the Company has not demonstrated that there is significant customer confusion about the current rates (id. at 5). The MDFA argues that there is no consistency concerning how the Company tracks complaints, which is evidenced by the low ratio of calls to customers (id., citing Exh. D.T.E. 10-19). The MDFA argues that this low complaint ratio does not support Boston Gas' contention that there is significant customer confusion or dissatisfaction with the current rate (MDFA Brief at 5, citing Exh. DTE 10-19). Second, the MDFA addresses the Company's argument that the rate should be changed due to a lack of cost-effective demand meters by indicating that the record shows that more than 15 percent of the G-44 customers already have demand meters in place, many of whom are the larger customers in this rate class (MDFA Brief at 5).

The MDFA disagrees that switching to a volumetric rate design for the G-44 class would send appropriate price signals to customers, especially considering the new rate level for the off-peak period (id. at 5-6). The MDFA contends that the Company's own witness conceded that the change to a volumetric rate skews the price signal to customers (id. at 6).

Moreover, the MDFA states that the Company's argument that the lack of development of a competitive market is a basis for eliminating the demand-based rate and switching to a

volumetric rate is flawed. The MDFA claims that moving away from the demand-based rates could further impede the development of a competitive market (id.).

Finally, the MDFA suggests that the Department should reject the proposed rate design, and that the Department should direct the Company to limit rate increases for all rate classes (id.). In addition, the MDFA argues that the Company should be directed to further study the feasibility of implementing demand meters for all G-44 ratepayers or whether the G-44 rate class should be further segregated (id. at 6-7). Therefore, the MDFA requests that the Department direct the Company to either maintain the current rate design or establish a separate demand rate for G-44 customers that have demand meters or wish to have demand meters installed (id. at7).

ii. Boston Gas

The Company argues that Rate G-44 should return to volumetric billing for the following reasons: (1) customers find the current demand billing method confusing; (2) customer cost causation is aligned thereby with customer bill impact; and (3) the rate structure would be simplified (Exh. MDFA 1-1). The Company states that the majority of G-44 customers do not have a demand meter because they cost between $1,600 and $10,300 (id.). Accordingly, for billing purposes the Company currently uses a customer's MDCQ as a proxy for a customer's maximum daily demand (id.). A customer's MDCQ is calculated using their consumption data from the peak month of the prior corresponding season, adjusted to determine a daily quantity (Exh. KEDNE/ALS-1, at 27). Boston Gas notes that the calculation of the MDCQ causes a one-year lag between a customer's consumption level and the bills that

a customer receives for that consumption (Exh. MDFA 1-1). Therefore, the Company contends that the current billing method does not provide the proper price signal because the price that a customer pays in the current year is based on their consumption in the prior year (Exh. KEDNE/ALS-1, at 27). Also, Boston Gas states that it proposes to switch to a volumetric rate because its expectations for the competitive market have not borne out and gas-metering technology has not developed in the way that it anticipated when it first established the MDCQ for billing purposes (Exhs. MDFA 2-3; MDFA 2-4).

c. Analysis and Findings

For Rate G-44, the Company first implemented a demand-based rate where demand is determined using a proxy method in D.P.U. 93-60. In D.P.U. 93-60, at 410-411, the Department directed the Company in its next rate case to (1) reevaluate, refine or replace the proxy method, (2) pursue its load research efforts, (3) study the economic feasibility of installing demand meters and designing a demand rate for the G-44 customers, and (4) review the existing rate classification and evaluate further disaggregation.

In its last rate case, D.T.E. 96-50, the Company proposed to return Rate G-44 to a volumetric billing basis, because it said customers found the demand billing method confusing (Exh. MDFA 2-1, at 17). Also, the Company proposed to create a new rate class, G-45, for those customers whose annual usage was greater than 250,000 therms (Exh. MDFA 2-1, at 19). The Company proposed to design Rate G-45 on a demand metered basis and to install demand meters for those G-45 customers that did not already have them (Exh. MDFA 2-1, at 19). Because of adverse bill impacts and the Company's withdrawal of its initial proposal,

the Department directed Boston Gas to establish a single G-44 rate, designed according to the method approved in D.P.U. 93-60. D.P.U. 96-50 (Phase I) at 163.

The cost to provide distribution service to G-44 customers is a function of the capacity reserved on the Company's distribution system to serve them, and is not a function of their volumetric throughput. Efficiency in rate structure means that it is cost-based and recovers the cost to society of the consumption of resources to produce the utility service. D.T.E. 01-56, at 135; D.T.E. 02-24/25, at 252-53. Accordingly, the appropriate billing method to satisfy the Department's efficiency goal is one based on demand.

The problem with measuring demand is that demand meters are expensive. For many rate classes, the costs of the meters outweigh the benefits of efficient pricing. As the size of a customer's load gets bigger, the cost of the meter becomes a smaller percentage of the total cost to serve that customer and, therefore, the benefits increase. For the Company's customers with the largest loads, the benefits of demand billing would outweigh the cost of installing a demand meter. However, the record is insufficient to allow us to determine the customer-size threshold above which demand billing becomes beneficial to customers.

Regarding the Company's MDCQ method of estimating demand, the record does not support the Company's contention that Rate G-44 customers find this method confusing. Also, the fact that under the MDCQ billing method there is a one-year lag between a customer's consumption level and the bills customers receive for that consumption is not of great concern, considering that the method determines a proxy for demand rather than volumetric throughput. Unlike throughput costs, demand costs typically do not change significantly from one year to

the next. Further, the Department finds that to switch back to volumetric billing would make it difficult in the future to go to demand based billing because of the high bill impacts caused from switching billing methods.

Therefore, the Department directs the Company to maintain its current billing method for the G-44 Rate in this proceeding. Further, the Department directs the Company, by its next rate case, to install demand meters for its largest customers and to design a demand rate for such customers. For those G-44 customers, if any, that do not have a demand meter at the time of the Company's next rate case, Boston Gas must provide evidence demonstrating why such customers were not converted to the demand rate.

According to the Company's MCS, the total peak season marginal cost for Rate G-44 is $0.1902 per therm (Exh. KEDNE/ALS-2, Sch. 11). According to the Company's COSS, the embedded customer charge for Rate G-44 is $688.56 per month (Exh. KEDNE/AEL-8, at 29). Accordingly, based on a review of marginal and embedded costs, and the seasonal and annual bill impacts on customers, the Department finds that a rate designed with a $510.00 monthly customer charge satisfies continuity goals and produces bill impacts that are moderate and reasonable. In addition, to price the peak delivery charge at a higher rate than the off-peak delivery charge, the Company is directed to shift revenues such that the same ratio of peak to off-peak charges in current rates maintained.

Therefore, the Department directs the Company to set the Rate G-44 charges accordingly. The Department further directs the Company to set the demand charge to collect the remaining class revenue responsibility as specified on Schedule 10.

7. Rate G-51 (C&I Low Use, High Load Factor)

The G-51 rate is available to C&I customers whose maximum hourly meter capacity is between zero and 500 cubic feet per hour and whose metered use in the most recent peak period of November through April is less than 70 percent of the metered use for the most recent twelve consecutive months of September through August (Exh. KEDNE/ALS-7 [rev.] at 13). The Company proposes to increase the monthly customer charge from $23.34 to $29.47 (Exh. KEDNE/ALS-7 [rev.] at 13). In addition, the Company designed the rates in the 50-series as single step volumetric rates rather than as "block rates" (Exh. KEDNE/ALS-1 at 28). The proposed delivery charge during the peak season is $0.2578 per therm (Exh. KEDNE/ALS-7 [rev.] at 13). The proposed delivery charge during the off-peak season is $0.2152 per therm (Exh. KEDNE/ALS-7 [rev.] at 13).

According to the Company's MCS, the total peak season marginal cost for Rate G-51 is $0.1284 per therm (Exh. KEDNE/ALS-2, Sch. 11). According to the Company's COSS, the embedded customer charge for Rate G-51 is $41.73 per month (Exh. KEDNE/AEL-8, at 29). Accordingly, based on a review of marginal and embedded costs, and the seasonal and annual bill impacts on customers, the Department finds that a rate designed with a $25.00 monthly customer charge and a single step delivery charge for the peak and off-peak seasons, satisfies continuity goals and produces bill impacts that are moderate and reasonable. In addition, to price the peak delivery charge at a higher rate than the off-peak delivery charge, the Company is directed to shift revenues such that the same ratio of peak to off-peak delivery charges proposed by the Company is maintained.

Therefore, the Department directs the Company to set the Rate G-51 charges accordingly. The Department also directs the Company to collect in the delivery charge the remaining class revenue responsibility as specified on Schedule 10.

8. Rate G-52 (C&I Medium Use, High Load Factor)

The G-52 rate is available to C&I customers whose maximum hourly meter capacity is between 501 and 1,500 cubic feet per hour and whose metered use in the most recent peak period of November through April is less than 70 percent of the metered use for the most recent twelve consecutive months of September through August (Exh. KEDNE/ALS-7 [rev.] at 14). The Company proposes to increase the monthly customer charge from $40.84 to $50.67 (Exhs. KEDNE/ALS-1, at 28; KEDNE/ALS-7 [rev.] at 14). The proposed delivery charge during the peak season is $0.2091 per therm. The proposed delivery charge during the off-peak season is $0.1221 per therm (Exhs. KEDNE/ALS-7 [rev.] at 14; KEDNE/ALS-7 [rev.] at 14).

According to the Company's MCS, the total peak season marginal cost for Rate G-52 is $0.1382 per therm (Exh. KEDNE/ALS-2, Sch. 11). According to the Company's COSS, the embedded customer charge for Rate G-52 is $70.32 per month (Exh. KEDNE/AEL-8, at 29). Accordingly, based on a review of marginal and embedded costs, and the seasonal and annual bill impacts on customers, the Department finds that a rate designed with a $45.00 monthly customer charge and a single step delivery charge for the peak and off-peak seasons, satisfies continuity goals and produces bill impacts that are moderate and reasonable. In addition, to price the peak delivery charge at a higher rate than the off-peak delivery charge, the Company

is directed to shift revenues such that the same ratio of peak to off-peak delivery charges proposed by the Company is maintained.

Therefore, the Department directs the Company to set the Rate G-52 charges accordingly. The Department also directs the Company to collect in the delivery charge the remaining class revenue responsibility as specified on Schedule 10.

9. Rate G-53 (C&I High Use, High Load Factor)

The G-53 rate is available to C&I customers whose maximum hourly meter capacity is between 1,501 and 12,000 cubic feet per hour and whose metered use in the most recent peak period of November through April is less than 70 percent of the metered use for the most recent twelve consecutive months of September through August (Exh. KEDNE/ALS-7 [rev.] at 15). The Company proposes to increase the monthly customer charge from $116.77 to $126.60 (Exhs. KEDNE/ALS-1 at 28; KEDNE/ALS-7 [rev.] at 15). The proposed delivery charge during the peak season is $0.1893 per therm. The proposed delivery charge during the off-peak season is $0.1196 per therm (Exh. KEDNE/ALS-7 [rev.] at 15)

According to the Company's MCS, the total peak season marginal cost for Rate G-53 is $0.1309 per therm (Exh. KEDNE/ALS-2, Sch. 11). According to the Company's COSS, the embedded customer charge for Rate G-53 is $146.25 per month (Exh. KEDNE/AEL-8, at 29). Accordingly, based on a review of marginal and embedded costs, and the seasonal and annual bill impacts on customers, the Department finds that a rate designed with a $127.00 monthly customer charge and a single step delivery charge for the peak and off-peak seasons, satisfies continuity goals and produces bill impacts that are moderate and reasonable. In addition, to

price the peak delivery charge at a higher rate than the off-peak delivery charge, the Company is directed to shift revenues such that the same ratio of peak to off-peak delivery charges proposed by the Company is maintained.

Therefore, the Department directs the Company to set the Rate G-53 charges accordingly. The Department also directs the Company to collect in the delivery charge the remaining class revenue responsibility as specified on Schedule 10.

10. Rate G-54 (C&I Extra-High Use, High Load Factor)

a. Introduction

The G-54 rate is available to C&I customers whose maximum hourly meter capacity is greater than 12,000 cubic feet per hour and whose metered use in the most recent peak period of November through April is less than 70 percent of the metered use for the most recent twelve consecutive months of September through August (Exh. KEDNE/ALS-7 [rev.] at 16). Currently, the G-54 class rate structure is based on a customer charge and an estimated maximum demand charge (Exh. KEDNE/ALS-1, at 28).

The Company, for the same reasons as stated for Rate G-44, proposed to return Rate G-54 to a volumetric billing basis, based on its assertion that customers find the current demand billing method confusing (Exh. KEDNE/ALS-1, at 28). In addition, the Company proposed to (1) increase the monthly customer charge from $478.31 to $587.14 (Exhs. KEDNE/ALS-1 at 28; KEDNE/ALS-7 [rev.] at 16), (2) set the delivery charge for the peak season at $0.1854 per therm, (3) set the delivery charge for the off-peak season at $0.1188 per therm for all therms consumed (Exh. KEDNE/ALS-7 [rev.] at 16).

b. Analysis and Findings

For the same reasons as stated for Rate G-44, above, the Department directs the Company to maintain its current billing method for Rate G-54 in this proceeding. Further, the Department directs the Company, by its next rate case, to install demand meters for its largest customers and design a demand rate for such customers. For those G-54 customers, if any, that do not have a demand meter at the time of the Company's next rate case, Boston Gas must provide evidence demonstrating why such customers were not converted to the demand rate.

According to the Company's MCS, the total peak season marginal cost for Rate G-54 is $0.1310 per therm (Exh. KEDNE/ALS-2, Sch. 11). According to the Company's COSS, the embedded customer charge for Rate G-54 is $804.80 per month (Exh. KEDNE/AEL-8, at 29). Accordingly, based on a review of marginal and embedded costs and the seasonal and annual bill impacts on customers, the Department finds that a rate designed with a $510.00 monthly customer charge satisfies continuity goals and produces bill impacts that are moderate and reasonable. In addition, to price the peak delivery charge at a higher rate than the off-peak delivery charge, the Company is directed to shift revenues such that the same ratio of peak to off-peak charges in current rates is maintained.

Therefore, the Department directs the Company to set the Rate G-54 charges accordingly. The Department further directs the Company to set the demand charge to collect the remaining class revenue responsibility as specified on Schedule 10.

11. The G-60 Series Rates

The G-60 Series rates are available to C&I customers whose metered use in the most recent peak period of November through April is less than or equal to 20 percent of the metered use for the most recent twelve consecutive months of September through August. The Company proposes to eliminate the G-60 series rate classes and to combine the customers and volumes associated with these classes with the similar sized G-50 series rate classes (Exh. KEDNE/ALS-1, at 29).

The Company argues that the G-60 series rate classes should be combined into the corresponding G-50 series rate classes because they have identical rate structures and, therefore, keeping them separate is unnecessary and provides no benefit to customers (id.). The Company notes that (1) the customer charge, (2) the tailblock break point, and (3) the headblock and tailblock rates for the G-50 series rate classes, are the same for the corresponding G-60 series rate classes (id.). Also, the Company notes that all of the customers currently in the G-60 series rate class are eligible for the corresponding G-50-series rate class and would be charged the same rates (id.).

Keeping the G-60 series rate classes separate from the corresponding G-50 series rate classes provides no benefits to customers and consequently is unnecessary because they have identical rate structures and eligibility clauses. Therefore, the Department approves the Company's proposal to eliminate the G-60 series rate classes and to combine the customers and volumes associated with these classes with the similar sized G-50 series rate classes.

12. Rate G-7 (Street Lighting)

Rate G-7 is available to any street lighting customer (KEDNE/ALS-7, at 16). The Company proposes a two-part rate consisting of a monthly fixed charge of $7.69 per lamp and running charges of 0.0328 cents per hour for the peak and off-peak periods (Exh. KEDNE/ALS-7, [rev.] at 17).

To determine the proposed rates, the Company first calculated the total number of lamps, with and without clocks, and computed the total running hours per season for all lamps (Exh. KEDNE/ALS-4 [rev.] at 13). Next, the Company divided the total class annual use by the total annual running hours of all lamps to derive an estimate of the therm use per lamp per hour (id.). The therm use per lamp per hour was then multiplied by the peak and off- peak marginal energy costs (taken from the Company's MCS) to arrive at the estimates for the seasonal hourly running charges (id.). Multiplying the seasonal hourly running charges by the corresponding total hours of operations, the Company arrived at the peak and off-peak energy revenues (id.). The sum of these revenues was then subtracted from the total class revenue requirements, and the difference was divided by the total number of lamps, giving the fixed annual charge per lamp (id.).

Because this service is unmetered and because the principle of simplicity in rate design is important, here in particular, the Department finds the Company's method for determining its proposed street lighting rate to be acceptable. Accordingly, the Department directs the Company in its compliance filing to set a monthly fixed charge that would recover the class's revenue requirements, as discussed above.

13. Rate G-17 (Outdoor Gas Lighting)

The G-17 rate is available to all customers for outdoor gas lighting where a standard gas light on private property cannot be metered along with the gas used for other purposes by the customer (Exh. KEDNE/ALS-7, at 17). The Company proposes a peak and off-peak monthly charge of $34.09 (Exh. KEDNE/ALS-7 [rev.] at 19). The Company determined these seasonal monthly charges by first calculating the therm-use-per- hour-per-lamp by dividing the class total annual therm use by the total annual running hours of all the lamps (Exh. KEDNE/ALS-4 [rev.] at 14). The result was multiplied by the peak and off-peak marginal energy costs (based on the Company's MCS) to derive estimates of the marginal commodity costs per hour (id.). These seasonal marginal commodity costs per hour multiplied by the running hours per lamp, provided the estimate of the monthly energy cost per lamp (id.). The Company then computed the peak and off-peak energy revenues by multiplying the estimated seasonal marginal energy cost per hour by the total peak and off-peak running hours of all the lamps (id.). The sum of the seasonal energy revenues was subtracted from the class revenue requirement, and the difference was divided by the total number of lamps, resulting in an estimate of the annual fixed charge per lamp (id.). The annual fixed charge per lamp was then added to the seasonal monthly energy cost per lamp, resulting in the proposed monthly charge (id.).

Because this service is unmetered and based upon the principle of simplicity in rate design, the Department finds the Company's method for determining its proposed rate to be acceptable. Accordingly, the Department directs the Company in its compliance filing to set a

monthly fixed charge for the peak and off-peak season that would recover the class's revenue requirements as shown in Schedule 10 and the revenue allocated to this class from Rate G-17.

G. Weather Stabilization Clause

1. Introduction

Boston Gas proposes a weather stabilization clause ("WSC") tariff designed to minimize fluctuations in customer bills due to weather variability (Exhs. KEDNE/ALS-1, at 31; KEDNE/ALS-6; RR-DTE-3 [rev.]; Tr. 4, at 407).[162] The proposed WSC applies to all rate classes, except rates G-7 (street lighting) and G-17 (outdoor gas lighting). Under the proposed WSC, each customer's bill will be adjusted in each billing cycle[163] during the peak period (November through April) to account for any variation in weather that deviates by more than two percent from normal weather (Exh. KEDNE/ALS-1, at 32).[164]

In determining the WSC adjustment, the Company will first calculate the actual and normal degree days during that billing cycle and then determine the percentage difference between actual and normal degree days (Exh. KEDNE/ALS-1, at 33; RR-DTE-89). If the

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162 The Company initially referred to its proposal as a "weather normalization clause." However, Boston Gas later agreed that its proposal is more properly identified as a "weather stabilization clause"(RR-DTE-3 [rev.]; Tr. 4, at 407).

163 The WSC adjustment will be separate from the proration of customers' bills that took effect July 1, 2002 as a result of the conversion to the CRIS (Tr. 4, at 422).

164 Boston Gas' proposed WSC tariff describes the components and specifies the formula for the WSC adjustment (Exh. KEDNE/ALS-6; RR-DTE-3 [rev.]). That formula includes the use of an average degree day factor and a base load factor applicable for each rate class (id.). The Company also provided a sample bill for its proposed WSC (RR-DTE-9; Tr. 4, at 420-421).

difference is less than plus or minus two percent, no WSC adjustment will be made (id.). If the difference is greater than plus or minus two percent, the Company will calculate the WSC adjustment by first subtracting two percent from that difference to determine the class-specific WSC adjustment percentage for that billing cycle (id.). Using the base load factor and heating load factor associated with the customer's rate class, the Company will determine the portion of the customer's use that is temperature-sensitive (id.). Next, the Company multiplies the class-specific WSC adjustment percentage by the portion of the customer's total use that is temperature-sensitive to determine the customer-specific WSC adjustment percentage (id.). This customer-specific WSC adjustment percentage is then multiplied by the tailblock rate for the customer's rate class to determine the WSC adjustment factor for that customer (id.). Finally, the WSC adjustment factor is multiplied by the total therms billed to the customer for that billing cycle to produce the customer's WSC bill adjustment (id.).[165]

The Company states that the two percent deadband allows for a reasonable level of variability in customers' bills when the weather is relatively close to normal, while smoothing the extreme variability in customers' bills that results when the weather deviates more significantly from normal levels (Exh. KEDNE/ALS-1, at 34). Boston Gas proposed to use

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[165] The Company provided a detailed explanation of how customers' bills would be adjusted under the proposed WSC tariff (Exhs. AG 8-5; DTE 3-27 [rev.]; DTE 3-29; DTE 10-20; DTE 10-21). In addition, the Company provided a pro forma copy of its update to be filed with the Department annually (Exhs. KEDNE/ALS-1, at 34; DTE 3-23; RR-DTE-4; RR-DTE-89). This annual filing will include (1) the average base load factor, average degree day factor, and tailblock rates for each rate class, (2) monthly normal degree days, and (3) a description of the steps used to calculate the WSC adjustment (id.).

the most recent 20-year average daily degree days from 1983 through 2002 in the Company's service territory to define normal weather (id. at 32-33; RR-DTE-3 [rev.]; Tr. 24, at 3256).[166]

The Company acknowledges that, except for the amount of the percentage deadband, the formula in its proposed WSC tariff is identical to the formula for weather normalization adjustment that is currently in effect for Keyspan Gas East Corp. d/b/a Brooklyn Union of Long Island ("Keyspan Gas East") in New York (Exh. AG 8-3(j); Tr. 21, at 2877-2878). Keyspan Gas East has a 2.2 percent deadband determined to be equal to one-half the standard deviation from normal weather (Exh. AG 8-4(d) at 21; Tr. 21, at 2882-2883). Boston Gas did not perform any statistical study as a basis for determining its proposed two percent deadband because its WSC "proposal is designed to parallel the mechanism in place in New York" (Exhs. DTE-3-21; AG-8-3(j); Tr. 21, at 2878).

Boston Gas also indicates that the formula for the weather normalization adjustment currently in effect for Keyspan Gas East is virtually identical to the formula used by Keyspan Gas West (also called BUG). The only difference is that the weather adjustment for Keyspan Gas East is based on variations in degree days while the weather adjustment for BUG is based on variations on revenues (Exh. AG 8-3(k) at 3; Tr. 21, at 2877; Tr. 22, at 2925).[167] More

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166 The Company later stated that it would use a 20-year rolling average of daily degree days in its annual WSC filing (RR-DTE-3 [rev.]; Tr. 24, at 3256). The Company also stated it would modify its definition of normal weather in its annual PBR compliance filing to use a 20-year rolling average (RR-DTE-8).

167 Keyspan has two gas affiliates in New York as a result of a 1998 Long Island transaction, each with its own set of rates – Keyspan Gas East operates in Long Island, which was part of the "old" BUG; and Keyspan Gas West, which is still also referred

(continued…)

specifically, instead of the 2.2 percent deadband, BUG uses a 12.8/87.2 percent ratepayers/shareholders sharing of the difference between actual revenues and revenues that would be produced under normal weather conditions (Exh. AG 8-3(k) at 3; Tr. 22, at 2925). Boston Gas adds that the 2.2 percent deadband for Keyspan Gas East and the 12.8 percent margin sharing with ratepayers for BUG accomplish the same purpose as the weather normalization adjustment for revenues but use different variables (Tr. 22, at 2925).

Boston Gas states that when actual weather varies from normal, the Company's actual firm sales volume will differ from the billing determinants used to design distribution rates (Exh. KEDNE/ALS-1, at 31). Colder than normal weather will result in greater gas use, higher customer bills and higher Company revenues, while warmer than normal weather will result in lower gas use, smaller customer bills and lower Company revenues (id. at 31-32). In turn, this causes Boston Gas to generate a greater or lesser amount of revenue if the weather is colder or warmer than normal (id. at 31). These fluctuations in customer bills and Company revenues due to weather changes are exacerbated by Boston Gas' rate design method, which assigns 65 percent of the annual non-gas costs to the peak period based on embedded cost allocation and recovers 18 percent of costs from the tailblock rate based on marginal costs (Exhs. KEDNE/ALS-1, at 32; DTE 3-22).

Boston Gas states that the WSC proposal is not intended to stabilize its distribution revenues (Exh. KEDNE/JFB-1, at 45). Boston Gas has not entered into a weather hedging

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[167] (…continued)
to as BUG (Tr. 21, at 2876-2879).

arrangement for the 2003-2004 heating season (Exh. DTE 3-18; Tr. 21, at 2885; Tr. 22, at 2909). The Company states that with an approved WSC, it will no longer need an arrangement with a financial partner to stabilize revenues due to weather variability (Tr. 22, at 2956).[168]

2. Positions of the Parties

a. Attorney General

The Attorney General argues that Boston Gas' proposed WSC should be rejected, contending that the Company's proposed WSC suffers the same defects as past WSC proposals rejected by the Department (Attorney General Brief at 93-94, citing D.P.U. 92-111, at 57-61; D.P.U. 92-210, at 191-199).[169]

The Attorney General claims that the WSC proposal will significantly reduce the Company's weather-related risks and shift them to ratepayers (Attorney General Brief at 95). The Attorney General claims that the Department has stated that any reduction in shareholders'

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[168] Boston Gas explains that its proposed WSC is the same as the weather hedging arrangement it currently enters into with an outside financial partner (Tr. 22, at 2906). That is, if the weather turns out to be warmer than normal the financial partner pays the Company, and in the case of the proposed WSC, ratepayers pay the Company (id.). If the weather turns out to be colder than normal, the Company pays the financial partner, and in the case of the proposed WSC, the Company pays the ratepayers (id.).

[169] The Attorney General notes that the Company's WSC proposal is addition to its weather normalization adjustment (Attorney General Brief at 93). The Attorney General contends that Boston Gas' weather normalization adjustment is designed to normalize the Company's test year sales volumes to a level that would have occurred had the test year been a normal weather year (id.). The Attorney General claims that this existing weather normalization adjustment allows for a neutral allocation between ratepayers and shareholders of the risk that the upcoming year will be colder or warmer than normal (id. at 93, citing D.P.U. 92-111, at 41).

risks should be commensurately shared with ratepayers through a reduction in ROE (id. at 95, citing D.P.U. 92-111, at 60-61). The Attorney General asserts that because the Company did not propose any adjustment to ROE to incorporate this reduction in risk, the Department should reject the proposed WSC (Attorney General Brief at 95).

The Attorney General asserts that the proposed WSC will stabilize Boston Gas' revenues (id. at 94). He adds that the Company would no longer need to enter into weather hedging financial arrangements in order to remove the risk of weather volatility and, thus, avoid this expense and transfer the risk of weather volatility to its customers (Attorney General Reply Brief at 49, citing Tr. 21, at 2884-2885). The Attorney General claims that the Company could receive a $14.5 million benefit, aggregated from the small changes in customers' bills, an amount much more than the customer benefit that Boston Gas asserts (Attorney General Reply Brief at 49-50, citing RR-DTE-5).[170]

The Attorney General disputes the Company's claim that there is no need to adjust the ROE because companies in the barometer group that were used as a basis for determining its proposed rate of return have weather adjustments (Attorney General Reply Brief at 51). The Attorney General argues that, because the Department has never set an ROE on a company that has a WSC, reducing Boston Gas' risk of revenue volatility due to weather could significantly

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[170] The Attorney General calculated the $14.5 million amount by (1) assuming an average customer in each rate class, (2) calculating the WSA adjustments for the peak months of that customer based on record request DTE-5, (3) multiplying the result by the total number of bills in that rate class, and (4) aggregating the results for all rate classes (Attorney General Reply Brief at 50, n.40).

reduce its cost of capital to a level below that of companies that do not have a weather stabilization adjustment (id. at 51).

The Attorney General claims that the Company's WSC proposal is anti-competitive because it will raise prices in warmer weather, thus sending distorted price signals (Attorney General Brief at 96). The Attorney General suggests that if the Company's goal is to protect ratepayers from volatility in their bills, the Department should take the opportunity to consider the propriety of WSCs for all Massachusetts customers in a generic investigation that considers the outlook for retail residential competition (id. at 95-96).

The Attorney General claims that when evaluating past WSC proposals, the Department has expressed concern with the reliability and accuracy of weather data (Attorney General Reply Brief at 50; Attorney General Brief at 94-95, citing D.P.U. 92-111, at 57-61; D.P.U. 92-210, at 191-199 (1993)). The Attorney General claims that the Company's WSC proposal does not have reliable weather data because it uses the normal degree day information from only one location, Logan International Airport ("LIA") (Attorney General Brief at 96). The Attorney General argues that the WSC proposal calculates the heating factor increment at a rate class level, which ignores customers who experience weather different from that recorded at the LIA weather station (id.). Therefore, the Attorney General argues that the Company will not be able to accurately implement the WSC adjustment on those customers' bills (id.).

The Attorney General notes that the Company has adopted a new method for calculating daily degree days as a result of the conversion to the CRIS (Attorney General Reply Brief at

51). The Attorney General claims that the monthly normal and actual billed degree day calculations are different and that the Company has not shown that the new method will not distort the WSC calculations (id.). The Attorney general further contends that the Department would have difficulty discovering this distortion in any type of audit (Attorney General Reply Brief at 51, citing and comparing RR-DTE-19, RR-DTE-19 [rev.]). The Attorney General also asserts that the proposed WSC would result in rates that are not just or reasonable because it applies to both heating and non-heating customers (Attorney General Brief at 96-97). The Attorney General claims that the Department has previously expressed concerns about possible unfair intra-class subsidization if non-heat sensitive customers are included in a WSC (id. at 97, citing D.P.U. 92-111, at 58). The Attorney General states that such intra-class subsidization could result in customer confusion and dissatisfaction, contradicting the Department's rate design goal of simplicity (Attorney General Brief at 97).

The Attorney General adds that unjust and unreasonable rates will also result from the calculation of the WSC adjustment, which is based on the tailblock rate of each rate class (id.). The Attorney General reasons that because all rate classes' tailblock rates are not at marginal cost, one rate class is likely to be subjected to a higher weather adjustment than another rate class (id.). The Attorney General claims that the Company's WSC proposal is poorly designed and that any potential ratepayer benefit is far outweighed by its inherent problems (id. at 98).

b. Boston Gas

The Company argues that its WSC is well designed and raises none of the concerns that have been raised with previous WSC proposals presented before the Department (Boston Gas

Brief at 209). Boston Gas maintains that the only benefit to the Company under its proposed WSC is increased customer satisfaction (id. at 205).

The Company argues that its proposal is not designed to stabilize its revenues (id.). The Company contends that it has other mechanisms in place to accomplish this objective, such as entering into financial arrangements that hedge the risk of weather volatility (id.).[171] Rather, Boston Gas argues that the volatility in gas prices experienced in the past three years and the cold weather of the past winter has had a significant effect on customers and that the Company is under increasing pressure to mitigate the impacts of these factors for customers (Exh. KEDNE/JFB-2, at 46; Tr. 22, at 2943-2944).

Boston Gas adds, however, that under its WSC proposal, the Company would be able to mitigate the impacts of weather variability on customer bills while at the same time stabilize its distribution revenues (Tr. 22, at 2914).[172] The Company claims that customers generally do not have that same ability to hedge weather risk and, therefore, a WSC would provide ratepayers the same benefit the Company obtains in the marketplace (Boston Gas Brief at 205,

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[171] Boston Gas argues that "[through the implementation of a WSC], the Company would be able to provide benefits to its customers, rather than enriching third-party financial institutions through hedging activities"(Exh. KEDNE/PRM-1, at 13). During the 2002-2003 heating season, Boston Gas paid a total of $14,590,000 under its weather-hedging contracts to its financial partner (Exhs. KEDNE/JFB-1, at 46; AG 8-41; DTE 3-17; Tr. 22, at 2904). Had a WSC been in place during the 2002-2003 heating season, the Company argues that these funds would have been paid instead to Boston Gas' ratepayers (Tr. 22, at 2951-2952). Boston Gas received $1.49 million from its financial partner under this hedging arrangement for the period from November 2001 to December 2001 (Exh. DTE 3-19; Tr. 22, at 2905).

[172] The Company notes that "[v]ariations in weather affect customers' bills and the Company's cash flow" (Exh. KEDNE/PRM-1, at 13).

209; Boston Gas Reply Brief at 46). The Company claims that a WSC "would efficiently match the complementary weather risks of the Company and its customers, concerning the distribution portion of the customer bill, enabling both to benefit from the moderation of price volatility that the Company alone currently enjoys" (id. at 209).

The Company states that the Department's WSC precedent relied upon by the Attorney General is more than a decade old and, at that time, financial arrangements to avoid the risk of weather volatility were not available (Boston Gas Brief at 205, citing Attorney General Brief at 94; D.P.U. 92-111; D.P.U. 92-210). The Company argues that because its WSC is designed only for the benefit of its customers, the Department's concern about the allocation of benefits is no longer an issue (Boston Gas Brief at 205, citing D.P.U. 92-111 and D.P.U. 92-210).

The Company claims that the proposed WSC does not require an adjustment to the Department's allowed ROE because the WSC benefits customers (Boston Gas Brief at 206). In addition, Boston Gas also claims that the companies it included in its ROE Comparison Group either have WSCs or are expected by investors to take advantage of the same type of hedging financial instruments used by the Company to remove the risk of weather volatility (Boston Gas Brief at 206, citing Tr. 15, at 1937-38).

The Company asserts that the Attorney General incorrectly interprets the Department's rationale for rejecting previous WSC proposals because such proposals represent a movement back to cost-based regulation and away from market-based regulation (Boston Gas Brief at

206, citing Attorney General Brief at 95). The Company argues that its WSC proposal raises no obstacle to the movement from cost-based regulation to market-based regulation because its WSC proposal is solely on the distribution charge, not the commodity charge (id. at 206-207).

Regarding the reliability of its weather data, the Company claims that the Attorney General fails to recognize that the WSC is not intended to measure the absolute differences in weather degree days experienced by each individual customer, but instead is designed to measure the deviation of actual weather from a defined normal to determine the percentage adjustment for all customers throughout the service territory (id. at 207). Boston Gas argues that the absolute differences in the weather degree days experienced by customers are irrelevant (id.). Rather, the Company argues that the important consideration is a high degree of correlation in the deviations from normal weather (id.). The Company adds that, once that high degree of correlation is established, it is appropriate to infer that a certain deviation from normal weather in one location will accurately include the percentage changes from normal weather experienced by all customers, regardless of location within the service territory (id. at 207-208). The Company argues that it proposed to use LIA weather station data because LIA is geographically centered and, as such, there is a high degree of correlation between heating degree days for LIA and those in other areas of its service territory (id. at 208, citing Exh. AG 19-31). The Company adds that the use of LIA weather data in this manner is consistent with the Department's Order in its most recent long-range resource and requirement plan (id. at 208, citing Keyspan Energy Delivery New England, D.T.E. 01-105, at 5 (2003)).

Regarding the Attorney General's criticism that a WSC for non-weather-sensitive customers would create confusion, the Company claims that it has provided evidence that sendout for each rate class included in the WSC is temperature-sensitive (id. at 208, citing Exhs. DTE 2-42; DTE 2-44). The Company asserts that, because customers within non-weather sensitive rate classes are already subject to fluctuations in billing amounts based on changes in weather, it is appropriate to apply the WSC to each of the rate classes included in the WSC (id. at 208). Finally, addressing the Attorney General's argument that applying the WSC adjustment to the tailblock portion of rates will result in unjust and unreasonable rates, the Company argues that the tailblock portion of the rate is the appropriate rate component use because the weather-sensitive portion of the customer's bill is billed at the tailblock rate (id. at 209).

3. Analysis and Findings

The Department has previously considered similar weather stabilization proposals. In D.P.U. 92-111, at 60-61, the Department rejected Bay State's proposal because (1) other alternative approaches to improving earnings stability were not considered, (2) the proposal represented a movement towards cost-based regulation and away from market-based regulation, (3) questions existed about whether the resulting rates would be just and reasonable, (4) verifiable procedures were absent for reviewing weather data used in the calculations, and (5) concerns existed about the allocation of benefits and risks. The Department concluded that "any reduction in risk on equity investments in Bay Sate should be

shared commensurately with Bay State's ratepayers through the reduction in the rate of return on equity." Id.

In D.P.U. 92-210, 199-200, the Department rejected Berkshire's weather stabilization proposal, stating that it was not in the ratepayers' interest, and noted that Berkshire had not adequately responded to the concerns raised by the Department in D.P.U. 92-111. The Department found:

> as minimum requirements for the Department to consider a review of any future [weather stabilization adjustment] proposal, such a proposal must: first, provide a commensurate adjustment in a company's proposed rate of return on capital; and second, respond to the changes in the natural gas industry and the increasing application of competitive market forces in the allocation of energy resources.

Id.

The Company's proposed WSC is designed to parallel the weather normalization adjustment mechanism currently in use by Keyspan's gas utility affiliate operating in New York, Keyspan Gas East. Therefore, in evaluating the Company's WSC proposal, we briefly describe below how the New York WSC was established.

The New York WSC was established in November 1980 for the "old" BUG. At that time, BUG's weather normalization adjustment at that time was designed to adjust customers' bills for all deviations from normal weather (Exh. AG 8-49(d); RR-DTE-81; Tr. 21, at 2881, 2883). This mechanism was consistent with a New York statute that provides the New York Public Service Commission ("NYPSC") with "the power to provide for the refund of any revenues received by any gas or electric corporation which caused the corporation to

have revenues in the aggregate in excess of its authorized rate of return for a period of [twelve] months" (Tr. 21, at 2890-2891).[173]

In a 1990 proceeding before the NYPSC,[174] BUG opposed the introduction of a deadband, claiming that its existing clause protected both customers and the company from large revenue swings and was built into investors' assessments of the risks involved with an investment in the company's debt or equity securities (Exh. AG 8-4(d) at 22; Tr. at 21, at 2883). BUG added that changes in the weather clause, such as the application of a deadband, introduce earnings variability and will likely result in a higher cost of capital (Exhs. AG 8-4(d) at 22; AG 8-4(e) at 62; Tr. 21, at 2883).[175] The NYPSC directed BUG to either (1) adopt a weather normalization clause similar to that approved for National Fuel Gas Distribution Corporation ("National Fuel") which had a one-half standard deviation deadband equal to 2.2 percent, or (2) show cause why its clause should not be modified to be consistent with that of National Fuel (Exhs. AG 8-3(b), at 7; AG 8-4 (d) at 21-22; Tr. 21, at 2882-2883).

The Department's current ratemaking treatment of the effects of weather changes on distribution revenues allows gas utility companies to adjust actual test year billing units and revenues to the levels that would have occurred had the weather been normal, defined to be the

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173 N.Y. Pub. Serv. Law § 66(20), Art. 4.

174 P.S.C. Case No. 90-22 (Exh. AG 8-3(e) at 19; Tr. 21, at 2880).

175 In Opinion and Order Approving Settlement with Modifications, Opinion No. 94-22 dated October 18, 1994, the NYPSC approved a stipulation by the parties to the settlement that Brooklyn Union Gas Company "shall implement a WNC 'deadband' of 2.2 [percent]" (Exh. AG 8-3(e) at 19; Tr. 21, at 2880).

average daily degree days for 20 years. D.T.E. 02-24/25, at 73-75; D.P.U. 96-50 (Phase I) at 36-39; D.P.U. 93-60, at 75-80; D.P.U. 92-210, at 194. Distribution rates are calculated based on the test year weather normalized billing units and the approved revenue requirement, which includes the company's allowed return on its investments. Therefore, Massachusetts gas utility companies bear the risks of distribution revenue fluctuations due to weather variations from normal between rate cases. If the weather post-test year turns out to be colder than normal for a given year, a gas utility company is allowed to keep all the revenues in excess of what the revenues would have been had the weather been normal. Similarly, if the weather turns out to be warmer than normal, the gas utility company bears the shortfall in revenues from what the revenues would have been had the weather been normal. Although earnings stability is one of our rate structure goals, our ratemaking precedent on test year weather normalization adjustments, noted above, allows for deviations of distribution revenues from test year levels.

The Company calculated the normal weather and the corresponding estimates of standard deviations for the peak months of November through April and then determined how many standard deviations would the proposed two percent deadband for each peak month represent (RR-DTE-6; RR-DTE-90). The two percent deadband in the Company's WSC proposal would be equivalent to numbers ranging from 0.2 to 0.5 standard deviations from normal weather (id.).[176] Boston Gas proposed standard deviation deadbands, therefore, are

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[176] The proposed two percent deadband is equivalent to 0.2, 0.2, 0.3., 0.5, 0.3 and 0.2 standard deviation for the months of January, February, March, April, November, and (continued…)

smaller compared to that in New York for all the peak months except for April, where they are equal. A smaller standard deviation deadband means that a correspondingly larger portion of revenue fluctuations due to weather deviations from normal would be stabilized.[177] Therefore, although the Company claims that its proposal is designed to parallel the Keyspan mechanism in New York, the end result is far from similar.

There is a statistically significant relationship between customers' gas use and the changes in heating degree days (RR-DTE-21; Tr. 24, at 3275-3276). As stated above, Department's ratemaking precedent requires a gas utility company to adjust its actual test year billing units and revenues to conform to normal weather. In addition, a gas utility company must calculate distribution rates that recover its approved revenue requirement, using such normalized test year billing units. The approved revenue requirement includes a component that provides the Company the opportunity to recover its allowed return on capital. Therefore, variations in revenues because of variations in weather from normal would be translated into

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176 (…continued)
December, respectively (RR-DTE-90).

177 Plus and minus 0.2, 0.3, and 0.5 standard deviation applied on the mean of a normal distribution are equivalent to 16 percent, 24 percent, and 38 percent, respectively, of the area under the normal distribution function. See Kleinbaum, David G., Lawrence L. Kupper, Keith E. Muller, and Azhar Nizam, Applied Regression Analysis and Other Multivariable Methods, 3rd Edition, Duxbury Press, 1998, at 712-713. Plus and minus one half standard deviation, equivalent to 2.22 percent in the case of New York WSC, applied on the mean of a normal distribution, means that 62 percent of revenue fluctuations due to weather deviations from normal would be stabilized. In the case of Boston Gas' WSC proposal, plus and minus two percent is equivalent to 0.2 standard deviation for the months of December, January, and February. This means that for those three coldest months, 84 percent of revenue fluctuations due to weather deviations from normal would be stabilized.

variations in the amount of distribution revenues recovered that are attributable to the component of total revenue requirement intended for the recovery of the Company's return on its investments.

If approved, the Company's WSC will remove at least 62 percent, but possibly up to 84 percent, of the variations in Boston Gas' total revenues. Therefore, under the Company's WSC proposal, Boston Gas' revenues would be more stable. This outcome is inconsistent with existing Department precedent (described above), whereby gas utility companies bear the risk of revenue fluctuations due to deviations from normal weather after rates have been set based on a given test year.

Accordingly, based on the analysis above, the Department finds that the Company's proposed WSC would result in a reduction of the Company's risk.[178] The Department reaffirms its finding in D.P.U. 92-210 that a threshold requirement for Department review of any weather stabilization adjustment proposal is that it must provide a commensurate adjustment in a company's proposed rate of return on capital. The record in this proceeding shows that the Company has not proposed such a commensurate adjustment (Exh. KEDNE/PRM-1, at 12).

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[178] The case of BUG is the converse. Prior to the application of the 2.2 percent deadband, BUG adjusted bills and revenues for all weather deviations from normal. Therefore, prior to the use of the deadband, Brooklyn Union bore zero percent of the risks of revenue variations from normal. It would only be logical for BUG to argue that including the 2.2 percent deadband, which eliminated the weather normalization adjustment within one-half standard deviation, would introduce a corresponding earnings variability and result in a higher cost of capital (Exhs. AG 8-4(d) at 22; AG 8-4(e) at 62; Tr. at 21, at 2883).

Although the Company argued that its proposal is not intended to stabilize distribution revenues but rather customer bills, the record shows that the proposed WSC would stabilize both customers' bills and, happenstantially, Company revenues (Tr. 22, at 2914). In addition, the Company acknowledged that if the Department approved its proposed WSC, it would not enter into a similar weather hedging mechanism initiated in November 2001 and used during the 2002-2003 heating season. The Company would not have the need to purchase weather insurance to mitigate the volatility in distribution revenues and avoid the costs of the associated premiums or fees.

The proposed WSC is designed to stabilize customers' distribution bills to within two percent of normal weather. This mechanism would tend to reduce, if not eliminate, the role of efficient pricing in the recovery of distribution service costs. More specifically, if the weather is colder than normal, customers may not factor the price of distribution service in their consumption decisions, anticipating that their actual monthly bills will not go beyond two percent of their normal weather bills. On the other hand, if the weather is warmer than normal, customers also may not factor the price of distribution service in their consumption decisions, knowing that their actual monthly bills would be increased even if their actual needs would be less that their normal weather consumption. Thus, the proposed WSC would not be consistent with the Department's rate structure goal of efficiency because it does not provide the correct price signal to encourage efficient use of distribution services.

Because of the change from its previous billing system to CRIS, the actual daily heating degree days to be used for the purpose of the WSC adjustment will be based on the average

temperature over nine three-hour intervals, subtracting that average from 65 degrees Fahrenheit (RR-DTE-19 [rev.]; RR-DTE-20; Tr. 24, at 3266-3267). Although the Company indicated that the average temperature is included in the Company's daily weather data supplied by its weather service provider, the Company has not presented a verifiable procedure for reviewing weather data. In turn, want of a verifiable procedure would render virtually impossible the verification of the monthly WSC adjustments on customers bills from tariffed rates. The Department finds that both the inability to provide the proper price signal, and the difficulty in verifying billing cycle weather data with the corresponding WSC adjustments would result in customer confusion, thereby violating the Department's rate design goal of rate simplicity.

For the reasons discussed above, the Department finds that the Company failed to address the concerns expressed in D.P.U. 92-111 and D.P.U. 92-210. Accordingly, the Department denies the Company's proposal for a weather stabilization clause.

VII. CGA AND LDA CLAUSES

A. Gas Industry Research and Development

1. Introduction

Boston Gas proposes to establish a mandatory surcharge to support gas research and development ("R&D") efforts.[179] The surcharge is intended to replace a Federal Energy

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[179] Because of his membership on the NARUC public interest advisory committee of the Gas Technology Institute, one of the entities that has traditionally received R&D funding from Boston Gas, Commissioner W. Robert Keating has recused himself from consideration of this proposal in order to avoid the appearance of a conflict of interest.

Regulatory Commission ("FERC") approved interstate pipeline surcharge to LDCs, typically passed on to customers, that has been supporting gas industry R&D (Exhs. KEDNE/JFB-1, at 53; KEDNE/RBE-1, at 9; Tr. 9, at 1037). Pursuant to a 1998 agreement between the FERC, the interstate pipelines, and the LDC industry, the pipeline surcharge will be phased out before the end of 2004 (Exh. KEDNE/JFB-1, at 53; Tr. 9, at 1041).[180]

Boston Gas proposes to collect a surcharge of 1.74 cents per 1,000 cubic feet ("Mcf") on pipeline gas only, and to recover this charge through the LDAC (Exh. KEDNE/JFB-1, at 54).[181] The Company estimates that, based on test year weather-normalized load, the annual R&D revenues collected by the proposed surcharge would be approximately $1.4 million (id.). Boston Gas states that it will use its New York affiliates' currently existing R&D unit to supervise the funding and support of various R&D efforts (id.). Although the Company does not seek approval for the funding of specific R&D efforts in the instant filing, it states that it will submit such a proposal for Department review by December 1, 2003, if the surcharge is approved (id. at 55).

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[180] In 1998, FERC, the interstate pipelines, and the LDC industry agreed to phase out the surcharge as a result of gas industry restructuring (Exhs. KEDNE/JFB-1, at 53; KEDNE/RBE-1, at 9). According to the Company, pipeline-to-pipeline competition and discounting of large customers led to concerns that a pipeline carrying the surcharge would be at a competitive disadvantage relative to pipelines that did not carry the surcharge (Exh. KEDNE/RBE-1, at 9). Elimination of the FERC-approved funding mechanism leaves it to state public utility commissions to adopt, at their discretion, a surcharge to maintain R&D funding (id.).

[181] The surcharge was 1.74 cents per Mcf in 1998, the year that the FERC and the gas industry agreed to phase it out by gradually decreasing it (Exh. KEDNE/JFB-1, at 53).

2. Positions of the Parties

a. Attorney General

The Attorney General argues that the Department should reject the Company's proposed R&D surcharge because it is unnecessary, unfair, and premature (Attorney General Brief at 61). Specifically, the Attorney General asserts that the Company's proposal is: (1) unnecessary, because R&D proposals will proceed whether or not they are partially funded by Boston Gas' customers; (2) unfair, because the proposed charge would force all Boston Gas distribution customers to subsidize R&D that would primarily benefit other competitive businesses that do not pay a charge; and (3) premature, because the FERC charge is not yet phased out, and a new charge would lead to double collection in the rate year (id. at 62).

The Attorney General argues that there is no persuasive evidence that Boston Gas' customers will receive direct benefits from the proposed R&D surcharge (id.). Instead, the Attorney General asserts that a large number of other entities will benefit from the effects of the proposed R&D surcharge without contributing to it (e.g., exploration and production companies, pipeline companies, appliance sellers, and the transportation companies, as well as Keyspan's various unregulated subsidiaries) (id. at 63). Because Keyspan's shareholders will benefit from any R&D that leads to the lower cost of gas, greater consumption, and greater revenues for the Company, the Attorney General argues that shareholders should fund R&D projects (id.). The Attorney General notes that Keyspan, as a whole, did not make any voluntary R&D contributions during the test year (id., citing RR-AG-40).

b. AIM

AIM asserts that approval of Boston Gas' R&D surcharge proposal is not appropriate at this time (AIM Reply Brief at 2). Although AIM recognizes the value and importance of R&D in the natural gas industry, it argues that R&D benefits should be realized state-wide for all gas and electricity consumers (id.). Therefore, AIM supports a state-wide comprehensive plan for gas and electric R&D, funded by a generic distribution charge (id.). Finally, because the Company does not offer a formal plan for spending the R&D funds to be collected, AIM recommends that the Department not approve the Company's proposed surcharge (id.).

c. Boston Gas

Boston Gas asserts that R&D efforts benefit the utility and, consequently, the customers (Tr. 21, at 2868). The Company did not address the issue of R&D funding in its initial or reply brief.

3. Analysis and Findings

There are several inadequacies in the Company's proposal that weigh against the approval of the proposed R&D surcharge. First, the Company claims that the proposed surcharge benefits the consumers asked to carry the financial burden for the research, but does not offer proof of this claim. However, these consumers, if they in fact do benefit, are not the only beneficiaries.[182] Gas utilities such as Boston Gas, natural gas producers, interstate pipelines, manufacturers, and retailers will also benefit from this research; yet, under the

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[182] The Company itself states that R&D efforts provide a shared benefit to utilities and natural gas consumers (Tr. 21, at 2868).

Company's proposal, only natural gas consumers provide the funding. In addition, because the Company is the only LDC to propose a surcharge to date, Boston Gas' customers would be paying for R&D programs providing asserted benefits not just for themselves but for other utility customers in Massachusetts and, perhaps, nationwide. Thus, the costs to Boston Gas' customers would be asymmetrical to the purported benefits these customers may receive. Further, the current FERC-approved surcharge will be phased out before the end of 2004. Therefore, initiation of the Company's proposed new surcharge before the FERC-approved surcharge ends would result in double collection from customers.

Moreover, the Company has not yet presented the Department with its plan for spending the R&D funds to be collected. It could have done so as part of its proof, but chose not to. The Department is reluctant to approve the collection and disbursement of R&D funds prior to review of a detailed proposal outlining specific research projects and the associated costs and benefits to the particular customers who are paying the surcharge. Without such a review, there is no way for the Department to determine whether and how specific R&D programs would benefit Boston Gas' customers. Moreover, we are unwilling to incorporate such a charge into rates for monopoly distribution customers without a much more persuasive case than the Company has seen fit to mount. Oil dealers, for example, cannot force their customers to shoulder such costs on the claim of some undescribed and unproven benefit; nor should gas customers be forced to do so on such an unconvincing record.

Finally, the role of R&D efforts in the Massachusetts natural gas industry is a matter of concern to numerous affected parties. The merits of R&D funding and a mechanism for

recovery should be considered in a broader investigation involving all Massachusetts LDCs. Therefore, because the Company has failed to present a detailed proposal for review, because collection of a new surcharge would be premature, and because the present case does not provide an appropriate context for review of a R&D surcharge, the Department does not approve the Company's proposed R&D surcharge.

B. Non-Firm Margins

1. Introduction

Boston Gas proposes to adjust the current mechanism, established in Interruptible Transportation Capacity Release, D.P.U. 93-141-A (1996), for calculating and sharing of the margins associated with interruptible transportation, interruptible sales, capacity release and off-system sales (Exh. KEDNE/JFB-1, at 48).[183] Specifically, the Company proposes to: (1) eliminate the separate categories of transactions; (2) eliminate the threshold structure of the margin-sharing framework; and (3) apply the 25/75 percent margin-sharing formula to total non-firm margins (id. at 52).

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[183] In D.P.U. 93-141-A, at 63, 64, the Department established several categories of transactions that are eligible for the sharing of margins. In each of the categories, the Department allowed jurisdictional LDCs to retain 25 percent of all revenues earned in a given twelve-month period above a threshold level, defined as the revenues earned in the category during the prior twelve-month period. The remaining 75 percent of revenues are flowed back to firm customers (Exh. KEDNE/JFB-1, at 48).

2. Positions of the Parties

a. Attorney General

The Attorney General states that there have been changes in the natural gas industry and in Massachusetts that could possibly support a change in the Department's policy with respect to the sharing of margins associated with interruptible transportation, interruptible sales, capacity release, and off-system sales (Attorney General Brief at 102-104). However, the Attorney General argues that these changes affect most of the LDCs in the state and are, therefore, better addressed in a generic proceeding in which all interested parties may be heard (id. at 104). The Attorney General, therefore, recommends that the Department open a generic investigation into the need for margin sharing, the changes that affect the categories of costs currently subject to margin sharing, and the development of a revised policy to provide appropriate cost mitigation and incentives (id.).

b. MOC

The MOC did not address the Company's proposal to adjust the current margin sharing mechanism but argues, instead, that the Department should require the Company's new and existing interruptible customers to have sufficient backup supplies of alternative fuel for periods of interruption (MOC Brief at 38). The MOC requests that the Department require that Boston Gas' interruptible customers have minimum backup fuel for a period that the Department determines to be sufficient (id. at 42). In addition, the MOC proposes that new customers applying for interruptible service from the Company be required to have actual

on-site storage and inventories prior to the commencement of the heating season, in an amount to be determined by the Department (id.).

c. Boston Gas

In support of its proposal to adjust the margin sharing mechanism, Boston Gas states that at the time the Department established its margin sharing policy in D.P.U. 93-141-A, the natural gas marketplace was in the initial stages of development (Exh. KEDNE/JFB-1, at 48). The Company contends that changes in the marketplace since the Department issued its decision have rendered the categorization of the transactions meaningless (id. at 49). Citing its recent portfolio management agreements as an example of the difficulty of assigning revenues to categories of transactions, Boston Gas claims that the policy established in D.P.U. 93-141-A no longer fits the reality of the marketplace (id.). In particular, the Company states that since the Department's Order in D.P.U. 93-141-A, it has entered into portfolio management arrangements that involve a set of interrelated transactions including capacity release and off-system sales (id.). According to the Company, these arrangements may involve transactions in more than one category, or a combination of categories (id.). According to Boston Gas, tracking and matching these transactions with the defined categories is impractical (id.).

In addition, Boston Gas argues that the current margin sharing framework does not provide adequate or appropriate incentives to maximize value for customers, because it is unrealistic to expect that the Company will have ever-increasing opportunities available to pursue value for customers (id. at 51). Boston Gas claims that, in the event of a multi-year

portfolio management agreement with payments levelized over the length of the contract, the Company's incentives are not aligned with the savings opportunities available to ratepayers (id. at 50-51). According to the Company, there is little or no opportunity for the Company to earn an incentive after the first year of a multi-year agreement, because the first-year payment sets the threshold goal for the subsequent years (id. at 51). The Company did not address the issue of non-firm margins in its initial or reply briefs.

3. Analysis and Findings

Non-firm margin sharing was established by the Department in D.P.U. 93-141-A. In that 1996 decision, the Department specified (1) the method by which margins are allocated by transaction, (2) a threshold above which LDCs can retain margins, and (3) the percentage to be retained by the LDCs. D.P.U. 93-141-A at 63-65. In the present case, Boston Gas proposes to change the method by which margins from non-firm transactions are calculated and retained by the Company. In particular, the Company proposes to remove the threshold above which the Company can retain margins and eliminate categories of transactions such as interruptible transportation, interruptible sales, capacity release and off-system sales. Instead, the Company proposes to pool all margins and return them to all customers, but leave the current margin sharing ratio (25 percent to the Company, 75 percent to customers) intact (Exh. KEDNE/JFB-1, at 52).

The rules for margin sharing were established as part of a generic investigation, and not in a company-specific rate case filing. In D.P.U. 93-141-A, numerous affected parties and limited participants had the opportunity to comment and submit margin sharing proposals to

the Department.[184] In approving the margin sharing framework, including the establishment of the transaction categories, the margin sharing formula, and the threshold structure, the Department balanced the risks and rewards of firm ratepayers and shareholders while providing LDCs with appropriate incentives. D.P.U. 93-141-A at 59-64. Now, Boston Gas proposes to eliminate the various transaction categories and the threshold structure, but to still apply the same 25/75 margin sharing formula. The proposed changes, particularly the elimination of the threshold without modification of the margin sharing ratio, will lead to greater margins for the Company at the expense of the ratepayers. This result is because under the existing structure, all margins earned at or below the threshold level are passed on to firm customers. If we were to eliminate the threshold requirement, the Company would be entitled to 25 percent of the margins that would otherwise go to the firm ratepayers. Accordingly, the Department rejects Boston Gas' proposal to change the existing framework for margin sharing.

Regarding the MOC's proposal to modify the existing terms and conditions to establish backup fuel supply requirements for interruptible customers, we find the establishment of such requirements to be unwarranted, to say the least. In D.P.U. 93-141-A at 46-47, in response to a proposal to require interruptible customers to have a backup fuel, the Department noted that,

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[184] The following were parties or limited participants in D.P.U. 93-141-A: the Attorney General, DOER, Bay State, Berkshire, Fall River Gas Company, Boston Gas, Colonial, Commonwealth Gas Company, Essex, Fitchburg, Massachusetts Municipal Wholesale Electric Company, the Energy Consortium, Distrigas of Massachusetts Corporation, New England Power Company and Massachusetts Electric Company, Enron Capital and Trade Resources Corporation, Algonquin Gas Transmission Company, Massachusetts Industrial Group, O&R Energy, Broad Street Oil and Gas Company, and TransCapacity Limited Partnership.

"LDC customers must be allowed the discretion to allocate funds in a way that allows them to maximize the benefits of such investment." Further, the Department found that customer dual fuel capability was not necessary. Id. at 47. The MOC has presented no new arguments or evidence to warrant a change in our policy. It is not a proper function of the Department to dictate how customers should conduct their affairs. There is no statutory basis for such command-and-control authority. It is not sound economics, either. Therefore, we do not accept the MOC's proposal to change the existing terms and conditions.

C. CGAC Expense Adjustments

1. Introduction

The Company proposes a number of adjustments that reduce the test year cost of gas from $345,823,335 to $298,932,065, for a net reduction of $46,891,270 (Exh. KEDNE/AEL-3, at 1). The Company proposes to reduce the test year cost of gas by $11,244,090 for gas costs associated with unbilled sales; $6,186,618 for non-firm gas costs; $4,236,326 for broker revenues; $356,857 for ECS gas costs; and $25,588,070 for CGA recoverable costs (id.). The Company also proposes to increase the test year cost of gas by $641,891 for non-firm margin retention and $78,800 for DSM incentive costs (id.).

2. Analysis and Findings

While the primary purpose of the COSS is to develop the revenue requirements for the distribution service, the Company starts with total costs (production and distribution) so that costs common to the production and distribution function can be properly allocated. D.T.E. 98-51 at 135. Department precedent requires the use of test year gas costs. Id. In

order to establish a representative level of gas costs, the Department allows adjustments to test year gas costs. D.T.E. 02-24/25, at 283-284. The Company's proposed adjustments to its test year cost of gas represent accounting entries and do not affect the collections generated from the CGA or LDAF (Exh. DTE 4-59). The intervenors did not address the Company's proposed adjustments to test year cost of gas. After review of the adjustments, the Department finds the Company's proposals to be reasonable, and accordingly we approve the proposed adjustments.

VIII. BOSTON GAS PBR PROPOSAL

A. Introduction

In D.P.U. 96-50 (Phase I) and D.P.U. 96-50-C, the Department established a PBR plan for Boston Gas to replace the traditional cost-of-service/rate-of-return method for setting the Company's distribution rates.[185] The initial term of the PBR plan was five years.

In the present proceeding, Boston Gas has proposed a new PBR plan. The components of the proposed PBR plan are similar to the components of the PBR plan approved in D.P.U. 96-50 (Exh. KEDNE/JFB-1, at 4).[186] The primary component is a price-cap[187] formula

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185 The Company was the first gas or electric utility company in the Commonwealth to be subject to a PBR plan. Prior to the Company's filing, the Department had considered and approved a price-cap PBR plan in D.P.U. 94-50.

186 The Company's proposed PBR plan differs from the PBR plan approved in D.P.U. 96-50 in the following respects: (1) the values in the price-cap formula, and (2) the absence of an accumulated inefficiencies factor.

187 A price-cap is one form of a PBR plan. It is a plan with a price ceiling, or a pre-set price (generally set by a regulatory agency) that cannot be exceeded by the company

(continued…)

that would apply to the Company's distribution service rates (id. at 20). Under Boston Gas' proposal, the Department would first establish distribution rates for the Company in the present proceeding based on cost-of-service ratemaking principles (id.). The approved rates would then be adjusted annually consistent with the price-cap formula (id. at 20, 26).

The Company proposes that the PBR plan be implemented for a term of five years, from November 1, 2003, through 2009 (id. at 27). For each year that the PBR plan is in effect, the Company would submit a compliance filing to the Department for implementation of new rates on November 1st each year (id.). The last rate adjustment would take effect on November 1, 2009 (id.). The PBR plan would continue beyond 2008, on a year-to-year basis, without further action by the Department, unless there is a base rate investigation initiated by (1) the Department on its own motion, (2) the Attorney General or other persons entitled under G.L. c. 164, § 93, or (3) the Company under G.L. c. 164, § 94 (id.). After the initial five-year term, the Company would notify the Department each year on or before June 1st beginning 2009, of its intention to submit a compliance filing on September 15th to continue the PBR plan for one more year (id.). Boston Gas' proposed PBR plan is described below in the following parts: (1) the components of the proposed price-cap formula – the inflation index, the productivity offset, and the exogenous cost factor; and (2) implementation aspects of the plan – the term of the PBR plan, the earnings sharing mechanism, rate design flexibility, and the service quality index.

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187 (…continued)
operating under the price-cap PBR plan (except for certain predetermined reasons). See, e.g., D.T.E. 01-56, at 7-29; D.P.U. 96-50 (Phase I) at 259-260.

B. The Price-Cap Formula

1. Boston Gas Proposal

a. Introduction

Under Boston Gas' proposal, the percentage change in the Company's price-cap index ("PCI") is defined by the following formula:[188]

$$\left(PCI_t / PCI_{t-1} \right) - 1 = \left(P_t / P_{t-1} - 1 \right) - X + Z_t$$

where P_t is an inflation factor in year t, X is the productivity offset (or the X-factor) and Z_t is the exogenous cost factor (or the Z-factor) which recovers the expense of certain exogenous factors that affect the Company's unit cost but are not accounted for in the inflation, or the X-factor (Exh. KEDNE/LRK-1, at 3). This formula is similar to the price-cap formula that the Department approved in D.P.U. 96-50 (id. at 1-5).[189] The productivity offset, X, has three

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188 Under the PBR plan approved in D.P.U. 96-50, rates for Boston Gas' monopoly services were governed by the following formula:

$P_{(t)} \leq P_{(t-1)} * (1 + I_{(t)} - X \pm Z_{(t)})$

where $P_{(t)}$ is the Company's weighted average price in year (t); $P_{(t-1)}$ is the Company's weighted average price in year (t-1); $I_{(t)}$ is a price inflation index for year (t); X is a productivity offset that would remain constant throughout the term of the plan, and $Z_{(t)}$) is an adjustment for exogenous costs that might occur in year (t).

See D.P.U. 96-50, at 261.

189 The formula is the same as used in D.P.U. 96-50, although the values of the factors of the formula differ. Further, the Company omitted an accumulated inefficiencies factor, which sets the value of that factor at zero.

components: (1) a productivity differential, (2) an input price differential, and (3) a consumer dividend (id.).[190] Boston Gas proposes to apply changes in the PCI within a rate class each year provided that (1) an index stayed within the PCI cap, and (2) no rate component increases by more than the rate of inflation (id. at 2).

b. Price Inflation Index

The Company proposes to use the gross domestic product ("GDP") price index ("GDP-PI") as measured by the United States Commerce Department as the price inflation index (P_t), in the price-cap formula (id. at 3-4).[191]

c. Productivity Offset

Boston Gas proposes that the productivity offset (or X-factor) be calculated as follows:

$$X = [(TFP^{IND} - TFP^{US}) + (W^{US} - W^{IND})] + CD$$

where

TFP^{IND} represents the total factor productivity ("TFP") trend for the Northeast gas distribution industry during the years, 1990-2000,

TFP^{US} represents the TFP trend for the United States economy during the years, 1990-2000,

W^{US} is an input price trend for the United States economy during the years, 1990-2000,

W^{IND} is an input price trend for the Northeast gas distribution industry during the years, 1990-2000, and

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190 The productivity differential and input price differential are also referred to sometimes as the productivity growth index and the input price growth index, respectively.

191 The GDP-PI is a measure of the United States economy-wide inflation in the prices of final goods and services produced in the economy.

CD is a consumer dividend factor.[192]

(id. at 3).

Boston Gas calculated the TFP index as the ratio of an output quantity index to an input quantity index (Exh. KEDNE/LRK-2, at 2).[193] The term (TFP^{IND} - TFP^{US}) is a measure of the productivity differential between the Northeast gas distribution industry and the United States economy and (W^{US} - W^{IND}) is a measure of the input price differential between the United States economy and the Northeast gas distribution industry (Exh. KEDNE/LRK-1, at 3).

The Company submitted a study, entitled "X-Factor Calibration for Boston Gas" ("productivity study"), in support of its proposed price-cap formula (Exh. KEDNE/LRK-2). The productivity study measures the trends in productivity and input price growth of LDCs located in the Northeast United States ("regional LDCs") and the United States economy during the years 1990 through 2000 (id.). The sample for the regional LDCs included 16 gas distribution companies, which together serve approximately 61 percent of all gas end users in the Northeast (id. at 9-10). Boston Gas stated that it used a regional definition of the gas distribution industry because of cost differences between Northeast gas distributors and distributors in the rest of the nation (id. at 8, n.3, citing Boston Gas Company, D.P.U. 96-50

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192 The consumer dividend factor, also known as a "stretch factor," "serves as a 'future' productivity factor because it is intended to account for expected future gains in productivity due to the move from cost-of-service regulation to performance-based regulation." D.P.U. 96-50 (Phase I) at 280.

193 The TFP is used to measure the efficiency with which firms convert production inputs to outputs. It is defined as output per unit of total factor input.

(Phase I) (1996); Exh. KEDNE/LRK-3).[194] The productivity study defines gas distribution operations to include all gas delivery services, customer account and customer information services, and other customer services that distributors provide to end users (Exh. KEDNE/LRK-2, at 3, 9).

The Company calculated the productivity and input price trends for the Northeast gas distribution industry and input price trends for the United States economy based on index logic (Exh. KEDNE/LRK-2, at 3, 14).[195] The multifactor productivity ("MFP") index for the private business sector, published by the Bureau of Labor Statistics ("BLS") of the United States Department of Labor ("DOL"), was used as a proxy for productivity trends for the United States economy (id. at 3; Exh. DTE 6-18).[196] Boston Gas calculated the input price trend for the United States economy as the sum of GDP-PI growth plus the MFP productivity trend (Exh. KEDNE/LRK-2, at 14).[197]

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194 Boston Gas defined the "Northeast" to include New England, New York, Pennsylvania, Delaware, and New Jersey (Exhs. KEDNE/LRK-3, at 11; AG-12-7).

195 Index logic stipulates that, in the long-run, the price trend of an industry that earns a competitive return is equal to its unit cost trend. Index logic also shows that an industry's unit cost trend can be expressed as the difference in input price and TFP trends (Exh. KEDNE/LRK-2, at 3, 14).

196 The Company argues that the private business sector accounts for about 76 percent of United States GDP and that the MFP index for the private business sector is "the most comprehensive measure that is available on the TFP growth of the United States economy" (Exh. DTE 6-18, at 1).

197 Data for the productivity study were compiled from the following sources: (1) the Uniform Statistical Report ("USR") filed by gas companies with the AGA; (2) DRI/McGraw Hill; (3) Whitman, Requardt & Associates; and (4) the BEA of the United States Department of Commerce (Exh. KEDNE/LRK-2, at 8).

According to the Company, the productivity study determined that the average annual growth rates for the output quantity and the input quantity indexes for the Northeast gas distribution industry between 1990 and 2000 were 1.42 percent and 0.89 percent, respectively (id. at 12). The corresponding TFP growth trend for the Northeast gas distribution industry between 1990 and 2000 was 0.53 percent (id. at 11-12).[198] The TFP growth trend for the United States private business sector over the same period was 0.98 percent (id.). This resulted in a TFP differential of negative 0.45 percent between the Northeast gas distribution industry and the United States economy for the period 1990 to 2000 (id.).[199]

The productivity study also determined that between the 1990 and 2000, input prices for the Northeast gas distribution industry grew at an average annual rate of 3.02 percent (id. at 14). In comparison, the input price trend for the United States economy was 3.10 percent during that same time period, resulting in an input price differential of 0.10 percent between the industry and the United States economy (id. at 14).[200] The Company added the negative 0.45 percent productivity differential to the 0.10 percent input price differential to calculate a productivity factor for Boston Gas, not including the consumer dividend factor, equal to negative 0.35 percent (Exh. KEDNE/LRK-1, at 2).[201]

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198 The TFP growth trend for the Northeast gas distribution industry was calculated as (1.42 - 0.89) = 0.53 percent.

199 The productivity differential was calculated as (0.53 - 0.98) = negative 0.45 percent.

200 The input price differential was calculated as (3.10 - 3.02) = 0.08 percent. Boston Gas rounded it to 0.10 percent (Tr. 10, at 1255).

201 The Company states that the results of the productivity study also showed that on

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The Company submitted a second study, entitled "The Cost Performance of Boston Gas" ("cost study") in support of its proposed price-cap formula (Exh. KEDNE/LRK-3). The cost study measured Boston Gas' overall cost efficiency from 1993 to 2000 using econometric cost modeling (id. at 1).[202] The cost study defines the total cost of gas distribution services, as distinct from the cost of gas procurement services, to include the cost of plant ownership, operation, and maintenance (id. at 2). The cost study is based on a sample of 43 distribution companies nationwide, including most of the nation's larger distributors (id. at 2-3).[203] The 43 distribution companies in the sample together serve approximately 52 percent of all gas end users in the United States (id. at 3).[204] The cost study specifies a cost function which shows

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201 (…continued)
average, between 1990 and 2000, gas customers in the Northeast grew by 1.1 percent per year while delivery volumes grew by 2.5 percent per year. Similarly, the quantity of capital services for the Northeast gas distribution industry grew, on average, by about 1.9 percent annum while the quantity of other operations and maintenance ("O&M") inputs increased by 1.6 percent per year. In contrast, the quantity of labor services fell by 2.7 percent annually between 1990 and 2000 (Exh. KEDNE/LRK-2, at 20-23).

202 The database used by PEG, the consultants who conducted the cost study, was begun in late 1994. At that time, 1993 was the most recent year for which data were available (Exh. DTE 6-32).

203 Forty percent of the distributors included in the sample came from the Northeast (Exh. KEDNE/LRK-3, at 3).

204 The primary source of data for the cost study was the USR. The other sources of data for the study were the following: (1) DRI/McGraw Hill; (2) Whitman, Requardt & Associates; (3) the BEA; and (4) BLS (Exh. KEDNE/LRK-3, at 3).

the relationship between the cost of a utility and quantifiable business conditions in the utility's service territory (id. at 6).[205]

According to the Company, the cost study determined that (1) the average total cost for Boston Gas was approximately 80 percent of the sample mean, (2) the number of customers served by Boston Gas was approximately 70 percent of the sample mean, and (3) Boston Gas' throughput was approximately 80 percent of the sample mean (id. at 12). Regarding input costs, Boston Gas' labor and capital prices were 13 percent and nine percent above their respective sample means (id.). The cost study also showed that 44 percent of the Company's distribution mains were cast iron, making the Company's distribution system the most cast-iron intensive system of all the companies in the sample (id.).

The cost study also determined that gas distribution costs in the Northeast were 5.9 percent higher than the average cost for distributors in the sample (id. at 14). This result was statistically significant at the 90 percent confidence level (id. at 14-16). The cost study determined that during the 1993-2000 sample period, the Company's average cost was approximately 27 percent below its predicted value (id. at 16). Boston Gas included a PBR dummy variable in the econometric cost model to estimate the independent effect of the Company's initial PBR plan on its costs (id. at 11).[206] The coefficient of the PBR dummy

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[205] Boston Gas defines business conditions as "aspects of a company's operating environment that influence its activities but cannot be controlled" (Exh. KEDNE/LRK-3, at 6).

[206] The PBR dummy variable in the econometric cost model had a value equal to one for each year that the Company operated under its initial price-cap plan (1997-2000), and a

(continued…)

variable was negative 0.3 percent and statistically significant at the 90 percent confidence level (id. at 14-16). The Company interprets the significance of the PBR dummy variable to mean that, "after controlling for each of the other business conditions in the model, [Boston Gas'] costs declined by 0.3 percent during the years when PBR [plan] was in effect" (id. at 16).[207]

In summary, the Company argues that the cost study determined that Boston Gas was a significantly superior cost performer during the 1993-2000 period, because it ranked second in the cost study (Exhs. KEDNE/LRK-1, at 15; KEDNE/LRK-3, at 16). Based on the results of the cost study, and the Company's judgment as to the appropriate level of the consumer dividend under the current PBR plan, Boston Gas proposed a consumer dividend factor of 0.15 percent (Exhs. KEDNE/LRK-1, at 2, 14-15; KEDNE/JFB-1, at 24-25; AG 7-11). The 0.15 percent consumer dividend factor is one half of the 0.3 percent cost reduction that Boston Gas attributes to the PBR plan under D.P.U. 96-50 (Tr. 10, at 1215-1216).

Based on the results of the productivity and cost studies, and on the Company's judgment as to the appropriate level of the consumer dividend going forward, Boston Gas set the productivity offset, or X-factor, at negative 0.20 percent (i.e., the sum of a productivity

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206 (…continued)
value equal to zero for other years and for every other company in the sample (Exh. KEDNE/LRK-3, at 11).

207 The Company tested and rejected the hypothesis that Boston Gas was an average (or inferior) cost performer at the 99 percent confidence level (Exh. KEDNE/LRK-3, at 16).

differential of negative 0.45 percent, an input price differential of 0.10 percent, and a consumer dividend of 0.15 percent) (Exh. KEDNE/LRK-1, at 2).[208]

2. Positions of the Parties

a. Attorney General

The Attorney General argues that the Department should reject Boston Gas' proposed PBR plan because it fails to meet the Department's goals and standards for approval of an incentive ratemaking proposal and is unfair to ratepayers (Attorney General Brief at 107-108, citing Incentive Regulation, D.P.U. 94-158, at 57 (1995)).[209] The Attorney General characterizes Boston Gas' proposed PBR plan as an "inflation-plus" rate plan which more resembles a cost of living adjustment ("COLA") for the Company than PBR

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[208] A productivity offset of negative 0.2 percent means that Boston Gas' distribution service rates would increase higher than the rate of inflation by 0.2 percent every year during the term of the PBR plan.

[209] The Attorney General states that the Department requires a utility seeking approval of an incentive proposal to demonstrate that its approach advances "the Department's traditional goals of safe and reliable energy service and. . .promotes the objectives of economic efficiency, cost control, lower rates, and reduced administrative burden in regulation." (Attorney General Brief at 107-108, citing D.P.U. 94-158, at 57.

(id. at 107).[210] The Attorney General contends that the Company's COLA presents significant risks to customers and little prospect of benefits and will most likely result in customers paying more, not less, than they would under cost of service ratemaking (id.).

According to the Attorney General, Boston Gas' PBR plan is a "hybrid" between a cost of service model and an incentive model that seeks to maximize cast-off rates that are then increased automatically for years under an inflation-plus PBR formula (id. at 108; Attorney General Reply Brief at 55). The Attorney General claims that Boston Gas appears to have delayed plant improvements during the first several years of its initial PBR plan, and then has accelerated capital improvements before the end of the test year to maximize rate base (Attorney General Brief at 108, citing Exh. DTE 6-1). In addition, the Attorney General argues that the Company appears to have increased its expenses during the test year, by, among other means, accepting large allocations from affiliates (id. at 108). Furthermore, the Attorney General argues that Boston Gas has offered no convincing argument that its hybrid PBR plan would help the Department achieve its traditional ratemaking goals better than they would be achieved under the Department's existing rate setting methods (id.). In effect, the Attorney General asserts that Boston Gas is seeking the "best of both worlds" with a

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210 The Attorney General claims that Boston Gas' PBR plan is the nation's only "inflation-plus" PBR plan (Attorney General Reply Brief at 54). According to the Attorney General, under Boston Gas' proposal, gas delivery rates will increase at a rate of 0.2 percent more than the general inflation rate, i.e., [(GDP-PI) - (-0.2%)] (Attorney General Brief at 109, citing Exh. KEDNE/LRK-1; Attorney General Reply Brief at 54).

$61 million proposed rate increase that are then increased automatically for years (id., citing Exh. DTE 6-1).

The Attorney General states that Boston Gas' PBR plan makes no allowance for the expiration of the ten-year rate freeze ordered by the Department for Essex and Colonial as part of their mergers (id., citing Tr. 10, at 1234-1237; Tr. 11, at 1340-1343, at 1379-1381). He explains that under the system of cost accounting allowed by the Department in those cases, Essex and Colonial retain the synergies from the mergers to pay for merger-related costs (Attorney General Brief at 108, citing D.T.E. 98-27, at 69; D.T.E. 98-128, at 90-96). The Attorney General claims that once Eastern and Essex's rate plans end, costs to Boston Gas should fall dramatically as it also continues to see the benefits of those mergers (Attorney General Brief at 108). The Attorney General argues that Boston Gas' customers should share in the benefits of these mergers after the rate freeze period; however, the Company does not share those cost savings with its customers in any way in the proposed PBR plan, resulting in a windfall for Boston Gas at the expense of its customers (id. at 108-109).

The Attorney General criticizes the research design of the productivity study which Boston Gas presented in support of the X-Factor calibration on several grounds (id. at 110-111). First, the Attorney General argues that Boston Gas did not provide sufficient justification for why it limited the sample to 16 large gas distribution companies in the Northeast, nor did the Company show that the 16 companies constituted a representative sample of gas distribution companies in the Northeast (id. at 110, citing RR-DTE-76; Exh. AG-41, at 6). Second, the Attorney General claims that Boston Gas did not show that the

factors that result in productivity growth are different in the Northeast than they are in the rest of the country (Attorney General Brief at 110, citing Exh. AG-41, at 5).[211] Third, according to the Attorney General, the errors in cost data in the first and last years for some of the companies in the sample could affect the results of the productivity study (id., citing Exhs. AG-41, at 5; AG-12-10; AG-31-11; Tr. 10, at 1178-1182).[212] Fourth, the Attorney General claims that the measure of output used in the productivity study does not encompass the introduction of new products, and the improvement in service reliability (Attorney General Brief at 111). Fifth, according to the Attorney General, the 1990 to 2000 study period did not correspond perfectly to a business cycle (id. at 110-111, citing RR-DTE-76). Because growth during this most recent business cycle was higher than normal, the Attorney General argues that the 1990 to 2000 period may not show normal productivity growth for the gas industry (id. at 111-112, citing RR-DTE-76). According to the Attorney General, this calls into question the accuracy of Boston Gas' productivity study to predict the normal future growth in gas

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211 According to the Attorney General, Boston Gas seems to suggest that the Department should accept a Northeast definition of the gas distribution industry used in the productivity study because the Department accepted a regional definition of the gas distribution industry for the productivity study conducted for the Company's last rate case, D.P.U. 96-50. The Attorney General contends that the Company's argument is untenable because the productivity studies presented in D.P.U. 96-50 were quite different from the single Northeast productivity study presented in this proceeding (Attorney General Reply Brief at 58-59).

212 According to the Attorney General, there were errors in the data that Boston Gas used in the original cost study. The Attorney General claims that during the course of this proceeding, the Company "corrected" several errors in the data. Because the "corrections" were not incorporated in the original cost study, the results of the original study are distorted (Attorney General Reply Brief at 57, citing Exh. AG-31-11; Tr. 11, at 1434-35).

utility productivity (Attorney General Reply Brief at 60, citing RR-DTE-76). Sixth, the Attorney General claims that the inclusion of actual franchise taxes in non-labor O&M costs could cause a distortion in the coefficients produced by the econometric cost model (Attorney General Brief at 111, citing RR-DTE-76). Finally, the Attorney General claims that the largest single problem with the productivity study is its estimation of capital cost (id.).

According to the Attorney General, Boston Gas estimated the cost of capital stock (plant) for each utility using the implicit assumptions that plant value in 1983 was the same age and had been installed at the same rate for all utilities across the country (id.). Because this assumption is not correct, the Attorney General claims that the Company's procedure tends to understate the value of older plant, such as Boston Gas' (id.). In addition, the Attorney General argues that use of a single Handy-Whitman index[213] for different utilities (varying only by regional differences in the Handy-Whitman index) failed to recognize the different proportions of plant in the different utilities, (i.e., amount of storage, transmission mains, distribution mains, services, etc.) (id.).

The Attorney General rejects Boston Gas' claim that the calculation of the 1983 benchmark value of capital stock is not problematic because the coefficient of the Northeast dummy variable in the econometric cost model was positive, and not negative as should be expected had the study understated capital costs of older utilities (Attorney General Reply Brief

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[213] The Handy-Whitman Index is an index of public utility construction costs published by Whitman, Requardt & Associates (Exhs. KEDNE/LRK-2, at 8, 24; AG-7-20, Att.).

at 59).[214] The Attorney General contends that if utilities in the Northeast were uniformly older than utilities in the rest of the country, the cost understatement for older plants would have a negative effect, but not necessarily produce a negative coefficient for the Northeast dummy variable (id. at 59, citing Exh. AG-41; RR-DTE-76; Tr. 26, at 3634-3635).[215]

The Attorney General claims that the econometric cost models making up the study are complex, unreviewable, and suffer from a number of methodological flaws (Attorney General Brief at 111, citing RR-DTE-76; Exhs. KEDNE/LRK-2; KEDNE/LRK-3).[216] These flaws include problems with the measurement of cost and the exclusion of a number of variables from the model that may influence costs (id., citing RR-DTE-76). The Attorney General argues that Boston Gas included in the capital cost measurement, actual taxes paid by each utility. Because Boston Gas pays a much lower amount of taxes than most of the utilities from the Northeast relative to its capital plant costs, the results of the study are biased to make

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214 In the cost study, Boston Gas included a Northeast dummy variable in the econometric cost model to test whether there are differences in distribution costs between the Northeast and the rest of the country. The dummy variable had a value equal to 1 for every gas distributor in the sample headquartered in New England, New York, Pennsylvania, or New Jersey, and a value equal to zero for all other gas distributors (Exh. KEDNE/LRK-3, at 11).

215 The Attorney General claims that the assumption regarding Northeast utilities is too simplistic, because Northeast utilities "do not uniformly have plant of the same, older vintage, but rather there is a great deal of variance among them, and some utilities in the rest of the country also have older plant. Thus Northeast utilities may tend to be older, but the lack of uniformity in this characteristic is another reason why the model cannot prove that the capital stock numbers are correct" (Attorney General Reply Brief at 59-60).

216 The Attorney General states that the cost study does not even examine Boston Gas' actual costs (Attorney General Brief at 112, citing RR-DTE-76).

Boston Gas appear to be a low-cost utility and a "superior cost performer" when, in fact, it is not (id. at 112, citing Exhs. DTE 76; AG-41, at 16). Furthermore, the Attorney General asserts that the inclusion of actual taxes in costs is not consistent with the theoretical backing of the model (Attorney General Reply Brief at 61, citing Exh. KEDNE/LRK-2, App.).[217]

The Attorney General disputes the Company's contention that because Boston Gas has already increased efficiency there is little room for additional improvement (Attorney General Brief at 112, citing Exh. KEDNE/LRK-1, at 24). The Attorney General argues that if Boston Gas is an efficient cost performer, as the Company claims, and cannot improve its productivity growth rate under the proposed PBR plan, then there is little justification for using PBR rather than standard cost of service ratemaking for the Company (id. at 113). According to the Attorney General, there is much evidence that productivity gains will accelerate and that economic efficiency will increase as the Company continues to (1) adjust its operations in response to the incentives created by PBR plan and the mergers and (2) reacts more efficiently to technological change (id. at 112-114, citing Exhs. AG-41, at 23; KEDNE/LRK-6, at 59).[218] The Attorney General claims that there is empirical evidence that Boston Gas has not instituted

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217 The Attorney General claims that according to the Company's productivity study, taxes should be one of the components of capital service price index, and not a capital cost (Attorney General Reply Brief at 61, n.56, citing Exh. KEDNE/LRK-2, App.).

218 The Attorney General states that there is theoretical support for continued and even increased productivity gains, citing an article provided by Boston Gas from the Electricity Journal titled, "Efficiency as a Discovery Process: Why Enhanced Incentives Outperform Regulatory Mandates." The article states that "the achievement of performance gains is first and foremost a 'discovery process' in which more efficient operating and superior use of technology are learned over time" (Attorney General Brief at 113, citing Exh. KEDNE/LRK-6, at 59).

many easy productivity improvements related to energy saving software activation and is planning to make a number of substantial efficiency improvements starting in 2003 (id. at 113, citing Exh. KEDNE/JCO-14; RR-AG-77; RR-AG-54; Tr. 18, at 2464-2466).[219]

The Attorney General, therefore, urges the Department to reject Boston Gas' proposal, or allow a PBR plan for the Company only if it is reviewable and not unduly complex, and has at least a one percent consumer dividend to allow consumers to have some share of the savings (id. at 114, citing RR-DTE-72).[220] In addition, the Attorney General suggests that customers should also be allowed to benefit through an earnings sharing plan designed such that sharing is of "excess earnings, not earnings below the authorized return, because the Company has far greater knowledge of its data, and ability to control, and even manipulate, its earnings figures, especially after multiple mergers" (id. at 112-114, citing RR-DTE-72). Finally, the Attorney

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[219] The Attorney General claims that the California Public Utilities Commission ("CAPUC") justified increasing the consumer dividend because productivity improvements do not occur all at once, but take time to implement (Attorney General Brief at 113-114, citing Order CAPUC docket 99-05-030, at 53).

[220] The Attorney General rejects Boston Gas' argument that the PBR models presented in this proceeding are not complex and are reviewable because the Department reviewed analogous models in the Company's last PBR proceeding. According to the Attorney General, the two proceedings use different models and different databases, include different utilities, and define output differently. Also, the models in this proceeding have been explored in more depth than in the previous proceeding. The Attorney General claims that the literature supporting the models address very complex mathematical techniques, and do not address many of the significant problems that are extremely important when the studies are used to compare the gas industry to other industries, and to compare one gas utility to others. Therefore, the Attorney General argues that the results of the previous case do not provide full justification for using the results in this case (Attorney General Reply Brief at 56, citing Exhs. AG-7-12; KEDNE/LRK-2; KEDNE/LRK-3; Tr. 10, at 1127).

General suggests that even if a PBR plan is approved for Boston Gas, it should not be applied to the Company's proposed pension and PBOP reconciliation adjustment mechanism because that would double-count cost changes (id. at 114, citing RR-DTE-72).

b. DOER

DOER argues that the PBR plan proposed by Boston Gas fails to meet the Department's standard of review in the areas of economic efficiency, cost control, lower rates, and reduced administrative burden (DOER Brief at 7, 13, citing D.P.U. 94-158, at 58). DOER claims that, in developing its PBR plan, Boston Gas relied on incorrect assumptions and studies, and inaccurate data concerning productivity and cost containment, making the Company's cost model inherently unreliable (id. at 7, 13-19). According to DOER, the Company failed to provide any empirical basis for specific components of the PBR plan (id. at 7, 13-19).

DOER argues that, contrary to the Company's position, the PBR plan approved in D.P.U. 96-50, which is the basis for the Company's current proposal, has not been effective in inducing productivity improvements (id. at 14). DOER claims that, except for a nominal increase in productivity in 1998, Boston Gas' productivity suffered significantly during the 1990 and 2001 period, and worsened between 1997 through 2001 when the first PBR plan was in effect (id. At 14-15, citing RR-DOER-1).[221] DOER further claims that Boston Gas failed to explain why it did not adjust changes in its input usage to correspond with changes in its output

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[221] DOER states that it based its conclusion on an analysis of the data provided by Boston Gas in its filing to the Department and elicited by DOER and the Department through record requests. Therefore, any inaccuracy in its conclusion should be attributed to the Company for failing to provide complete and accurate information to the Department and intervenors (DOER Reply Brief at 4).

if the goal of a PBR plan was to mimic market forces, whereby firms adjust their input usage based on demand trends or forecasts (DOER Reply Brief at 5).[222]

DOER disputes Boston Gas' claim that labor cost savings constituted the primary source of the cost savings achieved by the Company under its previous PBR plan (DOER Brief at 16, citing Exh. KEDNE/LRK-1, at 21, 3-19). According to DOER, Boston Gas' labor costs actually increased during the term of the first PBR plan (id., citing Tr. 13, at 1627, 19-24; RR-DOER-1). DOER contends that the assumptive flaws demonstrated in the Company's cost study undermine the credibility and the validity of implementing the proposed PBR plan (id. at 17). DOER argues that Boston Gas' poor cost performance under the first PBR plan is material and should be considered relevant to any going-forward analysis of incentive regulation for the Company (DOER Reply Brief at 3).

With regard to the price-cap formula, DOER claims that Boston Gas has failed to provide sufficient empirical basis or reliable evidence to support the proposed consumer dividend (DOER Brief at 17-18). According to DOER, the basis for the 0.15 percent consumer dividend proposed by the Company is the cost study finding that Boston Gas has eliminated obvious inefficiencies from its operations and, therefore, can offer only incremental improvements in its overall performance under the proposed PBR plan (id., citing Exhs. KEDNE/LRK-1, at 24-25; AG 7-11). DOER argues that because the data produced by Boston

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222 DOER claims that excluding the year 2001 as an outlier, the average annual growth rate in the output quantity index over the 1999-2001 period was 0.34 percent, compared to 1.35 percent for the input quantity index. This means that Boston Gas' first PBR plan failed to provide sufficient incentive for the Company to adjust its input usage to the apparent declining trend in sales (DOER Reply Brief at 5).

Gas during the hearings contradict the Company's conclusions concerning its cost performance under D.P.U. 96-50, it is important that the method employed by the Company to establish the consumer dividend be examined by the Department (id., citing Exh. MDFA 3-2). Furthermore, DOER contends that the Company's two PBR witnesses provided contradictory evidence on the empirical basis for the consumer dividend, making it difficult to discern any consistent method used to derive the 0.15 percent consumer dividend (id. at 18).[223]

DOER states that, while it supports the continued use of PBR, the faulty assumptions, inaccurate data, and lack of a consistent method in designing the PBR plan, taken together, make Boston Gas's proposed PBR plan inherently unreliable (id. at 19). According to DOER, the Company's PBR plan, as designed, will not be effective in implementing the Department's goals and objectives for incentive regulation (id. at 32). Therefore, DOER proposes the price-cap formula[224] described below (id. at 19-20, 32-33).

$$PCI_t / PCI_{t-1} - 1 = \left(P_t / P_{t-1} - 1 \right) - X + Z_t$$

where, P_t is the inflation factor as indicated by the producer price index ("PPI") for United States natural gas utilities (transportation only) produced by the BLS, X = $(TFP^{BG} - TFP^{IND})$ is

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223 According to DOER, one of the Company's two PBR witnesses testified that the 0.15 percent consumer dividend proposed by Boston Gas was based on empirical and historical evidence, while the other witness stated that there was no empirical basis for the consumer dividend (DOER Brief at 18, citing Exh. DOER 2-2; Exh. DTE 6-8; Tr. 10, at 1259, 12-20; Tr. 11, at 1299).

224 DOER submitted the PBR plan for the first time on brief.

the X-factor, where TFP^{BG} is the total factor productivity trend for Boston Gas and TFP^{IND} is total factor productivity trend for the gas distribution industry; and Z_t is the exogenous cost factor, or the Z-factor (id. at 22).

DOER argues that its alternative PBR plan is simpler because it removes a number of irrelevant elements from the Company's proposed price-cap formula (id. at 23). DOER states that its alternative PBR plan eliminates (1) the TFP for the United States because the comparison of Boston Gas' productivity to the peer group provides a more relevant analysis of the Company's performance;[225] (2) the input price trend for the gas distribution industry because the producer price index for United States natural gas companies ("PPI-NG") captures price inflation for the gas industry more effectively than the GDP-PI;[226] (3) the input price

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225 DOER states that in D.P.U. 94-50, at 172, the Department disallowed the use of the company's historic productivity because of the expectation that the company's prices would change at the same rate as the industry average productivity change and the concern that productivity offsets would be based on the company's productivity would act as a disincentive to improving productivity. DOER argues that these considerations, while appropriate for D.P.U. 94-50, simply do not apply to Boston Gas. First, Boston Gas prices have not changed at the rate of industry average productivity changes, as the Company's own data demonstrate. Second, DOER's alternative proposal recommends that Boston Gas be given the investment of capital necessary to improve and incent productivity, eliminating the possibility of dampening incentives based upon Boston Gas's own productivity. Finally, given the facts specific to Boston Gas, the above TFP formulation would be more effective than reliance upon the prior structure. Using historic data as a benchmark for company performance is within Department precedent, as demonstrated in Boston Gas's approved Service Quality Plan in Boston Gas Company, D.T.E. 02-37 (2002) (DOER Brief at 23, n.20).

226 DOER claims that Boston Gas' objection to the use of PPI-NG as the inflation index in the PBR formula is without merit for the following reasons. First, both the PPI-NG and the GDP-PI are output-based, national indices. Second, the Company's proposed price-cap formula adjusts the X-factor, but not the GDP-PI. Such a one-time

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trend for the United States economy for the same reason; and (4) the consumer dividend because the productivity comparison accounts for the differential productivity expectations for the Company (id. at 23).

DOER states that it has eliminated the consumer dividend factor from its PBR plan because (1) it is difficult to calculate with any certainty; (2) the theoretical and methodological basis for the calculation of the consumer dividend is tenuous; and (3) Boston Gas' proposed PBR plan does not allow for firms that are in need of capital for productivity-enhancing investments (id. at 23-24). DOER states that under its proposal, the benefit of the consumer dividend is incorporated within the productivity factor (DOER Brief at 24).[227] DOER further states that the PPI inflation index for United States natural gas utilities meets the Department's overall goals and objectives for incentive regulation more effectively than the GDP-PI, and affords greater consistency with Department precedent because the PPI allows implementation

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226 (…continued)
adjustment over the term of the PBR plan does little to capture the relationship between inputs and outputs or to take into account regional differences for the natural gas industry. Third, the fact that adjustments and changes may be made to the PPI-NG is not a strong enough reason against its use because such changes are not idiosyncratic to the PPI-NG but are endemic among price indexes in general. Finally, the PPI-NG demonstrates an acceptable level of volatility, is more reflective of the realities of the natural gas industry than the GDP-PI, and therefore, is consistent with the Department's goals and objectives of incentive regulation, contrary to the Company's claim (DOER Reply Brief at 5, citing Boston Gas Brief at 182-185).

227 Under DOER's PBR plan, the X-factor for Boston Gas will be negative 1.38 percent, i.e., $X = (TFP^{BG} - TFP^{IND}) = (-0.85 - 0.53) =$ negative 1.38 percent (DOER Brief at 24, n.21).

of an inflation index that more closely tracks the natural gas industry's prices and costs (id. at 27, citing Exh. KEDNE/LRK-1, at 4).[228]

In summary, DOER claims that its proposal (1) incorporates Boston Gas' specific circumstances, (2) promotes the Department's goals of incentive regulation, (3) is a broad-based incentive mechanism that focuses on comprehensive results, (4) provides rewards rewards for improved performance that are more closely akin to those provided by the competitive market; (5) provides for exogenous cost adjustments consistent with the Department precedent;[229] and (6) incorporates well-defined, measurable indicators of performance that are more acutely tied to Boston Gas' performance (id. at 19-22). DOER

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228 DOER states that while the GDP-PI has been relied upon historically by the Department, it is not an accurate index of changes in the production factors faced by any one particular industry; it is a proxy. Conversely, a primary use of the PPI-NG is to measure real growth in output for the industry, which the GDP-PI does not effectively capture. Because the PPI accurately foreshadows subsequent price changes for industry and for consumers, it is relied upon as an economic indicator by Congress and the Federal Reserve for formulating fiscal and monetary policies. DOER explains that the PPI-NG is more accurate and relevant in this proceeding than the GDP-PI, and that it is just as available, just as timely, and more directly applicable to Boston Gas than the GDP-PI (DOER Brief at 27, n.24, citing DTE-RR-36; Mark Newton Lowry, Ph.D., Lawrence Kaufmann, Ph.D., Lullit Getachew, Ph.D.; Price Control Regulation in North America: Role of Indexing and Benchmarking; Pacific Economics Group (2002) at 6 which have endorsed the use of alternative macroeconomic inflation measures, including the GDP-PI, the CPI, and the PPI; http://www.bls.gov/ppi/ppifaq.htm).

229 DOER's exogenous cost proposal is similar to that approved in D.P.U. 96-50, at 291-292 and D.T.E. 01-56, at 25-26.

further claims that its alternative proposal is consistent with all accounting standards and completely acceptable within the financial community (id. at 21-22).[230]

c. Bay State

Bay State supports Boston Gas' PBR proposal (Bay State Brief at 1). Bay State states that the proposal is consistent with the Department's standards for incentive ratemaking, which requires that an incentive proposal must demonstrate that its approach is more likely than cost of service regulation to advance the Department's goals of safe and reliable energy and to promote the objectives of economic efficiency, cost control, lower rates, and reduced administrative burden in regulation (id. at 1, 3-4, citing D.P.U. 94-158, at 57, 66). According to Bay State, Boston Gas' initial PBR plan approved in D.P.U. 96-50 was successful in containing Boston Gas' costs, increasing efficiencies, and reducing the need for administratively wasteful and time-consuming rate proceedings (id. at 4, citing Exhs. KEDNE/JFB-1 at 4, 21; DTE 6-1; DTE 6-4; DTE 6-15).

Bay State argues that in the ten years prior to D.P.U. 96-50, Boston Gas was able to demonstrate a legitimate basis for a base rate increase every 2.5 years, together totaling approximately $70 million (id. at 4, citing Exh. DTE 6-4; D.P.U. 96-50 (Phase I); D.P.U. 93-60; D.P.U. 90-17/18/55; D.P.U. 88-67). Boston Gas' expenses (in nominal dollars) during

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230 DOER contends that although the GDP-PI, by its nature, would tend to be more stable, the PPI-NG, being a national index, has shown great stability while not sacrificing the measurement of cost pressures that gas utilities may face. The slight increase in volatility in the PPI-NG, according to DOER, is worth the use of a more accurate indicator of gas utility-related costs and is, therefore, more consistent with Department authority and precedent (DOER Brief at 28).

the ten years prior to D.P.U. 96-50 rose by 4.9 percent per annum, on average (id. at 4). However, between 1996 and 2002 when Boston Gas operated under a PBR plan, the Company's expenses (in nominal dollars) rose by just 2.3 percent per annum (id., citing Exh. DTE 6-1(a)). Bay State asserts that in real dollars, these amounts were 2.1 percent and 0.6 percent, respectively (id., citing Exh. DTE 6-1). Bay State claims that the estimated total cost savings attributable to Boston Gas' PBR plan under D.P.U. 96-50 was $4.065 million (id., citing Exhs. DTE 6-51; DOER 2-12).

Regarding the consumer dividend proposed by Boston Gas, Bay State states that it agrees with the Company's assertion that "it will become more difficult to achieve incremental productivity gains in [Boston Gas'] next PBR plan" (id. at 7, citing Exhs. KEDNE/LRK-1, at 14; DOER 2-2). Bay State argues that for every year that a company operates under a PBR plan, efficiencies (actual, not theoretical) have been maximized and the consumer dividend must be reduced to account for this fact (id., citing Exh. KEDNE/JFB-1, at 24).

According to Bay State, the consumer dividend in a PBR plan captures future gains in productivity resulting from the change in regulatory paradigm from cost-based ratemaking to incentive rate setting (id. at 6, citing Exh. AG 11-54; D.P.U. 96-50 (Phase I) at 280). Therefore, absent a demonstrable, pro forma-type adjustment for technological innovation, the most appropriate value for a consumer dividend will be zero as PBR regulation moves forward into the future (id. at 6-7, citing Exh. KEDNE/LRK-1, at 6; Exh. AG 30-2). Bay State contends that the consumer dividend of 0.15 percent proposed by Boston Gas is reasonable, given the Company's generous assessment of efficiencies that it can achieve in the next five

years (id. at 7, citing Exhs. KEDNE/JFB-1, at 24; AG 11-54; AG 30-2; DTE 8-5; DOER 2-2). Bay State argues that the incentives to pursue (even marginal) productivity gains and to avoid base rate proceedings over a prolonged period, which are at the core of every PBR plan, will continue to provide benefits for ratepayers and utilities over cost of service regulation (id. at 7-8, citing Exh. DTE 6-6). Bay State urges the Department to find that, while efficiency gains may be had during Boston Gas' second term of PBR, any gains will be reduced in magnitude, and the calculation of the consumer dividend should be adjusted accordingly (id. at 7, 8; citing Exhs. AG 30-2; DTE 6-8).

Bay State concludes that Boston Gas' proposed PBR plan is consistent with law, is consistent with the theories of market-based regulation and enhanced competition, is consistent with the utility's obligation to safeguard system reliability, integrity, and policy objectives, will reward performance while addressing costs outside the Company's control, will focus on results, incorporates defined measures of performance, is an appropriate length, and reduces regulatory and administrative cost (id. at 6, citing D.P.U. 94-158, at 66). Bay State urges the Department to approve Boston Gas' proposed PBR plan as reasonable (id. at 6).

With respect to ratemaking proposals in general, Bay State states that, irrespective of the outcome of this proceeding, the Department should investigate each utility's proposed rate construct on a case-by-case basis, regardless of whether it incorporates elements of a prior approved plan or initiates new rate proposals for approval (id. at 2, 9). Bay State urges the Department to consider alternative arguments as to how the Department's incentive regulation objectives may be achieved (id. at 9, citing D.P.U. 94-158, at 9, 52-66). Bay State argues that

if alternative methods can be shown to advance the Department's traditional goals of safe, reliable and least-cost service and to promote the objectives of economic efficiency, cost control, lower rates and reduced administrative burden in regulation, such methods should be fully evaluated (id. at 9-10, citing RR-DTE-41; Exhs. DTE 6-15; MDFA 3-3; Incentive Regulation, D.P.U. 94-158, at 54-55). Bay States urges the Department to reaffirm its prior policy on incentive ratemaking (id. at 10, citing Performance Based Regulation For Distribution Companies (Report Prepared for NARUC), The Regulatory Assistance Project at 18-19, 42, December 2000).

d. Boston Gas

Boston Gas contends that the record demonstrates that the Company has proposed a well-balanced PBR plan that is consistent with the Department's directives in D.P.U. 96-50 and comports with sound regulatory and economic policy (Boston Gas Brief at 162). The Company states that the proposed PBR plan provides Boston Gas with the incentive and opportunity to manage costs and increase productivity so that the need for a base-rate proceeding may be avoided for a prolonged period of time (id., citing Exh. DTE 6-4).

Boston Gas claims that, except for the values assigned to particular components of the price-cap formula, the Company's proposed PBR plan is identical in all respects to the PBR plan approved by the Department in D.P.U. 96-50 and D.P.U. 96-50-C (Boston Gas Reply Brief at 92).[231] Boston Gas contends that, with the exception of the values assigned to the

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[231] Boston Gas states that it did not include an accumulated inefficiencies factor in the productivity offset because (1) the Department has stated that accumulated inefficiencies (continued…)

components of the price-cap formula, there can be no dispute that the proposed PBR plan complies with Department regulation and precedent (id. at 92).[232]

Boston Gas rejects the Attorney General's arguments that the econometric cost model and the model used in calculating the TFP trends are "unduly complex" and "unreviewable" (Boston Gas Brief at 185-187). The Company states that both models are identical to the models presented in support of its PBR plan in D.P.U. 96-50, and that the Department was able to review and evaluate the models in that proceeding (id.).[233]

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231 (…continued)
"should be accounted for in the first term of the PBR plan" (Exh. DTE 6-20, citing D.P.U. 94-50, at 166-167). Also, the Company argues that the price-cap PBR plan that the Department approved for Berkshire did not include an accumulated inefficiencies factor even though it was the first PBR plan for Berkshire (Exh. DTE 6-20). Finally, the Company argues that the SJC has found that an accumulated inefficiencies factor must be supported by substantial evidence of inefficiencies (id.). The Company argues that based on the results of its cost study, Boston Gas is highly efficient company given the business conditions in its service territory (id.). Therefore, an accumulated inefficiencies factor is not warranted (id.).

232 Boston Gas states that, contrary to the Attorney General's assertion, the Company is not requesting a change in the exogenous cost factor. The Company also claims that the Attorney General supports the adoption of the price-cap formula developed by the Department in D.P.U. 96-50 and D.P.U. 96-50-C (Boston Gas Reply Brief at 92, n.47, citing Exh. AG-41, at 30).

233 Boston Gas states that the PEG's models have been reviewed on numerous occasions by the CPUC in PBR proceedings for Southern California Gas, San Diego Gas and Electric (power distribution) and San Diego Gas and Electric (gas distribution). The Company explains that in all cases, the work was subject to extensive review and analysis and the basic data was made available to the CPUC staff (without gathering it into a single comprehensive spreadsheet, as was done for the Attorney General's witness in this case). Also, Boston Gas claims that in all these cases, the CPUC's decision on the industry TFP trend was identical to what PEG had estimated (Boston Gas Brief at 187).

Regarding the Attorney General's argument that the differences between the gas industry and the total business sector do not indicate that gas costs will increase faster than output prices of the business sector, Boston Gas claims that the evidence clearly shows that there are persistent differences in TFP growth between the gas industry and the economy, and that the difference in TFP trends between the two is quite stable (id. at 189, citing Exh. KEDNE/LRK-2; RR-DTE-33).

The Company argues that the Attorney General's criticism of the research design for the productivity and cost studies are without merit for the following reasons (id. at 187-193). First, contrary to the Attorney General's argument, the Northeast sample used in the productivity study did not focus entirely on large distributors serving metropolitan areas, but included also small and medium size distributors serving suburban and even some rural territories (id. at 187-188, citing Exh. KEDNE/LRK-7, at 11). Second, the sample size met the Company's objective of balancing three objectives: comprehensiveness, heterogeneity, and cost (id. at 187-188).[234] Third, Boston Gas' use of a regional definition of the gas distribution industry is consistent with Department precedent (id. at 188-189).[235] Boston Gas asserts that, contrary to the Attorney General's claim that there is no evidence that gas distribution productivity growth is different in the Northeast than in the rest of the country, the Company's

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[234] Boston Gas states that it has demonstrated that increasing the sample size would result in a significant decrease in the cost-benefit ratio (Boston Gas Brief at 188).

[235] Boston Gas contends that there is no requirement for the Company to demonstrate that productivity growth is less for the Northeast than for the nation (Boston Gas Reply Brief at 95-96).

study validates the evidence that the Department used in D.P.U. 96-50 to support a regional definition of the gas distribution industry (id. at 188; Boston Gas Reply Brief at 95-96, citing RR-DTE-124).[236]

Regarding the 1990-2000 sample period used in the productivity study, Boston Gas states that it chose 1990 as the starting date for calculating the TFP trends in order to get the best estimate of the long-run TFP trend for the gas distribution industry. At the time of the study, the year 2000 was the latest year for which productivity indices for the United States economy was available. In addition, Boston Gas states that calculating long-run TFP trends over a ten year period is consistent with industry precedent (Exhs. KEDNE/LRK-2, at 3; AG 7-20; DTE 6-28). Boston Gas explains that the National Bureau of Economic Research ("NBER") dates business cycles beginning with a specific month, while the TFP trends measured by the BLS are only computed annually. Thus, it is difficult to achieve a perfect match between the two periods (Boston Gas Brief at 189). Given the NBER's historical dating of business cycles, the July 1990 through July 2000 sample period is very close to a "peak to peak" business cycle and "about as close to a perfect match as is practical" (id. at 189-190).

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236 Boston Gas states that it discussed other factors that could cause TFP growth to differ between regions in the Company's rebuttal testimony. Furthermore, contrary to the Attorney General's assertion that the factors affecting regional TFP growth do not have regional characteristics, economies of scale do depend on regional economic and output growth. The data presented by the Company showed that economic growth in 1990-2001 was much slower in the Northeast than the nation as a whole and, all else equal, this will lead to less output growth, less economies of scale, and therefore, slower TFP growth (Boston Gas Brief at 189, citing Exh. KEDNE/LRK-7; RR-DTE-124).

The Company refutes the Attorney General's argument that the exclusion of certain variables from the econometric cost model are likely to make the Company appear as an efficient cost performer (id. at 192).[237] First, the Company contends that the Attorney General fails to mention any excluded variable or point to any analysis or evidence supporting the view that the absence of any such variables tends to make Boston Gas' performance better (id.). Second, Boston Gas claims that in addition to its original cost model, the Company produced regression results for 34 alternative models which examined 16 other variables, including five variables suggested by the Attorney General (id., citing Exhs. AG 16-8; AG 9-2; AG 18-1; AG 30-6; AG 30-20; AG 31-8; RR-DTE-123).

With regard to the treatment of taxes in the cost study, Boston Gas states that it produced an alternative cost study that allocated payroll taxes to labor costs rather than capital stocks (id., citing RR-DTE-123). Boston Gas rejects the Attorney General's claim that lower taxes paid by the Company relative to the other distributors in the sample make Boston Gas appear efficient (id. at 193). The Company explains that taxes are a component of capital service price, and that the econometric cost model included an explanatory variable that captures the actual taxes paid by the utility in each year (id. at 193, citing Exh. KEDNE/LRK-2). Furthermore, Boston Gas used each company's actual capital service prices to generate cost predictions that are tailored to the actual taxes paid by each utility (id. at 193). As a result, there is no distortion in the cost predictions produced by the cost study (id.).

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[237] The Company stated that lower consumer dividends are often warranted for the most efficient cost performers (Exh. KEDNE/LRK-1, at 15).

Boston Gas claims that, because the results of all these models are extremely robust and showed the Company to be a superior cost performer, the Attorney General's argument on the effect of taxes should be dismissed (id. at 192-193). The Company asserts that since the Attorney General presented no evidence or credible arguments to the contrary regarding the reasonableness of the econometric estimates and their implication for the X-Factor, the Department should reject the Attorney General's arguments (id. at 193).

Finally, regarding the Attorney General's criticism of the "vintaging" of the 1983 benchmark capital stock, Boston Gas explains that although the inclusion of the Northeast dummy variable in the econometric cost model was not motivated by concerns over the benchmark capital stock, the coefficient on this variable sheds light on the issue of whether the benchmark capital stock was systematically undervalued for Northeast distributors (id. at 190). According to the Company, the fact that the coefficient on the Northeast dummy variable was positive and statistically significant in every instance is "definitive evidence that the Attorney General's hypothesis about the benchmark capital stock is not correct" (id. at 190-191). Therefore, Boston Gas reasons, there is no systematic downward bias in the capital cost measure or the TFP trend (id. at 192).

In conclusion, Boston Gas urges the Department to reject the Attorney General's criticism of the PBR plan (id. at 193). The Company claims that the PBR plan and its supporting studies are reviewable and consistent with Department policies and, therefore, should be approved (id. at 193).

Boston Gas also addresses a number of issues raised by DOER regarding the Company's PBR plan (id. at 178-185). The Company rejects DOER's claim that Boston Gas enjoyed lower costs during the term of the PBR plan under D.P.U. 96-50 because the Company experienced declining TFP over the 1990-2001 period (id. at 178). The Company claims that DOER's analysis is selective, incomplete, and misleading because, while it is true that the Company's TFP declined under D.P.U. 96-50 at a rate of 0.76 percent per annum, the rate of decline was less than the average annual rate of decline of 0.93 percent per annum prior to D.P.U. 96-50 (id. at 178-181, citing RR-DOER-1). Boston Gas attributes the decline in the TFP growth rate to the dramatic decline in output growth under D.P.U. 96-50. Boston Gas claims that the TFP growth could have fallen even more, by an additional negative 1.42 percent, had the Company not cut its input quantity by more than the decline in its output under D.P.U. 96-50 (id. at 179).

Boston Gas also characterizes the conclusions of DOER's labor-input analysis as incomplete and misleading because the analysis does not control for factors like output growth which are beyond management control, but which could affect the Company's cost and TFP performance (id. at 180-181). The Company claims that a close look at its TFP experience before and after PBR supports the conclusion that its performance improved as a result of PBR, but such "before and after" comparisons cannot by themselves isolate the cost impact of PBR. (id. at 181).

The Company claims that DOER's alternative PBR proposal will involve considerable implementation difficulties and make regulation more complex and burdensome (id.

at 181-182). Boston Gas contends that the choice of the PPI-NG as the inflation factor in the price-cap formula is problematic because, among other things, the PPI-NG does not account for output price trends for the total range of services provided by gas distributors. According to the Company, the PPI-NG measures changes in prices for only a single gas distribution service, which is unbundled distribution charges for transportation-only customers (id. at 182-183).[238] Boston Gas, therefore, requests the Department to reject DOER's alternative PBR proposal because they are flawed and without record evidence (id. at 185, 193; Boston Gas Reply Brief at 97).

In summary, Boston Gas claims that the Company's proposed PBR plan is in compliance with the Department's policy directives on PBR, and that the proposal is consistent with Department precedent (Boston Gas Reply Brief at 92). According to Boston Gas, the PBR plan satisfies the Department's standard of review for incentive regulation (id. at 92-95, citing Exh. DTE 6-7). Finally, Boston Gas urges the Department not to abandon the PBR framework in its entirety, as suggested by the Attorney General, because "any decision to eliminate PBR for the Company would not meet the reasoned consistency standard applicable to Department policy initiatives." (id. at 94-95).

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[238] The Company states that PPIs for sales customers are available regionally, but includes gas commodity costs (Boston Gas Brief at 183).

3. Analysis and Findings

a. Introduction

The Department has established that because PBR plans act as alternatives to traditional cost of service regulation, they are subject to the standard of review established by G.L. 164, § 94, which requires rates to be just and reasonable. D.P.U. 96-50 (Phase I) at 242, citing D.P.U. 94-158, at 52-66. A company seeking approval of an incentive proposal is required to demonstrate that its approach is more likely than current regulation to advance the Department's traditional goals of safe, reliable and least-cost energy service and to promote the objectives of economic efficiency, cost control, lower rates, and reduced administrative burden in regulation. Id. at 243.

The proposed PBR framework is consistent with Department precedent. D.P.U. 94-158, at 52-66; D.P.U. 96-50 (Phase I) at 259-339. Further, as discussed below, there is evidence that Boston Gas' operation under its former PBR plan may have contributed to constraining O&M cost growth to some extent, thus benefitting ratepayers (Exh. DTE 6-1). Therefore, rather than rejecting the Company's proposal outright as requested by the Attorney General, the Department proceeds with an examination of the components of the Company's proposal. In the remaining portions of this section, we examine DOER's PBR proposal and the components of the Company's PBR proposal: the price-cap formula; term; earnings sharing mechanism; adjustments for exogenous costs; rate design and pricing flexibility; service quality, and the annual compliance filing.

b. DOER Alternative Price-Cap PBR Proposal

DOER's alternative price-cap PBR proposal is problematic. First, DOER's price-cap PBR proposal was first submitted on brief. There is no record support for DOER's proposal. Further, the PPI-NG inflation index proposed by DOER is more volatile than the GDP-PI, making the use of the PPI-NG in a price-cap formula unappealing. Furthermore, as stated earlier, Boston Gas' use of the GDP-PI as the inflation index in the price-cap formulation is consistent with Department precedent. Therefore, we reject DOER's proposal.

For future reference, if a party to one of our investigations intends to have the Department consider an alternative that departs in a major way from or represents a wholesale revision of a petitioner's proposal, then that party should not wait until briefing to present the alternative. The alternative, if it is to be fairly considered, needs to be broached on the record by that party's witness or through that party's cross examination. Only then can there be informed and intelligent interchange concerning the proposed alternative. Otherwise, the proponent courts dismissal. In so saying, we do not mean suggestions for improvement of or substitute features of a petitioner's proposal, but only what amounts to new proposals never raised until briefing.

c. Price-Cap Formula

The elements of the Company's proposed price-cap formula are the following: an inflation index; and, a productivity offset, which consists of a productivity differential, an input price differential, a consumer dividend, and an exogenous cost factor. We now review these elements, individually.

i. Inflation Index

In D.P.U. 94-50, at 141, the Department found that the GDP-PI is (1) the most accurate and relevant measure of the output price changes for the bundle of goods and services whose TFP growth is measured by the Bureau of Labor Statistics, (2) readily available, (3) more stable than other inflation measures, and (4) maintained on a timely basis. In subsequent proceedings, the Department approved the use of the GDP-PI as the inflation index in the price-cap plans approved for Boston Gas in D.P.U. 96-50 and Berkshire Gas Company in D.T.E. 01-56. Those same merits are of value here, too. Therefore, consistent with Department precedent, we approve the use of the GDP-PI as the inflation index in the Company's price-cap formula.

In D.P.U. 96-50 (Phase I) at 262, 273, the Department directed that the inflation index be calculated as the percentage change between the average for the current year's and prior year's four quarterly measures of the GDP-PI as of the second quarter of the year. Therefore, consistent with Department precedent, we find that Boston Gas shall calculate its inflation index as the percentage change between the average for the current year's and prior year's four quarterly measures of the GDP-PI as of the second quarter of the year.

ii. Productivity Offset

(A) Introduction

The elements of the Company's proposed productivity offset consists of four components. These components are (1) a productivity growth index, which is intended to include the average annual growth in productivity, during a specified time period, for the

companies that constitute a regulated industry, (2) an input price growth index, which is intended to include the average annual growth in input prices, during a specified time period, for the companies that comprise a regulated industry, and (3) a consumer dividend factor, which is intended to include expected future gains in productivity for a company that has moved away from cost-of-service ratemaking to performance-based ratemaking. See, e.g., D.P.U. 94-50, at 160-168; D.P.U. at 96-50 (Phase I) at 262-279.

(B) Productivity and Input Price Growth Indices

The productivity and input price growth indices are intended to reflect the average annual growth in productivity and input prices, during a specified time period, for the companies that comprise a regulated industry. Considered jointly, these indices should determine the average annual increase in per-unit costs, during a specified period, for the regulated companies.[239] For a particular company, the indices serve as proxies for the growth in per-unit costs that the company should have experienced during the specified period, if it were an average-performing company. A company that achieved lower-than-average growth in per-unit costs during this period would be rewarded under a price-cap regulation, i.e., it would have the opportunity to earn additional profits. Conversely, a company whose growth in per-unit costs exceeded the average might realize lower-than-anticipated profits.

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[239] For companies operating in a competitive market, the trend in per unit costs should be equal to the trend in output prices. Therefore, the difference between an industry's per unit costs and per unit costs of the United States economy should be equal to the difference between the industry's output prices and price inflation for the overall economy. D.P.U. 96-50 (Phase I) at 274, n.122.

In the instant proceeding, the Department must decide whether the historic productivity and input price growth indexes for Boston Gas should be based on regional or nationwide LDCs indices. Next, the Department must decide whether the values of the productivity and input price growth indices proposed by Boston Gas are reasonable.

In D.P.U. 96-50 (Phase I) at 275-276, the Department found that the use of productivity growth for regional LDCs, i.e., Northeast LDCs, was appropriate for Boston. In the instant proceeding, the Company presented additional evidence which supports the use of a regional definition of the gas distribution industry for Boston Gas (RR-DTE-124; Exh. KEDNE/LRK-3).[240] The Company's evidence is consistent with and, in fact, improves upon what was found substantial and sufficient in our recent precedent. Therefore, consistent with that precedent, the Department finds that Boston Gas' use of a regional, i.e., Northeast, definition of the gas distribution industry is appropriate.

Regarding the Attorney General's assertion that Boston Gas did not use a representative sample for the productivity study, we find that the Company offered a reasonable explanation for limiting the study to the 16 companies included in the Northeast sample. The record shows that there is no standardized database for gas utilities that can be used to construct a TFP index for the gas distribution industry (Exh. AG 7-13). Boston Gas selected a sample that, given data limitations, balanced the objectives of comprehensiveness, heterogeneity, and cost. The

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240 For example, in terms of economic growth, the Company showed that, for the period 1990 through 2001, only one of the nine Northeastern states ranked in the top 15 fastest-growing states (New Hampshire), while six of the remaining eight northeastern states ranked among the 15 slowest-growing states in the nation (RR-DTE-124).

Company achieved a sample coverage of 31 percent of the gas distribution companies in the Northeast, which we find reasonable (Exhs. KEDNE/LRK-2, at 10; AG 12-7; Tr. 19, at 2492).[241] Therefore, the Department finds that the claimed "non-representativeness" of the sample, as the Attorney General asserts, is not sustainable; and we doubt that information on 100 percent of regional companies would significantly change the results of the productivity study (Tr. 19, at 2496). In addition, we find that the errors in the data used by Boston Gas in the productivity study did not affect the results of the 1990-2000 productivity study because the errors were in the 1999 and 2001 cost data. The productivity and input price trends for the Northeast gas distribution industry were calculated using data for the years 1990 and 2000 (Exh. AG 31-11; Tr. 10, at 1178-1182). With respect to the Attorney General's argument that the measure of output used in the productivity study does not reflect the introduction of new products and the improvement in service quality, the Department finds that the measure of output used by the Company, which includes the number of customers and throughput, is consistent with Department precedent. D.P.U. 96-50 (Phase I) at 275-276.

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[241] This calculation is based on the gas utility as the unit of analysis. Boston Gas included 16 companies out of a total of 52 companies in the northeast sample for the productivity study, yielding a 31 percent sample coverage. The 52 companies include the 16 companies listed in Exhibit KEDNE/LRK-2, at 10; the 34 companies listed in Exhibit AG-12-7; and Essex and Colonial, which the Company should have included in Exhibit AG-12-7 (Tr.11, at 1321). The 16 companies included in the sample serve about 60 percent of the gas end-users in the Northeast (Exh. KEDNE/LRK-2, at 10). So, 31 percent of the region's companies and 60 percent of gas end-users must be regarded as a sampling so substantial that it withstands mere assertion of inadequacy, without more. It meets the substantial evidence test by any reasonable view of that test.

The Department is not persuaded by Boston Gas' explanation that one of the reasons it selected the 1990-2000 period for the productivity study is that it wanted the period to correspond to the same peak-to-peak points in the business cycle. The explanation is inconsistent with the design of the 1984-1994 productivity study in D.P.U. 96-50, which did not correspond to the same peak-to-peak points in the business cycle (Tr. 11, at 1286-1287). Boston Gas presented the 1984-1994 study in support of its PBR proposal in that proceeding, which the Department approved. Therefore, we reject limiting our view to the 1990-2000 period used by the Company for the productivity study. It is Department policy to rely on the most recent information available. Bay State Gas Company, D.T.E. 01-81-A at 6 (2003); Western Massachusetts Electric Company, D.P.U. 95-8-CC (Phase II) at 31, 43 (1995). Here, the record justifies the use of the 1990-2001 period for the productivity study because 2001 is the closest year to the test year for which data are available. Moreover, the Company testified that there was nothing wrong with the 2001 data (when they became available), and that they could be included in the TFP study (Tr. 11, at 1286-1288). Also, the use of a time period of 11 years to estimate long-run productivity trends is consistent with industry precedent and with capturing as much as we can the recent economic downturn that began in early 2000 (Exh. DTE 6-28).

Boston Gas updated the productivity study to include the period 1990-2001 (Exh. AG-9-1 Supp.). The results of the updated productivity study determined that TFP for the Northeast gas distribution industry grew at an average annual rate of 0.60 percent over the

1990-2001 period.[242] The average annual growth in the MFP index for the United States economy was 0.77 percent over the same period. The productivity differential for the 1990-2001 period was negative 0.17 percent, i.e., 0.60 percent minus 0.77 percent.[243]

The Department agrees with the Attorney General that there are problems with the estimation of the cost of capital in both the productivity and cost studies.[244] The Attorney General has correctly argued that the inclusion of payroll taxes in the estimation of the cost of

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242 The evidence shows that the error in the 2001 cost data which the Attorney General alluded to had a negligible effect on the TFP trend for the Northeast gas distribution industry for the period 1990-2001 (Exh. AG 31-11). The updated productivity study allocated payroll taxes to capital costs rather than to labor costs which we discuss below (Exh. AG 9-1 [supp.]).

243 Boston Gas stated that three factors were responsible for the dramatic change in the productivity differential with the inclusion of 2001 data. First, the Bureau of Labor Statistics revised the United States MFP growth downward for the 1990-2000 period from 0.98 percent to 0.95 percent. Second, the MFP for the United States economy fell by 1.1 percent in 2001. This decline reduced the economy's average annual productivity growth from 0.95 percent to 0.77 percent, which raised the TFP differential by 0.18 percent. Finally, the TFP trend for the gas distribution industry rose from 0.53 percent over the 1990-2000 period to 0.60 percent for the 1990-2001 period. Compared to 2000, the industry's output declined, but input quantities declined even more. The updated industry TFP trend raised the TFP differential by 0.07 percent (Exh. AG 9-1 [Supp.]).

244 We address the other concerns expressed by the Attorney General regarding the estimation of the cost of capital in Section V.A.3, above.

capital is problematic.[245] Boston Gas further updated the productivity study for the period 1990-2001 to reallocate payroll taxes from capital costs to labor costs (RR-DTE-123).[246] The results of the new updated productivity study (which reallocated payroll taxes from capital costs to labor costs) determined that the average annual growth rate for the output quantity and the input quantity indexes for the Northeast gas distribution industry for the 1990-2001 period were 1.27 percent and 0.69 percent, respectively. The TFP growth rate for the Northeast gas distribution industry was 0.58 percent over the 1990-2001 period.[247] In comparison, the average annual growth in the MFP index for the United States economy was 0.77 percent over the same period (Exh. AG 9-1 [supp.]). The resulting productivity differential between the Northeast gas distribution industry and the United States economy for the 1990-2001 period (with payroll taxes reallocated from capital costs to labor costs) was negative 0.19 percent.[248] The input price differential between the United States economy and the Northeast gas distribution industry in the original updated 1990-2001 study is equal to 0.3 percent (id.).[249]

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245 The Company acknowledged that PEG "has allocated payroll taxes to labor costs rather than capital costs in the past" (RR-DTE-123, at 1). This corrects the Company's earlier testimony regarding the treatment of payroll taxes (Tr. 26, at 3577-3583).

246 Boston Gas did not update the 1990-2000 productivity study to reallocate payroll taxes from capital costs to labor costs (RR-DTE-123).

247 The TFP growth rate for the Northeast gas distribution industry was calculated as (1.27 - 0.69) = 0.58 percent.

248 The productivity differential was calculated as (0.58 - 0.77) = negative 0.19 percent.

249 Boston Gas stated that the input price differential widened when the study was updated to 2001 because input prices fell for the gas distribution industry in 2001 as a result of lower interest rates and returns to capital in 2001 compared to the previous year

(continued…)

Therefore, the Department finds that a productivity growth index and an input price growth index in the price-cap formula equal to negative 0.19 percent and 0.3 percent, respectively, are appropriate.

(C) Consumer Dividend

The Department stated its rationale for including a consumer dividend factor in the productivity offset of a price-cap formula in D.P.U. 94-50, at 165-166. The consumer dividend factor serves as a "future" productivity factor because it is intended to reflect expected future gains in productivity due to the move from cost-of-service regulation to performance-based regulation. In the instant proceeding, Boston Gas has proposed a 0.15 percent consumer dividend. Boston Gas has argued that the 0.15 percent consumer dividend is based on the results of the cost study and on the Company's judgment as to the appropriate level of the consumer dividend during the term of the PBR plan.[250] Predicting the "expected future gains in productivity" for Boston Gas is difficult because of uncertainty about economic conditions in the future. As a starting point, in order to determine whether the consumer dividend proposed by Boston Gas is reasonable, the Department will evaluate the

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249 (…continued)
(Exh. AG 9-1 [supp.]). Boston Gas did not calculate an input price differential in the new updated productivity study which reallocated payroll taxes from capital costs to labor costs (RR-DTE-123).

250 The Department finds that the Company's testimony regarding the setting of the consumer dividend is not inconsistent as DOER claims. Boston Gas used the results of the cost study as a guide in setting the consumer dividend. However, the actual consumer dividend of 0.15 percent proposed by Boston Gas was based on the Company's judgment as to the appropriate level of the consumer dividend going forward (Exhs. AG 7-11; AG 11-54; DTE 6-8).

Company's performance under the first PBR plan. Next, the Department will assess what the evidence tells us about the Company's potential for achieving additional productivity and efficiency gains during the term of the proposed PBR plan.

The evidence shows that Boston Gas achieved some efficiency gains in terms of lower O&M cost growth during the term of the first PBR plan. The Company's O&M expenses (in real 1990 dollars) increased at a much slower rate of 0.6 percent per annum, on average, between 1996-2002, compared to a 1.9 percent average annual growth rate between 1990-1996, i.e., the pre-PBR period. In terms of annual dollar increases (in real 1990 dollars), Boston Gas' O&M expenses increased by $1.29 million per year, on average, between 1996-2002, compared to a $2.48 million increase per year, on average, between 1990-1996. The Company's distribution revenues followed the same trend as O&M expenses. Between 1996-2002, distribution revenues (in real 1990 dollars) increased at an average annual rate of 0.2 percent, compared to a 4.5 percent increase per year, on average, between 1990-1996. In terms of annual dollar increases (in real 1990 dollars), Boston Gas' distribution revenues increased by $2.51 million per year, on average, between 1996-2002, compared to a $4.98 million increase per year, on average, between 1990-1996 (RR-DTE-48; Exh. DTE 6-1). We note that 1996 was the year the PBR plan was instituted, and we infer cause, not mere coincidence, as the basis for the change in revenues. Regarding DOER's claim that Boston Gas' labor costs actually increased during the term of the first PBR plan, the record

shows rather different: viz., that the Company's (arithmetic) average labor quantity index was lower during PBR (0.860) than before PBR (0.913) (RR-DOER-1).[251]

The evidence shows that Boston Gas did not achieve any significant gains in productivity during the term of the first PBR plan, compared to the period before PBR (id.). A comparison of Boston Gas' (arithmetic) average TFP index before and during PBR reveals that, relative to the 1990 TFP index of 1.000, the average TFP index before PBR was higher than the average TFP index during PBR, i.e., 0.937 compared to 0.914, respectively (id.). In terms of productivity growth rate, Boston Gas' TFP index grew at an average annual rate of 0.12 percent from 1992 to 1996, compared to an average annual growth rate of negative 0.90 percent from 1997 to 2001.[252] Therefore, the Department rejects the Company's claim that it achieved improvements in productivity under PBR so as to warrant a consumer dividend lower than 0.15 percent.

Boston Gas claims that it based the 0.15 percent consumer dividend partly on the results of the cost study. The results of the cost study determined that, during the 1993-2000 period, the Company's average cost was about 27 percent below its predicted value, and that the independent effect of the PBR plan on costs was a 0.3 percent decline in costs during the term of the PBR plan. According to Boston Gas, the Company's actual costs would have been

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251 For a better comparison, the Department defines the period before PBR as 1992-1996, and the period during PBR as 1997-2001, so that each period is five years.

252 The Department disagrees with Boston Gas that the Company has no control over output growth. Boston Gas' actions and programs could lead to new customers for the Company, or to existing customers leaving Boston Gas' system in favor of other energy sources. See D.P.U. 96-50 (Phase I) at 338.

0.3 percent higher in 1997, 1998, 1999, and 2000, had the Company not been under a PBR plan. This translates into total cost savings attributed to the independent effect of the PBR plan of $4.065 million (Exh. DTE 6-51).

The Department finds that the models used in the productivity and cost studies are not so complex that they are not reviewable. We also find that the cost study followed standard econometric practice in selecting variables that were included in the econometric cost model (Exh. AG 12-17). We accept, as reasonable, the Company's explanation that, as a practical matter, it is difficult to achieve "a perfect correspondence between the Handy-Whitman Index and the [USR] data that exits, and because of that, it's not possible to perfectly tailor the Handy-Whitman Index to the capital [type categories]" (Tr. 26, at 3584-3586). Also, the Department finds that Boston Gas measured the four components of capital cost in the cost study to include taxes, the opportunity cost of capital (or the cost of funds), depreciation, and capital gains (Exhs. KEDNE/LRK-2, at 19-20; KEDNE/LRK-3, at 19). The Company calculated taxes as the sum of total tax payments and franchise fees attributed to the LDC. Therefore, the record shows that the inclusion of actual taxes with costs is consistent with the theoretical model that Boston Gas used for the cost study (see RR-DTE-126).

As we discussed earlier, we agree with the Attorney General that Boston Gas' estimation of the cost of capital is problematic. Regarding the "vintaging" of the 1983 benchmark capital stock, we are not persuaded by the Company's explanation that this is not a problem because "the coefficient [on the Northeast dummy variable] in the econometric cost model "sheds light on the issue of whether the benchmark capital stock was systematically

undervalued for Northeast distributors." The Attorney General correctly argues that "if utilities in the Northeast were uniformly older than utilities in the rest of the country, the cost understatement for older plants would have a negative effect, but not necessarily produce a negative coefficient for the Northeast dummy variable." Therefore, we find that the positive coefficient on the Northeast dummy variable is not sufficient proof that the study has not understated costs for Northeast plants, which on average, are older than plants in other regions of the country. To demonstrate that there was no systematic bias in the capital cost measure due to age differences in utility plants across the country in 1983, Boston Gas should have shown that the difference in the average age of plants in the Northeast and the average age of plants in the rest of the country in 1983 was not statistically significant.

Capital is the major input for gas distributors (Exh. DTE 6-31). Therefore, problems with the measurement of the cost of capital are likely to distort the results of Boston Gas' cost study.[253] In the instant case, the Department finds that it is likely that Boston Gas overestimated the Company's cost savings during the 1993-2000 period, including the 0.3 percent cost decline that it attributed to the independent effect of the first PBR plan, because of the way the cost study estimated the cost of capital. Other problems with the cost study include the study's underlying assumptions and errors in the cost data which Boston Gas used.

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[253] This is particularly true given that Boston Gas' capital service price was about nine percent above the sample mean (Exh. KEDNE/LRK-3, at 12).

The cost study assumed that prices for "other inputs" were the same for all companies in the sample. According to the Company, "[t]his simplifying assumption may well distort results for Boston Gas. After all, it is quite possible that a region with high labor and construction costs also has higher average prices for other production units, especially those that are intensive in the use of local labor." (Exh. KEDNE/LRK-3, at 12). In addition, the cost study did not distinguish between distribution and non-distribution labor and O& M expenses, but assumed that all costs were distribution costs (Tr. 10, at 1183).[254] Regarding errors in the cost data, Boston Gas testified that errors in the cost data could distort the results of the study because "every data point is going to determine the estimated coefficients. [Every data point] is going to have an impact on the estimated coefficients" (Exh. AG-31-11; Tr. 10, at 1178-1182). Finally, the Company testified that it was likely that the cost study overestimated Boston Gas' cost performance by not controlling for the Essex and Colonial merger-related savings (Tr. 11, at 1340-1342).[255]

As the Attorney General has argued, the above evidence shows that the results of the cost study are distorted. Therefore, the Department rejects the Company's claim that Boston Gas is a superior cost performer, and that the independent effect of the first PBR plan was a 0.3 percent cost savings which the Company achieved under D.P.U. 96-50. Rather, we find

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[254] Boston Gas stated that these data are generally not available (Tr. 10, at 1183).

[255] Boston Gas updated the cost study to reallocate payroll taxes from capital costs to labor costs. The results determined that the difference between the Company's actual and predicted costs was approximately negative 23 percent, and statistically significant. The original cost study, therefore, overestimated Boston Gas' cost savings by approximately 4 percentage points (RR-DTE-123).

that (1) Boston Gas overstated its cost efficiency, (2) the 0.3 percent cost savings which the Company attributed to the PBR plan is the minimum cost savings that Boston Gas achieved as a result of the independent effect of the PBR plan, and (3) there is the potential for Boston Gas to achieve additional cost savings and productivity gains in the future.

The evidence suggests that there is the potential for Boston Gas to achieve further cost savings and become more efficient during the term of the PBR plan. Boston Gas' capital and labor costs are nine percent and 13 percent higher than the industry average. PBR should provide the Company with the incentive to bring its capital and labor costs closer to the industry average. In addition, Boston Gas has stated that it has a policy to tie employee compensation at the "business unit level" to specific cost-reduction initiatives or activities (RR-DTE-49; Exh. KEDNE/JCO-14; Tr. 18, at 2464-2466). This link should result in further efficiency gains for the Company under the proposed PBR plan. The Company has also stated that it has instituted a two-year cost reduction plan whose goal is to achieve synergies resulting from the merger of its parent Keyspan with its former parent Eastern Enterprises (RR-DTE-49). The synergies resulting from the merger of Keyspan and Eastern Enterprises should result in additional cost savings for Boston Gas (id.). Finally, Keyspan's business transformation initiative should result in additional productivity gains for Boston Gas (id.).

The Attorney General has proposed that the consumer dividend for Boston Gas should be at least one percent. The Attorney General did not provide any empirical basis for his proposal. We agree with the Attorney General that a higher consumer dividend will result in

greater benefit for customers, and a greater incentive for Boston Gas to achieve further cost reductions and productivity gains under the PBR plan. However, these concerns must be balanced against the potential for Boston Gas to achieve cost reduction and productivity gains going forward, and the need to allow the Company to earn sufficient revenue so that it can provide reliable service to customers. In short, the Department's decision is constrained by the requirement of substantial evidence and thus must be tethered to the record. The Department, therefore, rejects the Attorney General's tempting but unsupported proposal. We also reject Boston Gas' proposal of a 0.15 percent consumer dividend because (1) the Company overstated the cost savings that it achieved under the first PBR plan, (2) Boston Gas did not demonstrate that it achieved improvements in productivity during the term of the first PBR plan, and (3) there is the potential for Boston Gas to achieve significant cost saving and productivity gains going forward. The Company estimated cost saving of 0.3 percent attributable solely to the PBR plan. The Department finds that the 0.3 percent cost saving is the minimum cost saving that Boston Gas achieved solely as a result of the PBR plan. Based on the evidence before us, the Department expects that Boston Gas will achieve cost savings and productivity gains significantly greater than the 0.3 percent minimum cost savings that the Company attributed to the independent effect of the first PBR plan. Therefore, the Department finds that a consumer dividend factor equal to 0.3 percent in the price-cap formula is reasonable and warranted in the record before us.[256]

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[256] The Department approved a consumer dividend of 0.5 percent for Boston Gas in D.P.U. 96-50, and a consumer dividend of 1.0 percent for Berkshire in D.T.E. 01-56.

(continued…)

(D) Summary of the Productivity Offset

Based on the findings stated above, the Department directs the Company to recalculate the productivity offset in the price-cap formula in the following manner. First, the Company is directed to use a value of 0.3 percent for the input price growth index. Second, the Company shall use a value of negative 0.19 percent for the productivity growth index. Third, the Company is directed to include a consumer dividend factor equal to 0.3 percent. This results in an overall productivity offset equal to 0.41 percent.[257] The productivity offset shall remain constant throughout the term of the PBR plan. As discussed earlier in Section IV.BB.3, the Department has directed Boston Gas to remove completely from base rate any amounts included in Company's pension/PBOP reconciliation adjustment mechanism. Therefore, the Department directs that the price-cap formula shall not be applied to the proposed pension/PBOP reconciliation adjustment mechanism.

iii. Exogneous Cost

(A) Introduction

The Company proposes to maintain the exogenous cost factor established in D.P.U. 96-50 (Exh. KEDNE-JFB-1, at 26). Boston Gas proposes to recover (or return) exogenous costs, defined as (1) changes in tax laws, accounting principles, and regulatory,

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256 (…continued)
See D.P.U. 96-50-C at 58; D.T.E. 01-56, at 21.

257 The Department approved a productivity offset of 0.5 percent for Boston Gas in D.P.U. 96-50, and a productivity offset of one percent for Berkshire in D.T.E. 01-56. See D.P.U. 96-50-C at 58; D.T.E. 01-56, at 21.

judicial, or legislative actions uniquely affecting the local gas distribution industry, and (2) cost changes that are beyond the Company's control and not accounted for in the GDP-PI term used in the Company's PBR formula (id.). Under the Company's proposal, individual exogenous costs will have to exceed a $500,000 threshold in a particular year in order for the Company to request recovery (id.).

(B) Positions of the Parties

(1) Attorney General

The Attorney General contends that any PBR plan should have an appropriate exogenous cost factor that accounts for cost reductions as well as cost increases (Attorney General Brief at 114, citing RR-DTE-74). However, the Attorney General opposes the Company's proposed new "formulaic capital replacement provision" for exogenous costs (id. at 114). The Attorney General argues that the Company has testified that cast iron replacement could qualify as an exogenous cost (RR-DTE-74). Instead, the Attorney General supports the use of an exogenous cost factor consistent with those approved in the recent Berkshire and Colonial PBR plans (Attorney General Brief at 114, citing RR-DTE-74).

(2) DOER

DOER contends that the Company's proposed definition of exogenous costs is ambiguous because it includes an additional provision designed to capture other, non-specific factors (DOER Brief at 29). DOER argues that the Department should limit the exogenous factor to precisely what was approved in D.P.U. 96-50 (id.). DOER also argues that the

threshold for exogenous costs should be proportional to the Company's operating revenues, rather than set at a $500,000 per event threshold, as proposed by the Company (id.).

(3) Boston Gas

The Company argues that its proposed definition of exogenous costs is no different than that approved by the Department in D.P.U. 96-50 (Phase I) at 292 (Boston Gas Reply Brief at 92). The Company maintains that it is not requesting a change in the exogenous cost factor (id., n.47).

iv. Analysis and Findings

The Department has now reviewed definitions of exogenous costs in several ratemaking contexts. D.P.U. 96-50 (Phase I) at 292; D.T.E. 98-31, at 17;D.T.E. 98-27, at 19; D.T.E. 98-128, at 54-55; D.T.E. 01-56, at 25. In these cases, the Department has affirmed that the definition of exogenous costs contained within D.P.U. 96-50 defines the types of events that constitute legitimate costs that the Company cannot anticipate prior to entering into long-term PBR plans. Exogenous costs are defined in D.P.U. 96-50 (Phase I) at 292 as follows:

> [E]xogenous costs shall be defined as positive or negative cost changes actually beyond the Company's control and not reflected in the GDP-PI, including but not limited to cost changes resulting from:
>
> - changes in tax laws that uniquely affect the local gas distribution industry;
> - accounting changes unique to the local gas distribution industry; and
> - regulatory, judicial, or legislative changes uniquely affecting the local gas distribution industry.

> [P]roponents of exogenous cost recovery will bear the burden of demonstrating that the cost were beyond the company's cost control, and (2) not reflected in the GDP-PI.

The Company contends that its proposed definition of exogenous costs is no different than that approved by the Department in D.P.U. 96-50 (Exh. KEDNE/JFB-1, at 26; Boston Gas Reply Brief at 92, n.47). However, both the Attorney General and DOER raise concerns that Boston Gas is requesting an expanded definition of exogenous costs (Attorney General Brief at 114, citing RR-DTE-74; DOER Brief at 29).[258] In the instant proceeding, the Department approves the same definition of exogenous costs as approved in D.P.U. 96-50, at 292. See also D.T.E. 01-56, at 25. That should resolve any perceived ambiguity on the instant record.

With respect to the exogenous cost threshold, Boston Gas proposes that the Department maintain the $500,000 level approved in D.P.U. 96-50 (Phase I) at 293 (Exh. KEDNE/JFB-1, at 26). However, in D.P.U. 98-128, at 53-54 and D.T.E. 01-56, at 22-26, the Department established the method by which the threshold level for the recovery of exogenous costs must be set. We determined that the exogenous cost threshold must be the result of multiplying a company's operating revenues by a factor of .001253.[259] D.T.E. 01-56, at 22-26. Applying this factor to Boston Gas' 2002 operating revenues of $639,110,583 results in an amount

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[258] In the prefiled testimony of Lawrence Kaufmann, PhD, the Company includes mandated replacement of cast iron and bare steel main as a possible exogenous cost (Exh. KEDNE/LRK-1, at 3).

[259] This factor is the ratio of Colonial's exogenous cost threshold to its operating revenues. D.T.E. 98-128, at 53-54; D.T.E. 01-56, at 22-26.

slightly over $800,000 (Exh. AG-1-2b(8)(a)). Therefore, Boston Gas' threshold for exogenous cost recovery under this method would be $800,000 for each individual event. We find that this is a reasonable amount for a company with operating revenues of $639,110,583 that is implementing a multi-year PBR plan. Accordingly, we set the threshold for exogenous cost recovery at $800,000 for each individual event.

C. Term of the Plan

1. Boston Gas Proposal

The Company proposes to establish the PBR plan on November 1, 2003, coincident with the effective date of the cast-off rates resulting from the rate case (Exh.KEDNE/JFB-1, at 27). The initial term of the PBR plan would be five years (id.). The Company would file five annual compliance filings establishing rates to take effect on November 1 of each year. (id.). The first PBR rate adjustment would take place on November 1, 2004 and the last PBR rate adjustment would take place on November 1, 2008 (id.; Tr. 13, at 1647).

Under the Company's proposal, the PBR plan could be extended beyond the initial term of the plan on a year-to-year basis, without further action required by the Department (Exh. KEDNE/JFB-1, at 27).[260] Commencing June 1, 2009, and annually thereafter, the Company would notify the Department of its intention to submit a compliance filing each September 15 to extend the term of the PBR plan by an additional year ("June 1 Filing") (id.). The

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[260] Under the Company's proposal, the Department could initiate an investigation on its own motion, or at the request of the Company under G.L. c. 164, § 94, or the Attorney General or other entitled persons under G.L. c. 164, § 93 (Exh. DTE 6-11).

Company has not proposed a limitation on the number of years that it could renew the plan (Tr. 13, at 1648).

2. Positions of the Parties

a. Attorney General

The Attorney General does not directly address the term of the PBR plan. The Attorney General instead advocates rejection of the entire plan (Attorney General Brief at 107; Attorney General Reply Brief at 54, 62).

b. DOER

DOER states that under Boston Gas' proposed PBR plan, the Company possesses "unfettered and exclusive control" over the length of the PBR plan (DOER Brief at 32). DOER recommends that the Department approve a PBR plan that has an initial five-year term, after which the Department would initiate a review and determine whether continuing the PBR plan would ensure just and reasonable rates (id.). Any further term would be subject to the Department's review, in conjunction with an opportunity for all interested parties to intervene and participate (id.).

c. Bay State

Bay State Gas contends that the five-year term proposed by Boston Gas supports the employment of carefully designed incentive rates to continue inducing efficiencies during the term of the plan (Bay State Brief at 4). Bay State Gas also contends that a ten-year term for the PBR plan would be inappropriate and would not serve to benefit ratepayers, even if returns were adjusted to reflect additional risk (id. at 5). Additionally, Bay State argues that a ten-year

term would alter substantive rights retained by the Company by statute, in particular the right to file for a rate case if rates are not just and reasonable (id.). For these reasons, Bay State Gas maintains that the five-year term for Keyspan is reasonable (id.).

d. Boston Gas

The Company contends that the five-year term of the plan strikes a balance between creating incentives and accounting for recent trends within the gas industry concerning price and growth (Boston Gas Brief at 162). The Company argues that if the time between plan review is too long, there is a possibility that the data used to set the terms of the plan will become "stale" and no longer reflect current conditions (id.). The Company's PBR plan, therefore, is designed to be long enough to create meaningful incentives, but short enough to reflect current circumstances within the gas marketplace (id.).

3. Analysis and Findings

The Department has stated that one potential benefit of incentive regulation is a reduction in regulatory and administrative costs. D.P.U. 94-158, at 64; D.P.U. 01-56, at 10. Additionally, the Department has found that a well-designed PBR plan should be of sufficient duration to give the plan enough time to achieve its goal and to provide utilities with the appropriate economic incentives and certainty to follow through with medium and long-term strategic business decisions. D.P.U. 94-158, at 66; D.P.U. 96-50 (Phase I) at 320; D.T.E. 01-56, at 10.

As discussed earlier, Boston did not achieve significant cost savings and productivity gains during the term of the first PBR plan. The record also shows that Boston Gas' costs for

the test year 2002 were higher than 2001 (Tr. 18, at 2352-2355). The Company's testimony provided an explanation: the short duration of the PBR plan made it difficult for the Company to achieve significant cost savings (Tr. 11, at 1300-1301). Specifically, the Company testified that shorter-term PBR plans create weaker incentives (to companies) and provide fewer benefits to customers (id.). The Company also testified that setting the term of the PBR plan at ten years provides a stronger incentive to achieve efficiencies (Tr. 10, at 1246; Tr. 11, at 1301-1302, 1353-1354, 1416). According to the Company, a stable, long-term operating environment (ten-year term) could promote longer-term cost reduction and marketing initiatives and stronger performance incentives (Exh. DTE-6-11).

The Company's PBR annual renewal proposal does not remedy the problems with the suggested five-year term. In fact, this proposal mandates that, from the fifth year of the PBR plan onward, the Company would operate, in effect, under a one-year planning horizon and would prevent the Company from receiving the appropriate economic incentives and certainty to follow through with medium and long-term strategic business decisions. The Company attempted to implement this type of mechanism at the end of the term of the PBR plan in D.P.U. 96-50 (Phase I) and we rejected it. D.T.E. 02-37.

The Department finds that the five-year term proposed by Boston Gas is not long enough to achieve the efficiencies and benefits that a PBR plan is expected to provide to shareholders and ratepayers. Therefore, we reject the five-year term (with "evergreen" renewal) proposed by Boston Gas. Rather, the Department finds that a term of ten years is reasonable for Boston Gas to implement long-term business strategies that could produce

significant cost savings and other benefits to ratepayers and shareholders. In addition, a ten-year PBR plan will reduce the regulatory burden of implementation. Finally, a ten-year PBR plan is consistent with current Department policy on performance-based rate making. See D.T.E. 01-56, at 10. In D.T.E. 01-56, at 10, the Department found that a ten-year term was appropriate. There, the Department stated that a ten-year plan "provided a sufficient period to evaluate administrative efficiencies and to allow Berkshire the level of certainty required to enter into business decision-making." Id.

In the present case, Boston Gas argues that a longer-term PBR exposes the Company to greater risk because of the uncertainty about long-term economic conditions. However, the exogenous cost factor and the earnings sharing mechanism incorporated into the PBR plan will mitigate risks that shareholders and ratepayers may face as a result of a ten-year PBR plan.[261]

The Department rejects Bay State's argument that a ten-year term for the PBR plan would not serve to benefit ratepayers, even if adjustments are made to account for the additional risks associated with a long-term PBR plan. First, Bay State has not provided any empirical evidence to support its argument. Second, a ten-year PBR plan would not alter substantive rights retained by Boston Gas by statue to file a rate case if rates are not just and reasonable. Department actions cannot abrogate statutory rights in rate setting. D.T.E. 98-27, at 14-21.

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[261] Additionally, the Company has initiated a significant "enterprise wide" business transformation initiative to cut costs (Tr. 22, at 2975).

DOER suggested that the Department initiate a review, after the fifth year of the proposed plan.[262] Since the Department has extended to ten years the term of the PBR plan, the Department finds that a mid-period review may be appropriate and reserves the option of initiating such a review sua sponte. With regard to Bay State Gas' contention that a ten-year PBR plan cannot be approved by the Department since it limits the right of the Company to apply for rate relief, the Department considers a mid-period review an appropriate forum for determining if the plan should continue, be modified, or be terminated.[263] This review, if initiated by the Department, would provide the Company and other interested parties an opportunity to determine if the PBR plan should be continued or terminated.

D. Earnings Sharing Mechanism

1. Boston Gas Proposal

The Company proposes to maintain the earnings sharing mechanism approved by the Department in D.P.U. 96-50 (Phase I) (Exh. KEDNE/JFB-1, at 26). Under this structure, a bandwidth of 400 basis points would be established around the Company's authorized return on

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262 The mid-period review would occur in April, 2008.

263 Moreover, the Department has found that extraordinary economic circumstances have always been a recognized basis for any gas or electric company to petition the Department for changes in tariffed rates. D.T.E. 98-31, at 18; D.T.E. 98-128, at 56. This review is consistent with G.L. c. 164, §§ 93 and 94 and with the general requirement that rates must be just and reasonable. Statute, of course, governs and, where need be, supercedes any regulatory arrangement prescribed by the Department. D.T.E. 98-27, at 14-21. This view is not inconsistent with the safety valve provisions in the Company's testimony (Exh. KEDNE/JFB-1, at 27).

common equity (id.).[264] If the Company's actual return on common equity was 400 basis points below the Company's authorized return on common equity, 75 percent of the loss would be borne by shareholders and 25 percent of the loss would be borne by ratepayers (id.). If the Company's rate of return exceeds its authorized ROE by 400 basis points, then 75 percent of the gain will inure to shareholders and 25 percent to ratepayers (id.).

2. Positions of the Parties

a. Attorney General

The Attorney General supports the implementation of an earnings sharing mechanism (Exh. AG-41, at 2; Attorney General Brief at 114). The Attorney General contends that the earnings sharing mechanism should only be on excess earnings, not earnings below the authorized rate of return as proposed by the Company (RR-DTE-72; Attorney General Brief at 114). The Attorney General proposes a sliding two-tiered earnings sharing mechanism (RR-DTE-72). If the Department were to set the consumer dividend at one percent, the Attorney General's recommended plan would call for a sharing of earnings of 50/50 for over earnings of 200-400 basis points above the Company's regulated rate of return (id.). If earnings exceeded the set rate of return by more than 400 basis points, ratepayers would receive 75 percent of the earnings (id.). The Attorney General's proposed earnings sharing mechanism would lower the above deadbands if the consumer dividend was set at less than one percent and would widen the deadbands if the consumer dividend was set at a rate above one

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[264] The Company has proposed a return on equity of 12.18 percent (Exh. KEDNE/JFB-1, at 26).

percent (id.). The Attorney General recommends that no earnings sharing occur for earnings less than the Company's allowed rate of return (id.).[265]

b. DOER

DOER opposes the Company's proposed earnings sharing mechanism (DOER Brief at 30). DOER contends that the proposed earnings sharing mechanism provided little or no incentive for the Company to improve productivity (id.). As an alternative to the Company's proposed earnings sharing mechanism, DOER proposes that the Department consider a mechanism whereby any returns gained in excess of a prescribed level during the term of the PBR plan, such as the authorized ROE, be returned to ratepayers in the event that the Company does not show productivity enhancement during the PBR period (id.).[266] DOER recommends that the Department compare the Company's average annual five-year productivity change over the five-year period of the PBR plan to a benchmark, defined as the average annual five-year productivity change over the five-year period for the Northeast peer group, in order to determine if any return of revenues is warranted (id. at 31). DOER recommends that this comparison be made by comparing the mean five-year productivity of the Company versus its peer group and if the Company falls within a range of one standard deviation of the benchmark (as measured by the five-year, weighted average ROE), no

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265 In other words, the Attorney General's recommended earnings sharing plan is "asymmetrical" with no impact on ratepayers stemming from returns below the Company's regulated rate of return.

266 The earnings sharing mechanism proposed by DOER was introduced for the first time on brief.

revenues in excess of the authorized rate of return would be returned to ratepayers (id. at 31). If the Company's performance is one standard deviation below the benchmark, then the Company would return any revenues in excess of the authorized rate of return to ratepayers (id.). Conversely, if the Company's performance is greater than one standard deviation above the benchmark, the Company shares the gains above the authorized rate of return, with 25 percent returned to ratepayers (id.).

c. Boston Gas

The Company contends that DOER's proposed earnings sharing mechanism is problematic and involves considerable implementation difficulties that "will make regulation more rather than less complex, and will increase regulatory burden" (Boston Gas Brief at 182). The Company did not address on brief the Attorney General's proposed earnings sharing mechanism.

3. Analysis and Findings

In prior proceedings, the Department has recognized the issue of uncertainty associated with setting the productivity factor. The Department has also recognized that earnings sharing could provide ratepayers a backstop to improper setting of the productivity factor. D.P.U. 94-50, at 197; D.P.U. 96-50 (Phase I) at 325. Specifically, the Department has stated that protection such as an earnings sharing mechanism was required for ratepayers. D.P.U. 96-50 (Phase I) at 325.

In the instant case, the circumstances remain the same. The Department must provide ratepayers with a backstop to improper setting of the productivity factor. The Department has

before it the following three proposals for an earnings sharing mechanism: (1) the Attorney General's plan that adjusts the Company's proposed deadbands; (2) DOER's proposed mechanism that compares the Company's cost-savings performance to its peers; and (3) the Company's earnings sharing mechanism that is identical to that approved in D.P.U. 96-50.

Turning first to DOER's proposal, we note that it is not clear how the mechanism works. First, DOER has not made clear what benchmark it is recommending for use in their proposed plan (DOER Brief at 31). While DOER initially recommends a "productivity-based" benchmark, the agency later settles upon [ROE] as the selected performance criteria. DOER does not adequately explain how its proposed mechanism operates in relation to the Company's authorized ROE if the Company's earnings exceed the five-year peer group average. Finally, DOER's proposal was introduced for the first time on brief and insufficient record evidence exists for the Department to evaluate DOER's plan. For these reasons, the Department rejects DOER's recommendation to implement a clawback mechanism.

The Attorney General's proposed earnings sharing mechanism is also flawed. The plan is incompletely developed. The Attorney General's position does not explain how his mechanism would work if the consumer dividend is not set at one percent. Because the record is insufficient to evaluate the proposal, the Department rejects the Attorney General's earnings sharing plan proposal.

Turning to the Company's proposed earnings sharing mechanism, as in D.P.U. 96-50, the Department still finds it necessary to protect ratepayers with an earnings sharing mechanism. The earnings sharing mechanism proposed by the Company is identical to that

proposed in D.P.U. 96-50 and approved by the Department in that adjudicated proceeding. We find the Company's proposed earnings sharing mechanism includes (1) a Company/ratepayer sharing ratio that provides Boston Gas with economic incentives, and (2) a bandwidth that balances Company and ratepayer risks, and finally it is consistent with Department precedent. Therefore, we approve the Company's proposed earnings sharing mechanism.

E. Pricing and Rate Design Flexibility

1. Introduction

Boston Gas proposes to maintain the same pricing flexibility allowed it under D.P.U. 96-50. This flexibility would allow the Company to allocate the price-cap increase or decrease within a rate class at its discretion, as long as each rate component increases by no more than the rate of inflation (Exh. KEDNE/JFB-1, at 27).

2. Position of the Parties

a. Bay State

Bay State supports the flexibility that Boston Gas is seeking to allocate the price-cap increases or decreases between rate elements within a class, as long as no rate component increases by more than the rate of inflation (Bay State Brief at 5, citing Exh. KEDNE/JFB-1, at 27; Exh. MDFA 1-9). Bay State argues that the flexibility sought by Boston Gas is consistent with the goals of incentive regulation, because it will reduce the need for rate reviews and detailed rate design proposals and will lead to reduced administrative and

regulatory cost in implementing Boston Gas' price-cap proposal (Bay State Brief at 5, citing D.P.U. 96-50 (Phase I) at 333-334; D.P.U. 94-158, at 64-66).

b. Boston Gas

Boston Gas states that the Company proposes to maintain the same pricing flexibility established in D.P.U. 96-50 because this mechanism functioned well during the operation of the first PBR plan (RR-DTE-52). Boston Gas argues that there are no circumstances that would have warranted a proposal by the Company to seek a change to the Department's decision in relation to the pricing flexibility under the proposed PBR plan (id.).

3. Analysis and Findings

The Company's proposal to retain some discretion in allocating each rate class' price-cap change to the individual rate components within the class is identical to the rate design flexibility approved for the Company in D.P.U. 96-50 and for Berkshire Gas Company in D.T.E. 01-56. D.P.U. 96-50 (Phase I) at 333-334; D.T.E. 01-56, at 26-27. No party opposes the Company's proposed rate design flexibility.

The Department agrees with the Company that it should retain some discretion in allocating the price-cap increase or decrease between rate elements within a class as long as no rate component increases by more than the rate of inflation. Allowing Boston Gas to set the rate component changes within a class should help to reduce intra-class subsidies and high bill impacts for individual customers. This flexibility gives the Company some intraclass rate discretion, while ensuring that each individual rate element cannot increase above the inflation rate for the duration of the PBR plan.

Therefore, consistent with Department precedent, we approve the rate design and pricing flexibility proposed by Boston Gas. D.P.U. 96-50 (Phase I) at 333-334; D.T.E. 01-56, at 26-27. Should the price-cap increase be greater than the rate of inflation, because of the recovery of exogenous costs, the Department directs the Company to increase each rate component price at no more than the rate provided for in the price-cap formula.

F. Service Quality

The Department has found that, because PBR introduces a financial incentive for the regulated firm to reduce costs, a well-designed PBR plan must include some form of protection against a reduction in service quality for monopoly customers. D.P.U. 96-50 (Phase I) at 304; D.P.U. 96-50-C, at 59-79; D.P.U. 94-50, at 235. See G.L. c. 164, § 1E. The PBR plan approved by the Department in D.P.U. 96-50 (Phase I) at 293-311, contained a service quality plan. Subsequent to that Order, the Department approved service quality guidelines for all gas and electric distribution companies in D.T.E. 99-84, at 42 (2001).[267] The Company then agreed to modify its service quality plan approved in D.P.U. 96-50 to incorporate the D.T.E. 99-84 guidelines. D.T.E. 99-84, Letter Order at 3-4 (April 17, 2002).

The Company did not include a service quality plan with its current proposal. Rather, the Company agreed that it remains subject to the Department's current service quality

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[267] The guidelines established by D.T.E. 99-84 apply to those distribution companies operating under either PBRs or merger-related or acquisition-related rate plans. See, e.g., D.T.E. 01-71A at 8-9, 12-18; MECo Service Quality, D.T.E. 01-71B at 6-26 (2002); D.T.E. 99-84, Letter Order at 5-6 (May 28, 2002); D.T.E. 99-84, Letter Order at 3-6 (April 17, 2002).

guidelines set forth in D.T.E. 99-84 (Tr. 13, at 1654; Tr. 18, at 2462-2463; Tr. 21, at 2768-2769;). Should the Department change these service quality guidelines, the Company agreed that it will adjust its service quality plan to incorporate those changes (Tr. 18, at 2462-2463; Tr. 21, at 2768-2769). Therefore, we find that Boston Gas is subject to the Department's current service quality guidelines set forth in D.T.E. 99-84 and any future changes to those guidelines.

Boston Gas' service quality guidelines require that its staffing levels be consistent with G.L. c. 164, § 1E(b), primarily by collective bargaining agreements. D.T.E. 99-84-B at 11-13 (2001). G.L. c. 164, § 1E(b) provides:

> In complying with the service quality standards and employee benchmarks established pursuant to this section, a distribution, transmission, or gas company that makes a performance based rate filing after the effective date of this act shall not be allowed to engage in labor displacement or reductions below staffing levels in existence on November 1, 1997, unless such are part of a collective bargaining agreement or agreements between such a company and the applicable organization or organizations representing such workers, or with the approval of the [D]epartment following an evidentiary hearing at which the burden shall be upon the company to demonstrate that such staffing reductions shall not adversely disrupt service quality standards as established by the [D]epartment herein.

The Attorney General argues that the Department should reject the Company's PBR plan because the Company has reduced its staffing levels since 1997 (Attorney General Brief at 116; Attorney General Reply Brief at 64). The Attorney General also requests that the Department impose a penalty for reducing its staffing levels from the 1997 levels (Attorney General Brief at 118). The Company responds to the Attorney General's argument, stating that, by its terms, G.L. c. 164, § 1E(b) does not apply to the Company because it had a PBR plan in effect prior to 1997 (Boston Gas Brief at 210). Further, the Company argues that its

collective bargaining agreements permit its current staffing levels (id. at 211; Boston Gas Reply Brief at 96).

There is no support for the Attorney General's request that Boston Gas' PBR plan be rejected and a penalty imposed because its current staffing levels do not equal the staffing levels in 1997. See, e.g., D.T.E. 01-56 (approving a PBR plan without establishing staffing level benchmark). Although G.L. c. 164, § 1E(b) imposes a benchmark regarding staffing levels, it does not include any penalty for changes to the benchmark. It does not require a PBR plan to be rejected if staffing levels are not determined. See D.T.E. 01-56, at 2, n.2. Further, there is no evidence that the Company's present staffing levels impair its service quality to customers. The Department has reviewed the Company's 2002 service quality report in Boston Gas Company, D.T.E. 03-14, Letter Order at 3 (September 30, 2003) and found no deterioration in quality of service. Therefore, the Department rejects the Attorney General's request. The subject of staffing levels is an important matter directly affecting distribution companies' service quality. Staffing levels must be addressed in an appropriate forum where interested parties may participate.

G. Compliance Filings

1. Introduction

The Company proposes that price changes under its price-cap formula would be based on a compliance filing establishing rates for effect on November 1st each year, starting on November 1, 2004 (Exh. KEDNE/JFB-1, at 27). Under the Company's proposal, there will be five annual compliance filings made to the Department (id.). The last rate adjustment

would take effect on November 1, 2008 (id.). After the initial five-year term of the PBR plan, the Company proposes to notify the Department each year of its intention to continue the PBR plan for one more year. Beginning June 1, 2009, and each June 1st thereafter, the Company will notify the Department of its intent to submit a compliance filing on September 15th (id.). No party commented on the Company's proposal for the submission of annual compliance filings.

2. Analysis and Findings

In D.P.U. 96-50 (Phase I) at 338, the Department directed that each year Boston Gas must submit the following documentation supporting the base rate adjustments: (1) the determination of normal billing determinants and revenues to determine the weighted average price to which the price-cap will be applied; (2) a calculation of the new price-cap, including documentation of the exogenous factors and capital cost changes; (3) development of new rates consistent with the annual price-cap calculation; and (4) class-by-class bill impacts, including gas costs, comparing the proposed rates to the then-current rates. Also, the Department found in D.P.U. 96-50 (Phase I) at 338, that Boston Gas' weighted average price for the previous year would be calculated using revenues and billing determinants normalized for weather. Lastly, the Department emphasized that "to the extent the Company submits the annual filings in a clear and comprehensive manner, with supporting data, this will facilitate the review of such filings by the Department and other parties." D.P.U. 96-50 (Phase I) at 339.

The Department directs Boston Gas to submit in its annual compliance filings the same supporting documentation that we required for the Company in D.P.U. 96-50 (Phase I) and, as

part of these filings, to submit its weighted average price for the previous year calculated using revenues and billing determinants normalized for weather. The Company is directed to submit its annual compliance filings each September 15th commencing in 2004 and continuing for the ten-year term of the PBR plan. Submission of annual plans is not optional or contingent on intent to continue the PBR plan from year to year after the initial five years. Subject to the discussion at Section VII.C.3, above, the PBR plan shall continue in effect for a total of ten consecutive years starting November 1, 2003, with the last adjustment taking effect on November 1, 2013.

IX. "ON-TRACK" LOW-INCOME ASSISTANCE PROGRAM

A. Introduction

Boston Gas proposes to implement a program, called "On-Track," which is designed to help low-income customers reduce their energy consumption and improve their bill-payment behavior (Exhs. KEDNE/JFB-1, at 13; MCP 2-12).[268] The On-Track program includes education, counseling, and advocacy. The Company structured the program to enable low-income customers with a history of payment problems to better manage their finances (Exhs. KEDNE/JFB-1, at 13; MCP 2-13). The primary components of the On-Track program are: (1) individualized customer services; (2) a financial and energy management home-study course; and (3) arrears forgiveness (Exh. KEDNE/JFB-1, at 14). According to the Company,

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[268] To be eligible for the On-Track program a customer must: (1) be receiving gas service under the residential heating rate (i.e., Rate R-3); (2) have a gross income of 250 percent or less of the federal poverty level; (3) not be eligible for any public assistance that would cover utility arrears; and (4) have a history of payment problems with the Company (Exh. KEDNE/JFB-1, at 14).

a similar program has been operating in Keyspan's New York service territory since 1996 (Exhs. KEDNE/JFB-1, at 13; MCP 2-10).

Participants in the On-Track program will first receive a financial analysis and a payment plan to address arrears and future bills (Exh. KEDNE/JFB-1, at 14). A customer representative will be assigned to call the participant once a month to review how they are doing under the payment plan (id.). If necessary, the customer representative will review the educational and financial material previously provided to the customer. Participants with the most difficulty managing payments, or those who have special needs, will be referred to the Company's in-house social worker (Exh. KEDNE/JFB-1, at 14; MCP 2-13). The social worker will provide counseling and assistance with money management skills, and help the participant to access resources such as public benefits, reverse mortgages, or kinship foster-care payments (Exhs. KEDNE/JFB-1, at 14; MCP 2-13). Also, the Company proposes to coordinate the On-Track program services with its energy-efficiency programs (Exhs. KEDNE/JFB-1, at 14; MCP 2-13).

Finally, if a customer successfully completes the On-Track program and fulfills his or her financial agreement with the Company, the customer will be forgiven account arrears of up to $400 (Exh. KEDNE/JFB-1, at 15). The customer will receive two $100 credits during the first twelve months of the program and a final $200 credit at the end of the program (Exh. MCP 2-17(a); Tr. 12, at 1505). The Company has not proposed to recover any costs of the On-Track program, including arrearage forgiveness, in this case (Exh. AG 22-12).

B. Positions of the Parties

1. MassCAP

MassCAP strongly supports the Company's proposed On-Track program (MassCAP Brief at 7-11). MassCAP states that customers participating in a similar program in Keyspan's New York service territory annually pay $190 more towards their energy bills than they did prior to entering the program (id. at 7). MassCAP argues that the On-Track program is well designed and very successful, and claims that in New York, the program enrolls approximately 1,500 customers every twelve to 18 months (id. at 7-8, citing Exh. MCP 2-10). Moreover, MassCAP asserts that the program is a "win-win," in that the Company benefits by having to engage in less collection activity while lowering its bad debt (id. at 8). Finally, MassCAP urges the Department to encourage other companies to offer similar programs to payment-troubled customers (id. at 10-11).

2. Boston Gas

Boston Gas argues that, based on Keyspan's experience in its New York service territory, the On-Track program should be effective for both the Company and the participating customers (Exh. KEDNE/JFB at 15). According to the Company, testing of participants in New York showed that they increased their understanding of financial management concepts, which led to improved money management and bill payment (id.). In addition, since implementing On-Track in New York, the Company states that Keyspan has experienced fewer customer termination actions and contacts concerning nonpayment (id.).

C. Analysis and Findings

The On-Track program can educate and counsel low-income ratepayers with poor bill payment history in methods to better manage their finances. The On-Track program may likely enable the Company to lower its bad debt expense which, in the future, could benefit all ratepayers. Evidence indicates that a similar program has enjoyed some success in New York. Further, the Company has not included any of the costs associated with the program, including arrearage forgiveness, in rates. Boston Gas has, therefore, demonstrated that its On-Track program may benefit its low-income customers, and, thereby, all of the Company's ratepayers. Accordingly, based on the foregoing, the Department supports the implementation of the On-Track program and, if managing payment and bad debt programs in this way is beneficial to all ratepayers, encourages all gas and electric distribution companies to explore the implementation of low-income assistance programs similar to On-Track.

X. SCHEDULES

XI. ORDER

Accordingly, after due notice, hearing and consideration, it is

ORDERED: That the tariffs M.D.T.E. 1209 through M.D.T.E. 1225, filed by Boston Gas Company on April 16, 2003, to become effective May 1, 2003, are DISALLOWED; and it is

FURTHER ORDERED: That Boston Gas file new schedules of rates and charges designed to increase base revenues by $23,799,928; and it is

FURTHER ORDERED: That Boston Gas Company shall file all rates and charges required by this Order and shall design all rates in compliance with this Order; and it is

FURTHER ORDERED: That Boston Gas shall comply with all other orders and directives contained herein; and it is

FURTHER ORDERED: That the new rates shall apply to gas consumed on or after the date of this Order, but unless otherwise ordered by the Department, shall not become effective earlier than seven (7) days after they are filed with supporting data demonstrating that such rates comply with this Order.

By Order of the Department,

/S/

Paul G. Afonso, Chairman

/S/

James Connelly, Commissioner

/S/

W. Robert Keating, Commissioner

/S/

Eugene J. Sullivan, Jr., Commissioner

/S/

Deirdre K. Manning, Commissioner

Appeal as to matters of law from any final decision, order or ruling of the Commission may be taken to the Supreme Judicial Court by an aggrieved party in interest by the filing of a written petition praying that the Order of the Commission be modified or set aside in whole or in part.

Such petition for appeal shall be filed with the Secretary of the Commission within twenty days after the date of service of the decision, order or ruling of the Commission, or within such further time as the Commission may allow upon request filed prior to the expiration of twenty days after the date of service of said decision, order or ruling. Within ten days after such petition has been filed, the appealing party shall enter the appeal in the Supreme Judicial Court sitting in Suffolk County by filing a copy thereof with the Clerk of said Court. (Sec. 5, Chapter 25, G.L. Ter. Ed., as most recently amended by Chapter 485 of the Acts of 1971).