The Commonwealth of Massachusetts

DEPARTMENT OF PUBLIC UTILITIES

D.P.U. 14-150 October 30, 2015

Petition of NSTAR Gas Company, pursuant to G.L. c. 164, § 94 and 220 C.M.R. § 5.00 et seq., for Approval of a General Increase in Gas Rates and a Revenue Decoupling Mechanism.

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I. INTRODUCTION

On December 17, 2014, NSTAR Gas Company ("NSTAR Gas" or "Company") filed a petition with the Department of Public Utilities ("Department") for a general increase in gas rates. NSTAR Gas' last base rate proceeding was in 2005. NSTAR Gas Company, D.T.E. 05-85 (2005).

NSTAR Gas operates as a wholly-owned subsidiary of Yankee Energy System, Inc., a holding company that is a wholly-owned subsidiary of Northeast Utilities, n/k/a Eversource Energy (Exh. NSTAR-WJA-1, at 14).[1] The Company is engaged in the retail distribution and sale of natural gas to approximately 276,000 customers in 51 communities in central and eastern Massachusetts (Exh. NSTAR-WJA-1, at 14-15).

In the instant case, the Company seeks an increase in rates to generate $ 35.2 million in additional revenues. The requested rate increase is designed to recover: (1) 23.2 million in additional revenues through base distribution rates; and (2) 12.0 million in additional revenues through other rate recovery mechanisms (Exhs. NSTAR-MFF-2, Sch. MFF-2 (August 21, 2015); NSTAR-MFF-4, Sch. 1 (August 21, 2015)).[2] The cost of service component of the Company's filing is based on a test year of January 1, 2013, through December 31, 2013 (Exh. NSTAR-MFF-1, at 3). The Company's requested increase represents an approximate

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1 Effective February 2, 2015, Northeast Utilities and all of its subsidiaries began doing business as Eversource Energy (Exhs. DPU-5-2; DPU-8-28). However, for purposes of this Order, the Department will refer to the relevant entities as memorialized herein.

2 In its original filing, NSTAR Gas sought to recover $33.9 million in additional revenues through base distribution rates (Exhs. NSTAR-MFF-2, Sch. MFF-2; NSTAR-MFF-4, Sch. 1). During the course of the proceeding, NSTAR Gas reduced its requested base distribution rate increase to $23.2 million (Exhs. NSTAR-MFF-2, Sch. MFF-2 (August 21, 2015); NSTAR-MFF-4, Sch. 1 (August 21, 2015)).

15.0 percent increase in base distribution revenues, or an increase of 8.3 percent in current annual operating revenues.

The Company's requested rate increase includes the proposed recovery of merger-related costs and certain exogenous costs. The requested rate increase also includes a purported increase in costs associated with the Company's purchase of liquefied natural gas services from an affiliate, Hopkinton LNG Corp. ("HOPCO"). Further, as part of the filing, NSTAR Gas sets forth proposals associated with the sale of the Company's appliance business and changes to the operation of its Home Heating Protection Plan ("HHPP") business. Finally, the Company proposes, pursuant to Investigation into Rate Structures that will Promote Efficient Deployment of Demand Resources, D.P.U. 07-50-A (2008), to implement a rate mechanism to decouple its gas revenues from its sales.

The Department docketed this matter as D.P.U. 14-150, and suspended the effective date of the proposed rate increase until November 1, 2015, to investigate the propriety of the Company's petition. However, as the result of a rate freeze in place since 2012, as discussed in further detail below in Sections IV.B.6.c and VI.A.1.a, any new rates will not become effective until January 1, 2016. See NSTAR/Northeast Utilities Merger, D.P.U. 10-170-B at 18, 36, 107 (2012).

II. PROCEDURAL HISTORY

On January 5, 2015, the Department granted intervenor status to the Low Income Weatherization and Fuel Assistance Program Network ("Low Income Network"). On January 8, 2015, the Department granted intervenor status to the Department of Energy Resources ("DOER"). On January 13, 2015, the Attorney General of the Commonwealth of

Massachusetts ("Attorney General") filed a notice of intervention pursuant to G.L. c. 12, § 11E(a).[3]

On January 22, 2015, the Department granted limited participant status to Bay State Gas Company, d/b/a Columbia Gas of Massachusetts; The Berkshire Gas Company; Liberty Utilities (New England Natural Gas Company) Corp. d/b/a Liberty Utilities; and Fitchburg Gas and Electric Light Company, d/b/a Unitil; and, jointly to The Energy Consortium ("TEC"), Power Options, Inc., and Associated Industries of Massachusetts. Finally, on January 29, 2015, the Department granted limited participant status to Boston Gas Company and Colonial Gas Company, each d/b/a National Grid.

Pursuant to notice duly issued, the Department held five public hearings in the Company's service territory: (1) in Dedham on January 29, 2015; (2) in New Bedford on February 3, 2015; (3) in Plymouth on February 4, 2015; (4) in Boston on April 7, 2015; and (5) in Worcester on April 9, 2015. The Department also received written comments from public officials and several NSTAR Gas ratepayers.

The Department held 14 days of evidentiary hearings from June 2, 2015, through June 23, 2015. In support of the Company's filing, the following witnesses, all of whom are employed by Northeast Utilities Service Company, d/b/a Eversource Service Company ("NUSCO"), provided testimony: (1) William J. Akley, president of gas distribution business; (2) Eric H. Chung, director of revenue requirements – New Hampshire; (3) Michael F. Farrell, director of revenue and regulatory accounting; (4) Sasha Lazor, director of compensation;

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[3] On January 23, 2015, pursuant to G.L. c. 12, § 11E(b), the Department approved the Attorney General's notice of retention of experts and consultants. NSTAR Gas Company, D.P.U. 14-150, Order on Attorney General's Notice of Retention of Experts and Consultants (January 23, 2015).

(5) Bernard B. Peloquin, director of benefits and human resources operations; (6) Leanne M. Landry, director of investment planning and budgets; (7) Richard D. Chin, manager of rates; (8) Douglas P. Horton, director of revenue requirements - Massachusetts; (9) Emilie G. O'Neil, director of corporate finance and cash management; (10) Philip J. Lembo, vice president and treasurer; (11) James P. Davis, director of gas systems operations; (12) Robert H. Martin, manager of investment planning; (13) Karen A. Keough, manager of credit and collections; and (14) Camilo Serna, president of strategic planning and policy.[4] In addition to NUSCO personnel, the following outside consultants provided testimony on behalf of NSTAR Gas: (1) Robert B. Hevert, managing partner, Sussex Economic Advisors; (2) John J. Spanos, consultant, Gannett Fleming Valuation and Rate Consultants, LLC; (3) David A. Heintz, vice president, Concentric Energy Advisors; (4) James D. Simpson, senior vice president, Concentric Energy Advisors; and (5) Michael E. Barrett, principal, M. Barrett Consulting, LLC.

The Attorney General sponsored the testimony of the following witnesses: (1) J. Randall Woolridge, Ph.D., professor of finance, Goldman, Sachs & Co. and Frank P. Smeal Endowed University Fellow in business administration at the University Park Campus of the Pennsylvania State University; (2) Allen R. Neale, consultant, La Capra Associates, Inc.; (3) Alvaro E. Pereira, managing consultant, La Capra Associates, Inc.; (4) Rebecca Bachelder, president, Blueflame Consulting, LLC; (5) Jacob Pous, consultant, Diversified Utility Consultants, Inc.; and (6) David J. Effron, consultant, Berkshire Consulting Services.

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4 The Company submitted pre-filed testimony from Charles R. Goodwin, who subsequently was unavailable to appear at the evidentiary hearings. The Department and parties assented to the Company's proffer of Richard D. Chin to adopt Mr. Goodwin's pre-filed testimony and discovery responses, and to appear for cross-examination.

The Low Income Network submitted its initial brief on July 20, 2015. The Attorney General and DOER submitted initial briefs on July 21, 2015. NSTAR Gas submitted its initial brief on August 6, 2015. The Attorney General and TEC submitted reply briefs on August 17, 2105. The Company submitted its reply brief on August 21, 2015. The evidentiary record consists of approximately 2,500 exhibits and responses to 49 record requests.

III. REVENUE DECOUPLING MECHANISM

A. Introduction

In D.P.U. 07-50-A at 32, 81-82, the Department directed each electric and gas distribution company to propose a full revenue decoupling mechanism in its next base rate proceeding. Decoupling severs the link between a company's revenues and sales through a periodic reconciliation of the actual revenue that a company bills to its ratepayers with a specified target revenue level. Massachusetts Electric Company/Nantucket Electric Company, D.P.U. 09-39, at 7 (2009). The Department stated that the objective of decoupling is the "elimination of financial barriers to the full engagement and participation by the Commonwealth's investor-owned distribution companies in demand-reducing efforts." D.P.U. 07-50-A at 4. The Department concluded that "a full decoupling mechanism best meets our objectives of: (1) aligning the financial interests of the companies with policy objectives regarding the efficient deployment of demand resources; and (2) ensuring that the companies are not harmed by decreases in sales associated with any increased use of demand resources." D.P.U. 07-50-A at 31-32.

In directing electric and gas distribution companies to adopt full decoupling, the Department acknowledged that decoupling would remove their opportunity to earn additional revenues from growth in sales between base rate proceedings and further acknowledged that such revenues typically funded, among other things, increased operations and maintenance ("O&M") expenses as well as system reliability and capital investment projects. D.P.U. 07-50-A at 48, 87. Accordingly, the Department stated that it would consider company-specific proposals that account for the effects of increased capital investments and inflation on target revenue. D.P.U. 07-50-A at 50.

B. Company's Proposal

1. Introduction

The Company's proposed revenue decoupling mechanism is described in its Revenue Decoupling Adjustment Clause ("RDAC") tariff, proposed M.D.P.U. No. 409 (Exh. NSTAR-RDC-6, at 139-144). The Company's proposed revenue decoupling mechanism is designed to fully separate the link between the revenues the Company is allowed to collect and the amount of gas that it delivers to its customers (Exh. NSTAR-CRG-1, at 2; Tr. 9, at 827-828). The Company's proposed revenue decoupling mechanism reconciles actual base distribution revenues-per-customer, adjusted to remove base revenues for new customers added after the end of the test year, with the benchmark distribution revenues-per-customer established in this proceeding, (Exh. NSTAR-CRG-1, at 3, 14). The Company proposes to calculate actual versus benchmark revenues-per-customer for three customer class groups: (1) residential heating; (2) residential non-heating; and (3) C&I (Exh. NSTAR-CRG-1, at 14-15).

The Company proposes to reconcile its distribution revenues and develop rates on a semi-annual basis (i.e., November through April for the peak season and May through October for the off-peak season) (Exh. NSTAR-CRG-1, at 14-15). NSTAR Gas proposes to exclude special contract and interruptible customers (and associated revenues) from the revenue decoupling mechanism (Exh. NSTAR-CRG-1, at 14). In addition, the Company proposes to retain the incremental revenues associated with residential upgrades from non-heating to heating service (Exh. NSTAR-CRG-1, at 14-15). Several components of the Company's proposed revenue decoupling mechanism are discussed in further detail below.

2. Revenues-Per-Customer Approach

The Company proposes to calculate a seasonal benchmark revenues-per-customer based on the revenue requirements approved by the Department in this proceeding for the peak and off-peak periods for the three customer class groups identified above, and based on the test year number of customers for each of the three customer class groups (Exhs. NSTAR-CRG-1, at 15; NSTAR-CRG-2; DPU-2-5). Specifically, NSTAR Gas proposes to calculate the benchmark revenues-per-customer for each of the three customer class groups by dividing the class' revenues by the average number of customers (exclusive of new customers) for each month of the test year (Exhs. NSTAR-CRG-1, at 16; NSTAR-CRG-2, Sch.CRG-1). The Company proposes to calculate monthly revenues by multiplying the distribution rates approved in this case by the billing determinants for each month of the test year that are used to design the approved distribution rates (Exh. NSTAR-CRG-1, at 15-16). NSTAR Gas proposes to make the revenues-per-customer calculation on a monthly basis to accommodate a monthly accounting entry that the Company will make, and also because the initial revenue decoupling calculation and filing will not include a full six-month seasonal period as a result of the effective date of new rates (i.e., the initial period will be January 1, 2016 through April 30, 2016) (Exh. NSTAR-CRG-1, at 16).

NSTAR Gas proposes to calculate the actual monthly revenues-per-customer for each of the three customer class groups by: (1) tracking total base distribution revenues and number of customers; (2) segregating out the revenues and customer counts associated with new customers; (3) aggregating the remaining monthly actual revenues and customer counts across the three customer class groups; and (4) dividing the aggregated amounts by the total billed customers in each group (Exh. NSTAR-CRG-1, at 19). At the end of each peak or off-peak period, the Company proposes to divide the sum of the six months of actual revenues by the average number of customers per month (exclusive of revenues and customer counts associated with new customer additions) for the corresponding six months to derive an average actual base distribution revenues-per-customer for each customer class group (Exhs. NSTAR-CRG-1, at 19; NSTAR-RDC-6, at 142 (proposed M.D.P.U. No. 409, § 6.1)).

3. Treatment of New Customers

As noted above, NSTAR Gas proposes to exclude new customers and their associated base distribution revenues from the revenues-per-customer calculations[5] (Exh. NSTAR-CRG-1, at 3, 14, 17). In this context, the Company defines a new customer as a post-test year customer addition in which capital investments (i.e., mains extensions or investments in new service installations and upgrades) are required for connection to the distribution system (Exh. NSTAR-CRG-1, at 17). The Company intends to track new customers in its billing and record keeping systems (Exh. NSTAR-CRG-1, at 17).

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5 The Company's proposal will enable it to retain incremental revenues from newly-connected customers (Exh. NSTAR-CRG-1, at 17-19).

4. Revenue Decoupling Adjustments

As set forth above, the Company will calculate seasonal revenues-per-customer benchmarks, followed by actual revenues-per-customers amounts. The Company proposes to reconcile any differences between the two calculations as follows. First, the Company will calculate the difference between the actual billed base revenues-per-customer and the benchmark base revenues-per-customer for the three customer class groups for the recently completed peak or off-peak period (Exh.NSTAR-CRG-1, at 20). The Company then will multiply the difference for each customer class group by the average actual number of existing customers billed in that period and for that group to derive the appropriate revenue adjustment (i.e., a credit or charge) for each customer class group (Exh.NSTAR-CRG-1, at 20). Next, the Company will add the sum of the revenue adjustment for each customer class group to the revenue decoupling reconciliation, including carrying costs, to derive the revenue decoupling adjustment (see Exhs. NSTAR-CRG-1, at 21; NSTAR-RDC-6, at 142 (proposed M.D.P.U. No. 409, § 6.1)).[6]

The Company proposes to allocate the revenue decoupling adjustment among four rate class sectors (i.e., residential, small C&I, medium C&I, and large C&I) (Exhs. NSTAR-CRG-1, at 20; NSTAR-RDC-6, at 140 (proposed M.D.P.U. No. 409, § 4.0)). The Company proposes to determine the revenue decoupling adjustment factor for each rate class sector by dividing each sector's allocated portion of the revenue adjustment by a projection of period sales volumes (inclusive of all firm sales and firm transportation throughput) for the subsequent peak or

6 NSTAR Gas proposes that the seasonal over- or under-recovery of revenues include monthly interest calculated at the prime lending rate (Exhs. NSTAR-CRG-1, at 21; DPU-4-3).

off-peak period (Exhs. NSTAR-CRG-1, at 20; NSTAR-RDC-6, at 143 (proposed M.D.P.U. No. 409, § 6.2)).

5. Revenue Cap

The Company proposes a three percent cap on any future revenue decoupling adjustment (Exhs. NSTAR-CRG-1, at 23; DPU-2-4). For the purpose of implementing the cap, the Company proposes to compare the over- or under-recovery of revenues to the total revenues of its firm customers (Exh. NSTAR-CRG-1, at 23). In developing total revenues, NSTAR Gas proposes to impute a level of gas cost revenues for transportation customers based on its cost of gas adjustment rate (Exh. NSTAR-CRG-1, at 23). If the level of the revenue decoupling adjustment over- or under-recovery exceeds three percent of total revenues, then the Company will cap the revenue decoupling adjustment at three percent (Exh. NSTAR-CRG-1, at 23). To the extent that the application of the revenue cap results in a revenue decoupling adjustment that does not fully recover the actual revenues-per-customer, the Company proposes to defer the difference and recover it in a subsequent revenue decoupling adjustment filing for the corresponding peak or off-peak period, with carrying costs at the prime lending rate, to the extent that there is room under the cap for that filing period (see Exhs. NSTAR-CRG-1, at 21; NSTAR-RDC-6, at 142 (proposed M.D.P.U. No. 409, § 6.1); DPU-4-3).

6. Revenue Decoupling Adjustment Filings

NSTAR Gas proposes to submit its initial revenue decoupling adjustment filing in mid-September 2016, at least 45 days ahead of the peak season decoupling adjustment (Exh. NSTAR-CRG-1, at 22). This filing will reconcile any differences between the monthly benchmark revenues-per-customer and the actual revenues-per-customer for the period

January 1, 2016 (when new rates take effect) through April 30, 2016 (Exh. NSTAR-CRG-1, at 21). The Company will multiply the revenues-per-customer difference for the four month period by the number of actual customers (excluding new customers added) for each of the three customer groups, and then total the result for each group to derive the initial revenue decoupling credit or charge, subject to the three percent revenue cap (Exhs. NSTAR-CRG-1, at 21-23; NSTAR-CRG-2, Sch. CRG-3). The Company proposes to institute the initial credit or charge effective November 1, 2016 (Exh. NSTAR-CRG-1, at 22).

The Company states that at the conclusion of the initial off-peak period, which ends in October 2016, a similar reconciliation process will occur and result in the next revenue decoupling adjustment filing at least 45 days ahead of May 1, 2017, the effective date of the off-peak period revenue decoupling adjustment (Exh. NSTAR-CRG-1, at 23). NSTAR Gas intends to continue this seasonal filing process until new base rates are approved in a subsequent rate proceeding (Exh. NSTAR-CRG-1, at 23).

C. Positions of the Parties

1. Attorney General

The Attorney General argues that the Company's C&I customer classes should not be grouped together as one class for the purpose of the application of revenues-per-customer to calculate the revenue decoupling adjustment (Attorney General Brief at 79). Rather, the Attorney General argues that the C&I rate classes should be grouped by load factor for the purposes of revenue allocation and revenues-per-customer application (Attorney General Brief at 79). Specifically, the Attorney General argues that the C&I customer classes should be separated into two groups: (1) low load factor rate classes (i.e., rate classes G-41, G-42 and

G-43), and (2) high load factor rate classes (i.e., rate classes G-51, G-52 and G-53) (Attorney General Brief at 79-80). The Attorney General further contends that the resulting revenue decoupling adjustment should be allocated to the customer classes according to revenues for the same C&I load factor-based customer groups, and then by volumes within the customer class group (Attorney General Brief at 83; Attorney General Reply Brief at 40).

In support of her position, the Attorney General contends that the Company's proposal to group all C&I customers together disproportionately harms (or benefits) the high load factor rate classes by allocating to them a portion of the revenue shortfalls (or windfalls) created by low load factor classes due to changes in use associated with weather or energy efficiency programs (Attorney General Brief, at 80, 82). For example, the Attorney General contends that if revenue decoupling had been in place from 2004 to 2013, the Company would have collected cumulatively more than $15 million in additional decoupling revenues due to warmer than normal weather (Attorney General Brief at 80-81, citing Exh. DPU-2-19, Att.). According to the Attorney General, a majority of the revenue variance due to weather was attributable to low load factor rate classes and, therefore, under the Company's proposal, high load factor rate classes would have been disproportionately burdened with revenue decoupling "costs" they did not cause (Attorney General Brief at 81, citing Exh. AG-RSB-6, at 13; AG-22-1 Att.; see also Attorney General Reply Brief at 40-41). Further, the Attorney General argues that under the Company's proposal, high load factor customers would unfairly assume some of the revenue responsibility resulting from lower revenues-per-customer low load factor customers who continue to install energy efficiency measures that lower their heating load (Attorney General Reply Brief at 41, citing Exh. AG-RSB-6, at 12).

Based on these examples, the Attorney General argues that the Company's proposed grouping of its C&I customer classes into one group for purposes of decoupling violates the Department's rate design principles of cost causation and fairness (Attorney General Brief at 79-83; Attorney General Reply Brief at 40-42). Accordingly, the Attorney General recommends the Department adopt the aforementioned revisions to the Company's proposal (Attorney General Brief at 83; Attorney General Reply Brief at 40, 42).

2. DOER

DOER supports the Attorney General's recommendation to require the Company to group customers by load factor (as opposed to size) for the purpose of determining revenues-per-customer and reconciling target revenues to actual revenues (DOER Brief at 6-7). DOER contends that grouping customers by load factor is appropriate because the greatest variance in the Company's sales is caused by weather variability (DOER Brief at 7, citing Exh. AG-RSB-6, at 13). Therefore, according to DOER, customer grouping by load factor preserves the rate design principles of cost causation and efficiency (DOER Brief at 7).

In addition, DOER notes that the Company's revenue decoupling mechanism adjusts its revenues for all variances in sales and not just those caused by the Company's energy efficiency programs (DOER Brief at 7). DOER asserts that load-factor grouping maintains the alignment of the Company's interests with its deployment of energy efficiency equally as well as the Company's proposed grouping but in a way that is more closely aligned with customer use (DOER Brief at 7).

3. TEC

TEC supports the Attorney General's recommendation regarding the grouping of C&I customers by load factor (TEC Reply Brief at 5). Further, TEC agrees with the Attorney General that the resulting revenue decoupling adjustment should be allocated to customer classes according to revenues for the same C&I load factor based customer groups, and then by volumes within the customer class group (TEC Reply Brief at 5).

TEC argues that grouping all C&I customers together, as proposed by the Company, disproportionately harms or benefits high load factor rate classes by assigning to these classes a portion of the shortfalls or windfalls created by low load factor rate classes, which are due primarily to weather, heating-related load management, or energy efficiency programs (TEC Reply Brief at 5). According to TEC, the Department's rate design principles of cost causation and fairness require a rate design that assigns cost responsibilities to the customer classes that cause the costs (TEC Reply Brief at 5).

4. Company

NSTAR Gas argues that its proposed revenue decoupling mechanism is consistent with the decoupling mechanisms approved by Department for other gas companies (Company Brief at 5-6, citing New England Gas Company, D.P.U. 10-114 (2011); Boston Gas/Essex Gas/Colonial Gas, D.P.U. 10-55 (2010); Bay State Gas Company, D.P.U. 09-30 (2009); D.P.U. 07-50-A). In particular, the Company contends that its proposal to establish revenues-per-customer benchmarks for three customer groups (i.e., residential non-heating, residential heating, and C&I) is identical to the model approved by the Department for other gas companies and that those companies have operated their revenue decoupling mechanisms for several years without the need to modify the groupings (Company Brief at 8, citing D.P.U. 10-114, at 23; D.P.U. 10-55, at 40; D.P.U. 09-30, at 88-89; Company Reply Brief at 62).

The Company argues that the purpose of a revenue decoupling mechanism is to align the interests of a distribution company with its deployment of energy efficiency programs (Company Brief at 9, citing Exh. NSTAR-Rebuttal-3, at 9). Accordingly, the Company contends that customer size is a more appropriate criterion than load factor for grouping customer classes in a decoupling mechanism (Company Brief at 9, citing Investigation by the Department of Public Utilities Pursuant to Chapter 209, Section 51 of the Acts of 2012, An Act Relative to Competitively Priced Electricity in the Commonwealth, D.P.U. 12-126, at 7 (2013)).

In addition, the Company argues that it is not appropriate to allocate revenue recovery through a revenue decoupling mechanism to customer groups based on weather sensitivity, where the revenue decoupling mechanism is intended to address revenue loss as a result of load conservation associated with energy efficiency and other initiatives, because such treatment will create anomalies that will undermine the operation of the revenue decoupling mechanism (Company Brief at 9, citing Exh. NSTAR-Rebuttal-3, at 9-10)). The Company contends that no such anomalies exist when revenue decoupling is structured by customer class (Company Brief at 10). Finally, the Company contends that the separation of the C&I classes into two groups would result in a higher revenues-per-customer benchmark for high load factor customers as compared to low load factor customers (Company Reply Brief at 61-62). The Company asserts that the difference in revenues-per-customer could provide an inappropriate incentive for a company to encourage low load factor customers to increase their usage and become high load factor customers, because high load factor customers would have lower volumetric rates (Company Reply Brief at 62). In this regard, the Company claims that the potential for customer migration is significant (Company Reply Brief at 62, citing Exh. AG-9-1).[7]

D. Analysis and Findings

1. Introduction

Relying upon our delegated authority under G.L. c. 164, § 94 to prescribe the rates and prices that utilities may charge, the Department has adopted decoupled rates as the model for all future ratemaking proceedings. Investigation into Rate Structures that will Promote Efficient Deployment of Demand Resources, D.P.U. 07-50-B at 26 (2008), citing Boston Edison Co. v. City of Boston, 390 Mass. 772, 779 (1984). In D.P.U. 07-50-A at 24, the Department found that promoting the implementation of all cost-effective demand resources is a high priority. The Department stressed that to realize the full potential of demand resources, it is essential to leverage the distribution companies' relationships with customers as well as with any other entities that will be engaged in the development and deployment of such demand resources. D.P.U. 07-50-A at 25. In considering the various ratemaking alternatives that would promote the implementation of all cost-effective demand resources, the Department concluded that a full revenue decoupling mechanism best meets the objectives of: (1) aligning the financial interests of the companies with policy objectives regarding the efficient deployment of demand resources; and (2) ensuring that the companies are not harmed by decreases in sales associated with any increased use of demand resources. D.P.U. 07-50-A at 31-32. The Department noted that the

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[7] The Company states that in 2012, 337 customers moved from a low load factor class to a high load factor class. In 2013, 120 customers moved from a low load factor class to a high load factor class. Finally, in 2014, 132 customers moved from a low load factor class to a high load factor class (Company Reply Brief at 62, citing Exh. AG-9-1).

conclusions reached in D.P.U. 07-50-A represented general statements of policy and that issues such as the equity and appropriateness of specific cost allocations and revenue recovery proposals would be investigated and addressed based on the evidentiary record in the adjudication of a distribution company's individual proposal to employ rates that decouple its revenues from its sales. D.P.U. 07-50-B at 28-29. Accordingly, the Department will evaluate the appropriateness of each mechanism on a case-by-case basis, taking into consideration all aspects of the proposal and any relevant circumstances. D.P.U. 07-50-A at 50.[8]

2. Revenues-Per-Customer Approach

As set forth above, NSTAR Gas proposes a revenue decoupling mechanism that is intended to fully sever the link between sales and revenues (Exh. NSTAR-CRG-1, at 2; Tr. 9, at 827-828). The Company's proposal uses a revenues-per-customer approach that is consistent with the method endorsed by the Department in D.P.U. 07-50-A at 48-50. This general approach is also consistent with revenue decoupling mechanisms approved for other gas companies. See Fitchburg Gas and Electric Light Company, D.P.U. 11-01/D.P.U. 11-02, at 114-115 (2011); D.P.U. 10-114, at 23; D.P.U. 10-55, at 40; D.P.U. 09-30, at 89. Accordingly, the Department accepts NSTAR Gas' proposed revenues-per-customer approach as the framework for the Company's revenue decoupling mechanism in this case.

3. Treatment of New Customers

NSTAR Gas proposes to exclude new customers and their associated base distribution revenues from the revenue decoupling mechanism until the Company's next general rate case

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[8] In determining the propriety of rates, prices and charges, the Supreme Judicial Court has stated that the Department must find that they are just and reasonable. See Attorney General v. Department of Telecommunications and Energy, 438 Mass. 256, 264 n.13 (2002); Attorney General v. Department of Public Utilities, 392 Mass. 262, 265 (1984).

(Exh. NSTAR-CRG-1, at 3, 14, 17). The Department's long standing precedent regarding the ratemaking treatment of incremental revenues from new customers after rates have been set allows a company to retain those incremental revenues until its next base rate case. D.P.U. 10-55, at 45 D.P.U. 09-30, at 94 & n.50; Bay State Gas Company, D.T.E. 05-27, at 75, 79, 80 (2005); Boston Gas Company, D.T.E. 03-40, at 48 (2003); Boston Gas Company, D.P.U. 88-67 (Phase I) at 282-284 (1988); Boston Gas Company, D.P.U. 89-180, at 16-17 (1990). Further, the Department determined that it was still appropriate, post decoupling, to permit a gas company to retain incremental revenues from new customers added after the test year in order to preserve the incentive for the company to add new customers, which in the long run should reduce a company's average cost of distribution service. See D.P.U. 10-55, at 45; D.P.U. 09-30, at 98-99.

Thus, consistent with Department precedent, the Department will permit the Company to exclude new customers and their associated distribution revenues in the revenue decoupling mechanism until its next rate case. The Company shall track the usage of new customers consistent with the directives in Investigation into Revenue Decoupling Adjustment Factor Filing Procedures, D.P.U. 14-RDAF-01 at 11 (2014).

4. Revenue Decoupling Adjustments

The Attorney General, DOER, and TEC argue that the Company's C&I customer classes should not be grouped together as one class for the purpose of the application of revenues-per-customer to calculate the revenue decoupling adjustment (Attorney General Brief at 79; DOER Brief at 6; TEC Reply Brief at 5). The Attorney General, DOER and TEC assert that such grouping would inappropriately allocate to high load factor rate classes, a portion of the revenue shortfalls or windfalls created by low load factor classes due to changes in use associated with weather or energy efficiency programs (Attorney General Brief at 80, 82, DOER Brief at 6-7; TEC Reply Brief at 5). Conversely, the Company argues that because the purpose of a revenue decoupling mechanism is to align the interests of a distribution company with its deployment of energy efficiency programs, customer size is a more appropriate criterion than load factor for grouping customer classes in a decoupling mechanism (Company Brief at 9).

The appropriate grouping of C&I customers for purposes of a revenue decoupling mechanism has been addressed by the Department in other gas company decoupling proposals. See D.P.U. 11-01/D.P.U. 11-02, at 115; D.P.U. 10-114, at 24; D.P.U. 10-55, at 41; D.P.U. 09-30, at 90-91. In each of those cases, the Department accepted the company's proposal to group the C&I rate classes into one group and develop one base revenue-per-customer benchmark for that group. D.P.U. 11-01/D.P.U. 11-02, at 115; D.P.U. 10-114, at 24; D.P.U. 10-55, at 41; D.P.U. 09-30, at 90-91. In accepting these proposals, the Department found that potential migration from one C&I rate class to another could cause class-specific revenue-per-customer benchmarks to be unrepresentative of the cost to serve that class. D.P.U. 11-01/D.P.U. 11-02, at 115; D.P.U. 10-114, at 24; D.P.U. 10-55, at 41; D.P.U. 09-30, at 90. Further, the Department determined that such migration between rate classes could provide perverse incentives to a company to promote increased throughput because the target revenue-per-customer will be higher for the larger C&I rate classes. D.P.U. 11-01/D.P.U. 11-02, at 115; D.P.U. 09-30, at 90.

In the instant case, separating the Company's six C&I customer classes into two groups based on load factor would alleviate, but not resolve, the customer migration concerns. As a result, the Company would benefit from a low load factor C&I customer that increases its usage in the off-peak period to such an extent that it becomes a high load factor customer and, consequently, generates additional revenues for the Company.

For these reasons, the Department is not persuaded that grouping C&I customer classes by load factor for the purpose of the application of revenues-per-customer to calculate the revenue decoupling adjustment is appropriate. Consistent with the design of the decoupling mechanisms approved to date for the other gas distribution companies, the Department approves the Company's proposal to aggregate its C&I customer classes into one group and develop one benchmark revenues-per-customer for that group the purpose of application of revenues-per-customer to calculate the revenue decoupling adjustment.

5. Revenue Cap

The Department has determined that a revenue decoupling mechanism must be consistent with our precedent related to rate continuity, fairness, and earnings stability. Investigation into Rate Structures that will Promote Efficient Deployment of Demand Resources, D.P.U. 07-50, at 12 (2007). The Department has found that application of revenue cap in the context of a revenue decoupling mechanism is consistent with this precedent. D.P.U. 11-01/D.P.U. 11-02, at 116.

In the instant case, based on the correlation between gas consumption and temperature, annual revenues for NSTAR Gas could vary widely as a result of year-to-year changes in weather. Without any revenue cap, the Company's customers could be subject to overly large annual revenue decoupling adjustments in rates. If the revenue cap is too low, however, customers could be burdened by revenue decoupling adjustments that have been deferred for recovery until later years. See D.P.U. 11-01/D.P.U. 11-02, at 116-117; Western Massachusetts

Electric Company, D.P.U. 10-70, at 45 (2011); D.P.U. 10-55, at 43; D.P.U. 09-39, at 85-86; D.P.U. 09-30, at 114; New England Gas Company, D.P.U. 08-35, at 221 (2009); Massachusetts Electric Company, D.P.U. 92-78, at 116 (1992); D.P.U. 88-67 (Phase I) at 201.

The Department has previously determined that revenue decoupling adjustments should be large enough to avoid intergenerational inequity and unfairness in rates but capped in order to preserve rate continuity. D.P.U. 11-01/D.P.U. 11-02, at 117; D.P.U. 10-70, at 45; D.P.U. 10-55, at 43; D.P.U. 09-39, at 87. In balancing these concerns, the Department has approved a three percent cap on annual revenue decoupling adjustments for gas companies. D.P.U. 11-01/D.P.U. 11-02, at 117; D.P.U. 10-114, at 26; D.P.U. 10-55, at 43; D.P.U. 09-30, at 116-117. Based on these same considerations, the Department finds that a three percent cap based on the Company's total revenues (i.e., peak or off-peak season revenue from distribution rates, LDAC revenue, and gas commodity revenue) is appropriate. Accordingly, the Department approves the Company's proposed three percent revenue cap.

The Department emphasizes that the revenue cap shall apply to the total revenue decoupling adjustment; no costs recovered through the revenue decoupling adjustment factors may exceed the revenue cap, including the revenue decoupling reconciliation adjustment costs or any deferred amounts from application of the revenue cap in a prior period. Further, the Department finds that the revenue cap shall apply only to under-recoveries. The purpose of the revenue cap is to protect customers from large revenue decoupling adjustments. No such protection is necessary in the event of a decoupling adjustment credit.

Finally, because revenue decoupling adjustments are reconciled from one season to another, the Department finds that it is appropriate to evaluate and monitor changes in the market that could impact our rate structure goals and render a three percent revenue cap inappropriate. Accordingly, the Department will review, reevaluate, and modify the revenue cap, as necessary, during the Company's peak and off-peak revenue decoupling adjustment filings. See D.P.U. 10-55, at 44; D.P.U. 09-30, at 117.

6. Revenue Decoupling Adjustment Filings

NSTAR Gas proposes to submit its proposed revenue decoupling adjustment filings at least 45 days prior to the effective dates of the peak and off-peak revenue decoupling adjustment (Exh. NSTAR-CRG-1, at 22-23). This proposal does not afford the Department sufficient time to review the proposed revenue decoupling adjustment filings. See D.P.U. 10-114, at 32; D.P.U. 10-55, at 53. Accordingly, the Department directs the Company to submit its proposed revenue decoupling adjustment filings at least 90 days prior to the effective dates of the November 1st peak period revenue decoupling adjustment and the May 1st off-peak period revenue decoupling adjustment.

7. Conclusion

With the modifications discussed above, the Department finds that the Company's proposed revenue decoupling mechanism is consistent with the policy framework established in D.P.U. 07-50-A and D.P.U. 07-50-B. The Department finds that the Company's proposed revenue decoupling mechanism appropriately aligns the financial interests of the Company with the efficient deployment of demand resources and it will ensure that the Company is not harmed by decreases in sales associated with an increased use of demand resources. Finally, we find that operation of the Company's proposed revenue decoupling mechanism will result in just and reasonable rates. Accordingly, the Department approves NSTAR Gas' proposed revenue decoupling mechanism, as modified herein.

IV. RATE BASE

A. Overview

The Company's test year rate base was $476,645,146 (Exh. NSTAR-MFF-2, Sch. MFF-27 (August 21, 2015)). To this amount, the Company proposes to add $3,414,137 in rate base adjustment for calendar year 2014[9] for a total proposed rate base of $480,059,282 (Exh. NSTAR-MFF-2, Sch. MFF-27 (August 21, 2015)). The Company's total proposed rate base consists of: (1) $650,528,325[10] in net utility plant in service; (2) $2,336,531 in materials and supplies; (3) $3,916,994 in regulatory assets; (5) $7,536,971 in cash working capital; and (6) negative $184,259,539 in net offsets such as deferred income taxes, and customer deposits and advances (Exh. NSTAR-MFF-2, Sch. MFF-27 (August 21, 2015)).

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[9] The 2014 rate base activity results in the following proposed adjustments to the Company's test year end rate base: (1) an increase of $39,409,687 in net utility plant; (2) an increase of $36,993,258 in accumulated deferred income taxes; (3) an increase of $70,891 in customer deposits; (4) a decrease of $2,523 in materials and supplies; (5) a decrease of $162,326 in cash working capital; (6) a decrease of $67,024 in customer advances; (7) an increase of $1,166,424 in regulatory assets (Exh. NSTAR-MFF-2, Sch. MFF-27 (August 21, 2015)). The 2014 net utility plant in service includes $65,488,338 in utility plant in service, less $24,899,758 in depreciation and amortization reserves (Exh. NSTAR-MFF-2, Schs. MFF-28, MFF-29 (August 21, 2015)). The Company includes non-2014 plant adjustments of negative $764,099 in its 2014 utility plant in service, and negative $387,937 in its 2014 depreciation and amortization reserve totals (see Exh. NSTAR-MFF-2, Schs. MFF-27, MFF-28, MFF-29). NSTAR Gas also includes a non-2014 accumulated deferred income taxes adjustment of $97,402 in its 2014 accumulated deferred income taxes activity total (see Exh. NSTAR-MFF-2, Schs. MFF-27, MFF-30 (August 21, 2015)).

[10] Net utility plant in service includes $1,003,847,479 in utility plant in service less $353,319,154 in depreciation and amortization reserves (Exh. NSTAR-MFF-2, Sch. MFF-27 (August 21, 2015)).

B. Plant Additions

1. Introduction

From January 1, 2005 through December 31, 2013, NSTAR Gas completed $459,534,504 in plant additions and retired $54,466,766 in plant, resulting in an increase in utility plant of $405,067,738 (Exhs. NSTAR-LML-2; DPU-8-7, Att.). The Company's adjusted test year actual plant in service as of December 31, 2013 totaled $939,123,240 (Exh. NSTAR-MFF-2, Sch. MFF-28 (August 21, 2015)).

During the twelve months ending December 31, 2014, the Company placed into service $69,038,516 in plant additions and retired $3,550,178 in plant, resulting in a proposed net increase in utility plant of $65,488,338 (Exhs. NSTAR-MFF-5, WP MFF-28 (August 21, 2015); AG-1-17, Att. Supp. 01). During the course of the proceeding, NSTAR Gas reduced its proposed plant in service by $764,099 (Exhs. DPU-8-17; DPU-19-3). Overall, NSTAR Gas proposes $1,003,847,479 in utility plant in service, less $353,319,154 in accumulated depreciation and amortizations, for a net utility plant in service of $650,528,325 (Exh. NSTAR-MFF-2, Sch. MFF-27 (August 21, 2015)).[11]

NSTAR Gas identified 35,019 total capital projects from 2005 to 2013: (1) 1,558 capital projects with a cost greater than $50,000; and (2) 33,461 capital projects with a cost less than or

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11 During the course of the proceedings, the Company updated its proposed revenue requirement calculation for post-test year rate base items to use actual rate base data for November and December 2014, and to provide project documentation for the 2014 plant in service. Although the Department allowed the Company an opportunity to file these updates when setting the procedural schedule in this case, we noted that the filing of the updates "does not constitute a ruling on the propriety of allowing the updated information in the record." D.P.U. 14-150, Procedural Schedule, Service List and Ground Rules at 3 n.3 (January 29, 2015).

equal to $50,000 (Exhs. NSTAR-LML-1, at 9; DPU-3-2, Att.). For 2014, NSTAR Gas identified 4,115 total capital projects: (1) 203 capital projects with a cost greater than $50,000; and (2) 3,912 projects with a cost less than or equal to $50,000 (Exh. DPU-3-2, Att. (Supp. 1)).

NSTAR Gas classifies its projects into three categories: (1) revenue projects/work orders; (3) non-revenue projects/work orders; and (3) non-discretionary projects/work orders (Exh. NSTAR-LML-1, at 9). Revenue projects are those that will add new customers to the Company's system, such as mains extension projects (Exh. NSTAR-LML-1, at 5). Non-revenue projects replace distribution infrastructure for system-integrity purposes, such as the replacement of leak-prone mains and services (Exh. NSTAR-LML-1, at 5-6). Non-discretionary projects include real estate, facility improvements, customer service, and information technology projects (Exh. NSTAR-LML-1, at 9).

Further, the Company classifies some non-discretionary projects as "parent projects" and "child projects"[12] (Exhs. DPU-13-13, Att. (g) at 3; AG-16-22). A parent project covers many similar projects addressing a specific need on the Company's system (Exh. DPU-13-13, Att. (g) at 3). NSTAR Gas uses parent projects when work spans more than one affiliated company or when the project affects multiple classes of plant (e.g., distribution and land) (Exh. DPU-13-13, Att. (g) at 3). In accordance with the Company's project authorization policy, NSTAR Gas does not individually authorize child projects that fall under parent projects; instead, the parent project authorization is considered final approval of the entire overall project,

[12] A child project also can be a subset of a "program" project that includes work spanning several similar projects addressing a specific aspect of the operating system (Exhs. DPU-13-13, Att. (g) at 3; AG-16-22). Unlike a parent project, NSTAR Gas specifically authorizes each child project under a program project in accordance with the Company's project authorization policy (Exhs. DPU-13-13, Att. (g) at 3; AG-16-22).

including the child project (Exhs. DPU-13-13, Att. (g) at 3; AG-16-22). The Company verifies that cumulative estimates of child projects match the total estimate in the parent project authorization (Exhs. DPU-13-13, Att. (g) at 3; AG-16-22).

From 2005 to 2013, revenue producing plant additions accounted for 255 of the projects with a cost greater than $50,000 and 19,812 of the projects with a cost less than or equal to $50,000 (Exhs. NSTAR-LML-4-B1; NSTAR-LML-4-B2; DPU-3-2, Att.). Non-revenue producing plant additions accounted for 1,220 of the projects with a cost greater than $50,000 and 13,518 of the projects with a cost less than or equal to $50,000 (Exhs. NSTAR-LML-4-A; DPU-3-2, Att.). Non-discretionary plant additions accounted for 83 of the projects with a cost greater than $50,000 and 131 of the projects with a cost less than or equal to $50,000 (Exhs. NSTAR-LML-4-C; DPU-3-2, Att.).

In 2014, revenue producing plant additions accounted for 22 of the projects with a cost greater than $50,000 and 2,601 of the projects with a cost less than or equal to $50,000 (Exhs. DPU-3-2, Att. (Supp. 1); DPU-19-10, Att. (c)). Non-revenue producing plant additions accounted for 169 of the projects with a cost greater than $50,000 and 1,307 of the projects with a cost less than or equal to $50,000 (Exhs. DPU-3-2, Att. (Supp. 1); DPU-19-10, Att. (b)). Non-discretionary plant additions accounted for twelve of the projects with a cost greater than $50,000 and five of the projects with a cost less than or equal to $50,000 (Exhs. DPU-3-2, Att. (Supp. 1); DPU-19-10, Att. (a)).

2. Project Documentation

For projects greater than $50,000, NSTAR Gas provided a list of projects categorized by number and associated authorized pre-construction estimated direct costs, actual direct costs, direct cost variance amount, percentage of actual direct costs compared to authorized, and the total cost of the project (Exhs. NSTAR-LML-1, at 9; NSTAR-LML-4). In addition, for revenue projects, the Company's project list included information regarding return on rate base, pre-construction return on rate base, authorized net estimated direct costs of mains and services, net actual direct costs of mains and services, direct cost variance amount, percentage of actual direct costs compared to authorized, total costs of mains and services, total cost of project, and the post-construction return on rate base (Exhs. NSTAR-LML-1, at 10; NSTAR-LML-4-B1; NSTAR-LML-B2).

The Company's project documentation also may include, depending on the size of the project, variance forms and a purpose and necessity document ("P&N") (Exhs. NSTAR-LML-1, at 16-17; NSTAR-LML-5). NSTAR Gas will prepare a P&N when a project's total estimated costs exceed $100,000, or when its actual direct costs exceed $100,000 (Exhs. NSTAR-LML-1, at 19; AG-16-12). A P&N includes: (1) a project description and objectives; (2) a scope and justification; (3) a financial evaluation; (4) a risk assessment; (5) alternatives considered; (6) a technology assessment (for information system projects, only); (7) a project schedule; (8) project milestones; and (9) an implementation plan (Exh. NSTAR-LML-1, at 16-17).

Regarding project cost variances, the Company requires that project managers submit a supplemental P&N for any project in which the actual direct costs exceed or are expected to exceed the authorized budgeted amount according to specific thresholds (Exh. NSTAR-LML-1, at 17). Specifically, NSTAR Gas requires a supplemental P&N if direct costs exceed or are expected to exceed the authorized level by: (1) $25,000 for projects more than $50,000, but less than or equal to $250,000; (2) $50,000 for projects more than $250,000, but less than or equal to

$500,000; (3) ten percent for projects greater than $500,000; and (4) any project with a variance greater than $1.0 million (Exh. NSTAR-LML-1, at 17-18).

3. Blanket Projects

NSTAR Gas states that it uses blanket authorizations to manage costs for smaller projects with a high volume and lower-dollar value (Exhs. DPU-13-14; DPU-13-15; Tr. 7, at 598). A blanket authorization and associated work project estimate will not typically exceed $100,000 (Tr. 7, at 625). The Company uses the same project authorization process for blanket projects as it does for non-blanket projects (Exh. DPU-8-21; Tr. 7, at 624-626). The Company does not require a specific authorization or a P&N for individual work orders under blanket authorizations, but each project under a blanket authorization is reviewed by gas operations and engineering personnel and the engineers develop project estimates[13] (Tr. 7, at 653). The Company states that every approved work order has its own cost-control process, and actual costs associated with blankets are reviewed and approved (Tr. 7, at 653).

4. Gas System Enhancement Program

Pursuant to G.L. c. 164, § 145, the Department approved a Gas System Enhancement Program ("GSEP") for NSTAR Gas, effective January 1, 2015 (Exh. NSTAR-WJA-1, at 19). NSTAR Gas Company, D.P.U. 14-135 (2015). Under the GSEP, the Company plans to replace 30 miles of eligible leak-prone distribution facilities during the 2015 construction year, gradually

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13 The evidence is not clear regarding whether work project estimates are required for each project completed under a blanket authorization. In particular, the Company states that work project estimates are not required for projects completed through a blanket authorization; nonetheless, most projects completed under a blanket work order have individual work project estimates (Tr. 7, at 635). The Company also states that there is an individual estimate for every job under a blanket authorization (Tr. 7, at 652-653).

increasing this amount to 50 miles a year after five years (Exh. NSTAR-WJA-1, at 20). NSTAR Gas anticipates that it will take 25 years to replace all of its leak-prone infrastructure (Exh. NSTAR-WJA-1, at 20). Prior to approval of its GSEP, the Company had historically replaced approximately 25 miles of leak-prone infrastructure per year (Exh. NSTAR-WJA-1, at 20).

5. Positions of the Parties

a. Attorney General[14]

i. Unit of Property Accounting

The Attorney General argues that the Company's model GSEP tariff requires NSTAR Gas to use the same "unit of property"[15] accounting definition that was used during the test year of its "previous" rate case (Attorney General Brief at 6-7, citing D.P.U. 14-135, at 114). The Attorney General contends that because the Company's GSEP was approved prior to the instant rate case, the first year of the GSEP (i.e., 2015) should use the unit of property accounting applicable to the test year in the Company's previous rate case and the second year of the GSEP (i.e., 2016) should use the accounting criteria from the 2013 test year in this filing (Attorney General Brief at 7). Therefore, to ensure regulatory clarity, the Attorney General requests that the Company document the property accounting criteria used in the current test year, as well as in the test year from its previous rate case (Attorney General Brief at 7).

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[14] On August 17, 2015, the Attorney General filed a motion to strike portions of NSTAR Gas' initial brief, claiming that the Company improperly included new information regarding capital projects after the close of the record. The Company filed a response to the motion to strike on August 28, 2015. The Department did not rely on the disputed information in making our findings in Section VI.B.6, below.

[15] According to the Attorney General, a "unit of property" is the smallest measure of a physical asset that a company will consider as a capital cost (Exh. AG-ARN-1, at 9).

ii. Post-Test Year Plant Additions

The Attorney General asserts that Department precedent allows adjustments for post-test year plant additions only when a company demonstrates that the change is outside the normal "ebb and flow" of such item (Attorney General Brief at 8, citing Exh. AG-DJE-1, at 18-19). According to the Attorney General, the Company seeks to adjust its rate base for all new plant added in 2014 but did not propose any specific post-test year plant additions or identify any plant items as outside the normal ebb and flow of plant growth (Attorney General Brief at 7-8, citing Exh. AG-DJE-1, at 18-19). The Attorney General argues that the Company has not presented convincing evidence for the Department to make such a material change in its test year ratemaking practices or to support such a "wholesale revision" to the Department's rate base standards (Attorney General Brief at 8-9). Therefore, the Attorney General argues that the Department should reject the Company's attempts to include 2014 plant additions in rate base (Attorney General Brief at 9; Attorney General Reply Brief at 5, 6).

In support of her position, the Attorney General relies on the Department's findings in D.P.U. 13-75, where the Department rejected Bay State Gas Company's proposal to adjust rate base for post test year non-revenue producing plant additions because it would "disrupt the balance achieved between costs and revenue requirement using a historical test year" (Attorney General Reply Brief at 6, citing D.P.U. 13-75, at 107). The Attorney General claims that the Company's proposal in this proceeding suffers from the same problem (Attorney General Reply Brief at 6).

Next, the Attorney General argues that the Company determined its revenue requirement based on capital investment, operating revenues, and operating expenses during the 2013 test year, adjusted for known and measurable changes through the rate year ending July 1, 2016 (Attorney General Brief at 6, citing Petition at 2). The Attorney General contends, however, that the GSEP investment period begins January 1, 2015 (Attorney General Brief at 6). Therefore, the Attorney General asserts that the rate year period and the GSEP investment period overlap (Attorney General Brief at 6). The Attorney General asserts that the Company should not be permitted to recover GSEP costs both in base rates (through known and measurable changes to test year rate base) and the GSEP factor (Attorney General Brief at 6). To address this issue, the Attorney General asserts that the Department should reject any proposed rate base adjustments for GSEP-eligible plant (Attorney General Brief at 6).

iii. Project Documentation

The Attorney General defines original project documentation as "contracts, field reports, engineering estimates, progress reports, and the like" (Attorney General Reply Brief at 4). By contrast, the Attorney General claims that the Company provided only summary project documentation with its initial filing (Attorney General Brief at 4, citing Exh. NSTAR-LML-5). According to the Attorney General, original project documentation and summary project documentation are not equivalent for the purpose of a prudence review (Attorney General Reply Brief at 4-5). The Attorney General argues that summary information from a work order management or accounting system does not supplant the Company's obligation to provide original project documentation, and that the Company should produce actual documents from a specific project when requested or warranted (e.g., when there are significant cost variances) (Attorney General Reply Brief at 5, citing Bay State Gas Company, D.P.U. 12-25, at 5 (2012)).

In this regard, the Attorney General contends that the Company's summary project documentation lacks specificity and fails to connect the amount of cost variances with specific cost categories, on a project-by-project basis (Attorney General Brief at 10, citing Exh. AG-ARN-1, at 12-13). Specifically, the Attorney General claims that the summary documentation provided by the Company does not provide sufficient detail for reviewers to determine why a stated variance explanation caused an overrun, the costs of the different elements of the overrun, what corrective action might be taken to avoid such overruns in the future, or how the Company could improve its budgeting process going forward (Attorney General Brief at 10, citing Exh. AG-ARN-1, at 12-13; Attorney General Reply Brief at 5, citing Exh. NSTAR-LML-5). The Attorney General asserts that if a company does not describe the reasons for cost variances, the Department has found that there is no basis to determine whether the additional costs were prudently incurred (Attorney General Brief at 10, citing D.P.U. 12-25, at 83).

The Attorney General performed an analysis of the Company's plant additions and developed a list of projects for which she claims the Company failed to provide sufficient justification for cost variances (Attorney General Brief at 10-11). The Attorney General separates such projects into four categories: (1) projects that lack project cost estimation documents (i.e., "Type A" projects); (2) non-revenue projects that lack supporting documentation for cost variances (positive and negative) greater than 30 percent (i.e., "Type B" projects); (3) non-discretionary projects that lack supporting documentation for cost variances (positive and negative) greater than 30 percent (i.e., "Type C" projects); and (4) HOPCO projects that lack any or sufficient supporting documentation for cost variances (positive and negative) greater than 30 percent (i.e., "Type D" projects)[16] (Attorney General Brief at 10-11, citing Exh. DPU-AG-2-1, Atts.). First, the Attorney General argues that the Department should deny all costs associated with Type A projects because they lack project cost estimation documents (Attorney General Brief at 11, citing D.P.U. 09-30, at 114). In addition, for any Type B through Type D project that lacks supporting documentation for cost variances sufficient to determine the prudence of the overage, the Attorney General argues that Department should deny the amount of the cost variance[17] (Attorney General Brief at 11, citing D.P.U. 12-25, at 83).

Finally, the Attorney General recommends that the Department impose more specific rate case filing requirements regarding capital project documentation (Attorney General Brief at 12). Specifically, the Attorney General argues that when a company seeks to include a project in rate base where the final project cost exceeds the original estimate by 15 percent, the company should be required to provide the specific dollar value tied to each cost element responsible for the variance on a project-by-project basis (Attorney General Brief at 12). The Attorney General recommends that a company be required to provide such information, in an appropriate format, with its initial rate case filing (Attorney General Brief at 12). Finally, the Attorney General recommends that the Department require all exhibits compiling capital projects in a list to be filed in Excel format with the initial rate case filing (Attorney General Brief at 12).

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[16] The Attorney General's arguments regarding HOPCO projects are presented in Section X.C.1.a.iii below.

[17] The Attorney General did not quantify the specific amount of total project costs or cost variances that she recommends the Department deny.

b. Company

i. Unit of Property Accounting

NSTAR Gas asserts that its unit of property accounting has remained unchanged since at least 2005 (Company Brief at 53). Therefore, the Company argues that its practice or procedure for determining whether specific project costs are capitalized or expensed was the same in the test year for this rate case as it was in the test year for its previous rate case (Company Brief at 53). Accordingly, NSTAR Gas contends that the same unit of property accounting will apply to the first and second years of its GSEP and no further documentation is required (Company Brief at 53, citing Exh. AG-16-8, Att. (b) at 32; Tr. 7, at 576-579).

ii. Post-Test Year Plant Additions

Regarding its proposed 2014 plant additions, NSTAR Gas argues that it submitted all necessary project documentation for the Department and intervenors to review its capital additions made as of December 31, 2014 (Company Reply Brief at 44, citing Exh. NSTAR-MFF-1, at 4). Further, NSTAR Gas maintains that this evidence supports the plant additions through December 31, 2104 (Company Brief at 52, citing Exhs. DPU-5-8; NSTAR-WJA-1, at 19-21; NSTAR-MFF-1, at 5, 6, 12, 13; NSTAR-LML-1, at 12; NSTAR-LML-1 Supp., at 1-2; NSTAR-LML-5 Supp.; NSTAR-LML-9 (Supp.)).

According to the Company, inclusion of the 2014 net utility plant additions will produce new distribution rates that most closely replicate the Company's actual cost of service going forward (Company Brief at 10, citing Exh. NSTAR-MFF-1, at 4). Further, NSTAR Gas contends that setting rates on a fully representative cost of service benefits customers because it allows the Company to increase the interval between rate cases (Company Reply Brief at 46). In this regard, NSTAR Gas claims that more frequent rate cases are likely if the Department excludes expenses from the cost of service because they are post-test year (Company Reply Brief at 46). For these reasons, NSTAR Gas asserts that the Department should set rates based on the Company's net utility plant as of December 31, 2014 (Company Reply Brief at 46).

Finally, the Company notes that recovery of costs related to GSEP-eligible leak-prone replacement projects commences, by statute, for projects placed in service after January 1, 2015 (Company Brief at 52, citing G.L. c. 164, § 145). NSTAR Gas asserts that its proposed plant additions through December 31, 2014 will be recovered through base rates established in this proceeding while plant additions in service after January 1, 2015 will be eligible for recovery through its GSEP in the future (Company Brief at 52-53). Therefore, the Company asserts that there is no overlap between its GSEP program and its proposed post-test year rate base additions (Company Brief at 51).

iii. Project Documentation

NSTAR Gas disputes the Attorney General's contention that the Company did not provide original project documentation that is sufficient to sustain a prudence review (Company Reply Brief at 49, citing Attorney General Reply Brief at 5). The Company maintains that it provided significant documentation and detail on its projects from 2005 through 2013 (Company Reply Brief at 49, citing Exh. NSTAR-LML-5). NSTAR Gas asserts that the form and substance of its project documentation differs depending on the type of project, but the documentation is consistent with Department policy (Company Brief at 54).

Further, the Company claims that it produced every piece of documentation that it was asked to produce (Company Reply Brief at 49). NSTAR Gas asserts that the Attorney General offers no specific reference to the precise documentation she claims is lacking (Company Reply Brief at 49). Therefore, NSTAR Gas argues that the Department should reject the Attorney General's claims that the Company inappropriately produced summary project documentation in place of original documentation (Company Reply Brief at 49-50).

The Company does not support the Attorney General's recommendation that the Department impose specific filing requirement for capital projects which would require a company to provide the specific dollar value tied to each cost element responsible for an overage on a project-by-project basis (Company Brief at 71, citing Attorney General Brief at 12). NSTAR Gas contends that the Attorney General's request for documentation to support cost variances, in some instances, is not consistent the Company's project authorization practices, which are aligned with the Department's capital project documentation requirements (Company Brief at 54-55).

The Company asserts that the Department has never denied cost recovery simply because the variance analysis does not take a specific form (Company Brief at 55, n.15). Rather, the Company claims that the Department's review of a variance analysis focuses on whether the documentation meets the threshold of providing a reasonable basis for the cost variances (Company Brief at 55, n.15, citing Bay State Gas Company, D.P.U. 13-75, at 114 (2014); D.P.U. 10-55, at 179-180, 187-188; D.T.E. 03-40, at 68; Massachusetts-American Water Company, D.P.U. 95-118, at 49-55 (1996)).

The Company contends that it relied on the Department's standard for project documentation set forth in D.P.U. 12-25 and produced similar documentation in this proceeding (i.e., work orders, capital authorizations, and closing reports for larger projects; and final cost information for smaller projects) (Company Brief at 57, citing D.P.U. 12-25, at 77-78). In this regard, NSTAR Gas claims that it is not required to maintain the same level of detail or produce the same documentation for every project without regard to the dollar value of the project (Company Brief at 56).

In particular, the Company contends that projects it completed under blanket authorizations do not require the full range of documentation that larger, individual projects require (Company Brief at 56, 60). NSTAR Gas claims that the Department has recognized that blanket authorizations are used throughout the utility industry for smaller, routine projects, and to require budget authorizations and closing reports for projects of this nature may prove unnecessarily burdensome given the relatively lower costs per project involved (Company Brief at 58-59, citing New England Gas Company, D.P.U. 12-37, at 4, n.6; 14, n.12 (2014); Boston Gas Company/Colonial Gas Company, D.P.U. 11-36, at 5, n.6; 18, 25-26 (2014); New England Gas Company, D.P.U. 11-42, at 3, n.4 (2013); Bay State Gas Company, D.P.U. 10-52, at 24-25 (2012)). Nevertheless, NSTAR Gas maintains that it provided extensive documentation for each blanket project including: (1) the project description and justification; (2) work project estimates; (3) engineering specifications and requirements; (4) estimated labor costs; (5) estimated indirect costs; and (6) closing reports detailing actual costs (Company Brief at 59 n.16, citing Exhs. NSTAR-LML-5 & Supp., NSTAR-LML-9 & Supp.; Tr. 7, at 601-602). NSTAR Gas contends that because it has demonstrated that it has policies in place to monitor and contain costs, it should not be required provide additional documentation for projects under blanket authorizations to justify cost recovery[18] (Company Brief at 59).

iv. Documentation for Specific Projects

According to the Company, the four non-HOPCO[19] Type A projects identified by the Attorney General as lacking complete project documentation each cost under $100,000 and were completed under blanket authorizations (Company Brief at 60). Because the Company used blanket authorizations, NSTAR Gas claims that pre-construction estimates were not required for these projects[20] (Company Brief at 62). Therefore, NSTAR Gas asserts that disallowance of the cost of these projects is not justified[21] (Company Brief at 62).

With respect to the 185 Type B non-revenue projects that the Attorney General claims lack supporting documentation for cost variances, the Company contends that it provided some general explanation for the variances for 85 of these projects and 100 projects lack explanation (Company Brief at 64). The Company argues, however, that specific documentation allocating the total variance amount to the specific cost variances for these 185 projects is not required under the Department's capital additions precedent (Company Brief at 63).

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18 The Company states that its blanket authorizations are reviewed monthly by gas operations and engineering personnel (Company Brief at 59, n.16, citing Tr. 7, at 596, 653).

19 See Section X below for a summary of the Company's arguments regarding the projects included in HOPCO's rate base (i.e., Type D and certain Type A projects under the Attorney General's classification system).

20 Moreover, the Company claims that these projects do not require preparation of a project variance analysis on an individual project basis (Company Brief at 61).

21 According to the Company, only one project in this category has incomplete documentation (i.e., project 99857, work order 1227865) (Company Brief at 61).

Specifically, for the 85 projects where it provided a general explanation for the variance, NSTAR Gas disputes the Attorney General's claim that it is also required to allocate the total variance amount to the specific reasons for the variance to show the precise dollar values associated with each element of the cost overrun (Company Brief at 63). According to the Company, the Department has been satisfied in prior cases that the requirements for a variance analysis are met by more general explanations (e.g., a cost overrun was caused by the unexpected presence of ledge or other impediments that delayed digging)[22] (Company Brief at 63, citing D.P.U. 13-75, at 95, 105; D.P.U. 12-25, at 79-80, 82; D.P.U. 10-114, at 85-87; D.P.U. 10-55, at 179-180). The Company argues that its documentation for these projects takes a similar form and the reasons for the total cost variances are clear (Company Brief at 64-65).

The Company argues that, of the remaining 100 Type B projects identified by the Attorney General, only 84 have a positive cost variance (Company Brief at 64). According to the Company, only projects with positive cost variances require a cost variance analysis (Company Brief at 64, citing D.P.U. 13-75, at 113-114; D.P.U. 10-114, at 64, 97; D.P.U. 10-55, at 179-180; D.T.E. 03-40, at 68; D.P.U. 95-118, at 49-55; Tr. 12, at 1030, 1057).

NSTAR Gas asserts that 79 of the 84 Type B projects with variances were performed under a blanket authorization and had total actual costs of less than $200,000[23] (Company Brief

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22 For some of these 85 projects, the general explanation given for the variance was "emergent work" (Company Brief at 64). The Company asserts that "emergent work" is emergency work that needs to be completed on short notice and without a pre-authorization form (Company Brief at 64, citing Tr. 7, at 638-639).

23 As described in Section IV.B.2, above, according to the Company's project authorization policy, the estimated project cost threshold requiring the use of a P&N is $100,000 (Exhs. NSTAR-LML-1, at 19; AG-16-12). The Company states, however, that due to a system conversion to consolidate its operating affiliates onto a common accounting

at 64-65). NSTAR Gas argues that, consistent with Company policy, because these projects used a blanket authorization, they did not require a supplemental authorization including a variance analysis (Company Brief at 64-65, citing Tr. 7, at 598, 625, 627-628, 652).

Of the five remaining Type B projects, that Company explains that the project documentation for each project includes a supplemental P&N (Company Brief at 65, citing Tr. 7, at 574, 607). NSTAR Gas argues that the supplemental P&N functions as a variance analysis because the Company is required to analyze cost differentials to support the supplemental authorization (Company Brief at 65, citing Tr. 7, at 574, 607). Based on these considerations, NSTAR Gas asserts no projects identified by the Attorney General as Type B warrant disallowance (Company Brief at 67).

With respect to the 33 Type C non-discretionary projects the Attorney General states lack supporting documentation for cost variances, the Company asserts that only 18 projects do not have an explanation for the cost variance and, of those, only eight have cost overruns (i.e., final project costs for ten Type C projects were less than originally estimated) (Company Brief at 67).

NSTAR Gas contends that several of the eight Type C projects without an explanation for the variance were child projects associated with an authorized parent project (Company Brief at 67). NSTAR Gas asserts that, pursuant to the Company's project authorization policy, child projects do not require a separate authorization and all cost variances are evaluated at the parent level (Company Brief at 68, citing Exh. AG-16-22). NSTAR Gas contends that the remaining

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platform, the threshold requiring the use of a P&N in 2014 was increased to $200,000 (Exh. DPU-20-6). NSTAR Gas states that it returned to its $100,000 threshold in 2015 after the system conversion was complete (Exh. DPU-20-6).

Type C projects have an associated P&N and, therefore, have proper justification for cost variances (Company Brief at 67-68).

Accordingly, NSTAR Gas argues that for all projects identified by the Attorney General as Type C, it has explained cost variances when necessary under its project authorization policy and is not required to specify cost variances with documentation "showing the dollar value associated with the costs that varied between the actual and estimated costs" as proposed by the Attorney General (Company Brief at 69). Therefore, the Company argues that no projects identified by the Attorney General as Type C warrant disallowance (Company Brief at 69).

v. Response to Attorney General's Recommendations

Regarding project estimates, the Company argues that the bulk of its documentation for projects over $100,000 includes a breakdown of direct cost elements, both pre- and post-construction (Company Brief at 71). Therefore, NSTAR Gas asserts that the Company's current documentation practice is appropriate and the Department should not impose any specific documentary requirements (Company Brief at 71). The Company accepts the Attorney General's recommendation that all exhibits identifying capital projects should be filed in Excel format as part of the initial filing (Company Brief at 71-72).

6. Analysis and Findings

a. Standards of Review

i. Prudent, Used and Useful Standard

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. Western Massachusetts Electric Company, D.P.U. 85-270, at 20 (1986). 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 earn a return. D.P.U. 85-270, at 20, 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. Attorney General v. Department of Public Utilities, 390 Mass. 208, 229 (1983). 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 that were known or reasonably should have been known at the time a decision was made. Boston Gas Company, D.P.U. 93-60, at 24-25 (2003); 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 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.[24] D.P.U. 95-40, at 7; D.P.U. 93-60, at 26; The Berkshire Gas Company, D.P.U. 92-210, at 24 (1993); 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, with respect to revenue producing projects, the Department has stated that:

> In reviewing the investments in [revenue producing projects] 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).

ii. Post-Test Year Standard

The Department does not recognize post-test year additions or retirements to rate base, unless the utility demonstrates that the addition or retirement represents a significant investment that has a substantial effect on its rate base. Boston Gas Company, D.P.U. 96-50-C at 16-18, 20-21 (1997); Boston Gas Company, D.P.U. 96-50 (Phase I) at 15-16 (1996) ; D.P.U. 95-118, at 56, 86; D.P.U. 85-270, at 141 n.21; Massachusetts-American Water Company, D.P.U. 1700, at 5-6 (1984). See also Southbridge Water Supply Company v. Department of Public Utilities, 368 Mass. 300 (1975). As a threshold requirement, a post-test year addition to plant must be known and measurable, as well as in service. Dedham Water Company, D.P.U. 84-32, at 17 (1984); D.P.U. 906, at 7-11.

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[24] 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. 03-40, at 52 n.31, citing The Berkshire Gas Company, D.T.E. 01-56-A at 16 (2002); Fitchburg Gas and Electric Light Company, D.T.E. 99-118, at 7 (2001).

The Department has historically judged the significance of an investment by comparing the size of the addition in relation to rate base and not based on the particular nature of the addition. Western Massachusetts Electric Company, D.P.U. 1300, at 14-15 (1983).

b. Unit of Property Accounting

The Attorney General requests that NSTAR Gas document the criteria the Company used to classify its unit of property accounting of capital costs in the current test year as well as the test year from its previous rate case, in order to provide clarity in the Company's GSEP (Attorney General Brief at 7). Conversely, NSTAR Gas asserts that such documentation is not necessary because its unit of property accounting has not changed from one test year to the other (Company Brief at 53).

A clear understanding of NSTAR Gas' unit of property accounting is necessary because the accounting used in the test year from the Company's previous rate case will apply to its first year of GSEP investment, while the accounting used in the current test year will apply to the second year of its GSEP investment and beyond. D.P.U. 14-135, at 14. NSTAR Gas' budget manual provides a comprehensive explanation of how the Company implements the requirements of the Uniform System of Accounts for Gas Companies ("USOA-Gas"), 220 C.M.R. § 51.00 et seq.[25] (Exh. AG-16-4, Att. (a) at 7-8). The Company's unit of property accounting has not changed since 2005 (Exh. AG-16-8, Att. (b) at 32; Tr. 7, at 576-579).

[25] While the term "unit of property" is not used in the USOA-Gas, the term is analogous the term "retirement units" as defined in the USOA-Gas. Boston Gas Company, D.P.U. 88-67, Phase I at 131-132 (1988); Commonwealth Gas Company, D.P.U. 87-122, at 45 (1987). Pursuant to the USOA-Gas, retirement units represent those items of utility plant that are accounted for upon retirement by crediting the book cost thereof to the utility plant account in which the plant had been booked (USOA-Gas, Definitions).

Therefore, the Company's classification of capital costs in the current test year and the test year from its previous rate case are the same. Accordingly, the Department finds that no further documentation of the Company's unit of property accounting is required.

c. Post-Test Year Plant Additions

The Company proposes to include all of its post-test year plant additions through December 31, 2014 in rate base. NSTAR Gas argues such general inclusion of all post-test year plant additions will result in new distribution rates that most closely replicate the Company's actual cost of service on a going forward basis, and benefit customers because it allows the Company to increase the interval between rate cases (Company Brief at 10, 14-19; Company Reply Brief at 46). Conversely, the Attorney General contends that the Company's proposal is not consistent with the Department's established precedent on post-test year plant additions (Attorney General Brief at 7-9; Attorney General Reply Brief at 5, 6). For the reasons discussed below, the Department will review each of the Company's 2014 capital additions to determine whether the expenditures have been prudently incurred and the resulting plant is used and useful to ratepayers. D.P.U. 85-270, at 20.

It is well established Department precedent that base distribution rate filings are based on an historic test year.[26] D.P.U. 07-50-A at 52-53. The ratemaking process is intended to develop

26 The Department requires that the historic test year represent a twelve-month period that does not overlap with the test year used in a previous rate case (unless there are extraordinary circumstances which render a previous Order confiscatory). Massachusetts Electric Company, D.P.U. 19257, at 12 (1977). The test year is generally the most recent twelve-month period for which financial information exists. Town of Hingham v. Dep't of Telecom. and Energy, 433 Mass. 198 (2001). The Department's strong preference is for a test year based on a calendar year cost of service as opposed to a test year that spans two calendar years (i.e., a "split" test year). Plymouth Water Company, D.P.U. 14-120, at 12, 16 (2015).

a representative revenue requirement to be collected from ratepayers and, absent exigent circumstances, it is not intended to track and recover costs on a dollar-for-dollar basis. D.P.U. 10-70, at 174; D.P.U. 07-50-A at 51. Because of the normal ebb and flow of customers, plant investment, and expenses, it is not possible to capture every element of cost and revenues that could in theory be included in rates. D.P.U. 10-70, at 174; D.T.E. 96-50-C at 15-17; D.P.U. 85-270, at 141 n.21 (1986); Bay State Gas Company, D.P.U. 1122, at 46-49 (1982). It is for this reason that the Department does not typically recognize post-test year rate base additions unless they represent a significant investment that has a substantial effect on rate base. D.P.U. 96-50-C at 16-18, 20-21. Here, however, the Department finds that there are unique circumstances present that persuade us to review the entirety of the Company's 2014 plant investment without regard to the size of the additions in relation to rate base.

In particular, on November 24, 2010, NSTAR Gas and NSTAR Electric Company, along with their parent holding company NSTAR, and Western Massachusetts Electric Company, along with its parent holding company Northeast Utilities (collectively "joint petitioners") sought approval from the Department to merge NSTAR and Northeast Utilities into a consolidated organization under the name Northeast Utilities.[27] On February 15, 2012, the joint petitioners, the Attorney General, and DOER submitted a proposed settlement ("Merger Settlement") to the Department. That same day, the joint petitioners and DOER submitted to the Department a separate proposed settlement ("DOER Settlement").[28]

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27 The merger was reviewed by the Department pursuant to G.L. c. 164, § 96.

28 Pursuant to 220 C.M.R. § 1.10(3), the Department incorporates by reference the Merger Settlement and DOER Settlement filed and approved in D.P.U. 10-170-B.

On April 4, 2012, the Department approved both the Merger Settlement and the DOER Settlement and, consequently, the joint petitioners' proposed merger. D.P.U. 10-170-B at 107-108. In the Order approving the settlements, the Department approved a rate freeze applicable to the Company's base distribution rates until January 1, 2016. D.P.U. 10-170-B, at 36, 39-41. On August 3, 2012, several months after the Department's Order in D.P.U. 10-170-B was issued, the Legislature reinstated the ten-month rate case suspension period prescribed in G.L. c. 164, § 94.[29]

The Company filed the instant base distribution rate case on December 17, 2014. The combination of the rate freeze and the reinstated ten-month suspension period had two important effects on the Company's rate filing. First, the Company was compelled to use a 2013 test year (the first full calendar year following the merger) in order to file for new rates that would be effective in conjunction with the end of the rate freeze on January 1, 2016.[30,31] Second, the new

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29 Specifically, St. 2012, c. 209, An Act Relative to Competitively Priced Electricity in the Commonwealth, amended G.L. c. 25, § 18 to repeal the provision in that statute that prescribed a six-month suspension period for gas and electric base distribution rate proceedings.

30 As discussed in D.P.U. 14-120, at 10-11, there are significant complications associated with the use of a split test year that can call into question the use of such data to establish rates (e.g., test year amounts associated with a split test year will not tie back to amounts included in the Annual Returns and audited financial statements, and split test year limits the Department's ability to review year-to-year changes in expense levels).

31 The Department notes that Company's base distribution rates have remained unchanged since 1991. Prior to the instant case, the Company's most recent base distribution rate proceeding was D.T.E. 05-85. A rate settlement in D.T.E. 05-85 froze rates for NSTAR Gas without making any changes to distribution rates and, accordingly, the Company's distribution rates have remained the same since Commonwealth Gas Company, D.P.U. 91-60 (1991).

rates established in this proceeding will not take effect until 24 months after the end of the test year.[32]

Moreover, during the period of the rate freeze, the Department approved the Company's GSEP. D.P.U. 14-135, at 144. The GSEP affords the Company a new means of cost recovery for the revenue requirement associated with the majority of its capital additions on an accelerated basis, and before the actual capital project work is performed in a given year. D.P.U. 14-135, at 51. However, the Company is not eligible to begin to recover such costs until 2016, following the expiration of the rate freeze. D.P.U. 14-135, at 141-143.

The foregoing factors place NSTAR Gas is in a unique position. As a result of the rate freeze and the ten-month suspension period, the Company faces an atypical 24-month lag between the end of the test year and the start of the rate year. The Company's GSEP does not mitigate the impact of such lag because it does not address capital additions made prior to 2016. The Department notes that no other gas or electric distribution company is subject to these constraints.

The Company proposes to update all aspects of its rate base through 2014 and not just its non-revenue producing capital additions[33] (see e.g., Exhs. NSTAR-MFF-1, at 11-13; 59-60; NSTAR-MFF-2, Schs. 27-32 (April 15, 2015; May 20, 2015; June 15, 2015; August 21, 2015)).

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32 By comparison, for the two rate cases adjudicated since the reinstatement of the ten-month suspension period, D.P.U. 13-90 and D.P.U. 13-75, the interval between the end of the test year and the effective date of new rates was 17 months and 14 months, respectively.

33 In D.P.U. 13-75, Bay State Gas Company proposed to include six months of post-test year non-revenue producing capital additions in rate base. For various reasons, the Department rejected Bay State Gas Company's proposal to update just one element of its rate base. D.P.U. 13-75, at 107.

In addition, the Company proposes to update its revenue requirement to account for 2014 weather-normalized sales volumes, including load growth incremental to the test year revenues (see Exh. AG-4-6 & Atts. (Supp. 1); AG-4-6 (Supp. 2); AG-4-8 & Att. (Supp. 1); Tr. 9, at 825-827). The Department finds that the Company's proposal maintains a sufficient balance between costs and revenue requirement.

Further, we note that during the course of the proceeding, the Company provided project documentation to support its proposed 2014 capital additions (see e.g., Exhs. NSTAR-LML-1 (Supp.); NSTAR-LML-3 & Schs. (Supp.); NSTAR-LML-5 (Supp.)). Although the information was provided four months after the initial filing, the parties were afforded an opportunity to conduct discovery on the project documentation and to cross-examine the Company's witnesses during the evidentiary phase of the proceedings. Therefore, the Department finds no due process concerns associated with the review of the Company's 2014 capital additions.

Finally, the Attorney General asserts that the rate year period and the GSEP investment period overlap and, therefore, to avoid a double recovery these investments, the Department should not allow the Company to make any proposed rate base adjustments for GSEP-eligible plant (Attorney General Brief at 6). Pursuant to G.L. c. 164, § 145, recovery of costs related to GSEP-eligible leak-prone replacement projects is for plant placed in service on and after January 1, 2015. Plant additions through December 31, 2014 will be recovered through the base rates established this proceeding. Therefore, the Department finds that there is no overlap between the costs eligible for recovery through the Company's GSEP program and the base rates established in this proceeding (see Exh. MFF-2, Sch. MFF-28 (August 21, 2014)).

Based on the foregoing considerations and the specific facts of this case, the Department finds that it is appropriate to consider for inclusion in rate base the Company's 2014 capital additions. Together with the implementation of its GSEP, we fully expect that our consideration of the 2014 plant additions will allow the Company to increase the interval between rate cases. Finally, we stress that we do not intend for our decision today to represent a wholesale shift in the Department's standard of review for post-test year plant additions and the required showing of significance. Rather, it is a recognition of the unique circumstances present in this case. In the sections below, the Department addresses NSTAR Gas' individual 2014 plant additions based on the prudent, used and useful standard.

d. Attorney General Recommendations Regarding Project Documentation

The Attorney General makes three recommendations regarding capital project documentation on a going forward basis. First, the Attorney General requests that the Department impose specific filing requirements for capital projects such that where a company seeks to collect a cost variance of 15 percent or more, the company would be required to provide the specific dollar value tied to each cost element responsible for the variance on a project-by-project basis (Attorney General Brief at 12).

A company is required to provide a reasonable explanation for cost variances, based on the specifics of each project, sufficient for the Department evaluate the reasonableness and prudence of any cost variance. D.P.U. 12-25, at 79-80, 82; D.P.U. 13-75, at 95, 105; D.P.U. 10-55, at 179-180; D.P.U. 10-114, at 85-87). As described above, if a company adequately justifies the reasons for any cost variance, the Department will consider the costs of the project eligible for inclusion in rate base. If, however, a company is unable to justify the reasons for a cost variance, the Department will exclude the excess costs to the extent that the Company has not met its burden of proof. D.P.U. 13-75, at 114; D.T.E. 03-40, at 68; D.P.U. 95-118, at 49-55.

To the extent that a company is able to document what percentage of a total variance is attributable to each reason given for the variance, it could aid the company in demonstrating prudence. The Department finds, however, that requiring a company to provide such documentation in an initial filing as a matter of routine would not be an efficient use of the company's resources. Accordingly, the Department will not adopt the Attorney General's recommendation regarding the documentation of the dollar value tied to each element responsible for a variance of as a filing requirement. Nonetheless, we remind companies that they bear the burden to demonstrate the reasonableness of all variances and, to the extent information regarding the dollar value attributable to each cause of a variance is necessary to determine prudence based on the facts of a particular case, they must be prepared to provide such information or risk disallowance of the costs.[34]

The Attorney General also requests that a company be required to produce actual documents from a specific capital project (e.g., contracts, field reports, engineering estimates, progress reports, etc.), as opposed to summary documentation, when requested (Attorney General Reply Brief at 5). The Department and intervenors may inquire into any capital project regardless of its final cost. D.P.U. 10-55, at 188. The discovery process provides

[34] As discussed in Section IV.B.6.e.iii below, the documents required to support a variance analysis may take different forms depending on the size and nature of the project but, in all instances, the reasons for the cost variances must be clear. Given the facts of a particular project, an identification of the specific dollar value attributable to each reason for a variance could be required to demonstrate prudence.

the Department and intervenors with the opportunity to request specific invoices or other detailed documentation associated with each capital project.

Finally, the Attorney General recommends that the Department require all company exhibits compiling capital projects in a list to be filed in Excel format with the initial filing (Attorney General Brief at 12). The Department finds that this recommendation is reasonable and will facilitate the review of rate base. Therefore, as part of the initial rate filing, the Department directs all gas and electric companies to provide all exhibits compiling capital projects in a list in Microsoft Excel format with all formulas and cell references intact.

As discussed in n.36 below, the Department directs the Company to provide all of its capital project documents in text searchable format. Finally, as discussed in Section IV.B.6.e.111 below, the Department will require the Company to provide documentation for parent projects for the associated child projects it is proposing to include in rate base with all of its capital project documentation.

e. Plant Additions

i. Introduction

As described in Section IV.B.2 above, NSTAR Gas follows a project authorization policy to manage its capital projects (Exh. NSTAR-LML-1, at 12-13). Pursuant to the Company's project authorization policy, a P&N is used to authorize projects with total estimated costs in excess of $100,000. A P&N is also prepared when actual direct costs exceed $100,000[35]

[35] These thresholds do not include indirect costs associated with a capital project. NSTAR Gas allocates indirect costs to capital projects based on the direct cost categories charged to each capital project (Tr. 7, at 614; RR-DPU-13, Att.). The Company budgets and authorizes indirect costs separately because they are centralized costs that are not directly controlled by individual project managers (Exhs. NSTAR-LML-1, at 17-18; AG-16-9).

(Exhs. NSTAR-LML-1, at 16-19; AG-16-12; Tr. 7, at 624-625). As discussed in n.23 above, the threshold requiring the use of a P&N was increased temporarily to $200,000 in 2014 (Exh. DPU-20-6). If a project's actual direct costs exceed or are projected to exceed the authorized budgeted amount by predetermined thresholds, the Company prepares a supplemental P&N to explain the changes that have or will affect the cost of the project (Exhs. NSTAR-LML-1, at 17; AG-16-9).

Additionally, NSTAR Gas uses a blanket authorization process for certain projects (Tr. 7, at 627). NSTAR Gas applies a $100,000 estimated total cost threshold for blanket projects (Tr. 7, at 627). As discussed in n.23 above, the threshold for blanket authorizations increased temporarily to $200,000 in 2014 (Exh. DPU-20-6). Under a blanket authorization (e.g., services replacements), the Company will create individual work orders for each job (Tr. 7, at 627). NSTAR Gas monitors costs at the work order level under blanket authorizations (Tr. 7, at 627). If a specific work order under the blanket authorization exceeds the $100,000 (or $200,000 for 2014) actual direct cost threshold, the Company will create a P&N document for the work order (Tr. 7, at 628; 654).

NSTAR Gas provides documentation for work orders under blanket authorizations, including work project estimates and closing reports detailing actual costs (Exh. NSTAR-LML-5; Tr. 7, at 653). To control costs for blanket projects, the Company's gas and engineering personnel monitor blanket authorizations on a monthly basis through the Company's work management system. NSTAR Gas personnel also review and approve the costs for each work order (i.e., timesheets, invoices, and material requisitions) (Tr. 7, at 653). The

Company does not, however, provide documentation explaining cost variances for blanket projects with actual direct costs less than $100,000 (or $200,000 for 2014) (Tr. 7, at 596, 653).

Blanket authorizations are a common feature of utility business and are used for smaller, low-cost capital projects that are of a routine, recurring nature. D.P.U. 10-52, at 14; D.P.U. 09-39, at 93 n.79; Fitchburg Gas and Electric Light Company, D.T.E. 02-24/25, at 41-43 (2002); Massachusetts Electric Company, D.P.U. 95-40, at 4 (1995). To require documents such as variance reports for projects of this nature could prove unnecessarily burdensome given the relatively low cost per project involved. See Fitchburg Gas and Electric Light Company, D.P.U. 13-90, at 55 n.38 (2014); D.P.U. 10-52, at 24;. Accordingly, the Department has allowed the use of blanket authorizations to support the inclusion of smaller, more routine projects in rate base if a company demonstrates that it has sufficient policies in place designed to monitor and contain costs. D.P.U. 10-52, at 24; D.P.U. 12-25, at 62.

In the instant proceeding, the Department has concerns about the Company's use of blanket authorizations. In particular, the Department is concerned about the high percentage of projects that the Company completes under blanket authorizations each year (see Exhs. NSTAR-LML-5 & Supp.; NSTAR-LML-9 & Supp.; Tr. 7, at 601-602). Specifically, from 2005 to 2014, the Company completed approximately 98 percent of all capital projects through work orders under blanket authorizations (Exh. DPU-3-2, Att. & (Supp. 1)). For capital projects with total costs exceeding $50,000, NSTAR Gas completed between 50 and 80 percent of such projects each year under blanket authorizations (Exh. DPU-3-2, Att. & (Supp. 1)).

Variance and blanket authorization thresholds used by the Company in the capital authorization process do not mean that projects of a lower value are exempt from scrutiny or the requirement that a company maintain adequate documentation to support the prudence of these capital additions. Given that NSTAR Gas currently prepares a lower level of documentation to support the inclusion of blanket projects in rate base, we find that the Company's $100,000 threshold for blanket authorizations is at a level that impairs our ability to conduct an efficient and thorough prudence review.[36] Work orders under blanket authorizations with total costs above $50,000 and below $100,000 (or $200,000 in 2014) are not "smaller" or "low-cost" projects for the purpose of a prudence review.[37] The Department finds that such projects are of a sufficient size as to warrant more explicit cost variance analysis.[38]

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36 In order to review capital project documentation and understand the Company's complex capital project authorization process and blanket authorization policy, the Department was required to issue several rounds of discovery (see Exhs. DPU-3-1; DPU-3-5; DPU-8-22; DPU-13-14; DPU-13-15; DPU-17-2; DPU-19-8, DPU-19-9; DPU-19-10). In addition, a significant amount of time during evidentiary hearings was devoted to exploring the various components and terminology of the Company's capital authorization policy (Tr. 7). Going forward, the Department directs the Company to provide all of its capital project documents in text searchable format. Moreover, the Department directs the Company to use consistent terminology, to the extent possible, when referring to the same concept (e.g., blanket authorization versus a line of business authorization or a pre-construction estimate versus a work project estimate) (see Tr. 7, at 625, 573; Company Brief at 41).

37 Liberty Utilities (f/k/a New England Gas Company) uses a $50,000 cost threshold for blanket authorizations. D.P.U. 11-42, at 3, n.4; D.P.U. 10-114, at 81, n.67. Fitchburg Gas and Electric Light Company d/b/a Unitil sets its threshold for blanket projects at $20,000. D.P.U. 13-90, at 55.

38 The Company's own cost variance policy requires a supplemental P&N if direct costs exceed the authorized level by $25,000 for projects more than $50,000, but less than or equal to $250,000 (Exh. NSTAR-LML-1, at 17-18). Blanket projects may fall under this category, yet the Company does not prepare supplemental documentation describing the reasons for cost variances for blanket projects with actual direct costs between $50,000 and $100,000 (Exhs. DPU-13-14; NSTAR-LML-5, 2010, Non-Revenue, 99817 WO 1726460).

NSTAR Gas 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 the event of a cost variance. D.T.E. 03-40, at 68. In the instant case, in consideration of the policies that the Company has in place to monitor and control costs, the Department will review the capital project documentation and closing reports for all work orders completed under blanket authorizations to determine whether the expenditures are prudently incurred (Exh. NSTAR-LML-1, at 18-19; Tr. 7, at 653). Going forward, NSTAR Gas shall document cost variances and provide variance analyses on all projects (completed under blanket authorizations or not) with actual direct costs in excess of $50,000 with a direct cost variance greater than the predetermined variance thresholds contained in its current capital authorization policy.[39,40] As part of its next base distribution rate case or HOPCO rate proceeding (whichever comes first), the Company shall clearly document the processes and procedures it has implemented to document cost variances for projects actual direct costs in excess of $50,000.[41] At that time, the Department will review the blanket authorization policy predetermined variance

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[39] Pursuant to the Company's current capital authorization policy, a variance analysis is required where direct costs exceed or are expected to exceed the authorized level by: (1) $25,000 for projects more than $50,000, but less than or equal to $250,000; (2) $50,000 for projects more than $250,000, but less than or equal to $500,000; (3) ten percent for projects greater than $500,000; and (4) any project with a variance greater than $1.0 million (Exh. NSTAR-LML-1, at 17-18).

[40] Nothing in this Order shall change the information the Company is required to provide with respect to deviations from budgeted costs within its GSEP program. See D.P.U. 14-135, at 125, 128.

[41] Given the extensive documentation already provided by the Company for these projects, such as detailed work project estimates and closing reports, it should not be overly burdensome for the Company to describe cost variances for projects that incur actual direct costs above $50,000.

thresholds to consider whether any changes are warranted to improve the Department's ability to conduct an efficient and thorough prudence review.

For 2014, as discussed above, with few exceptions, NSTAR Gas did not develop P&Ns for individual projects with estimated total costs below $200,000[42] (Exh. DPU-20-6). Therefore, the Company provided variance analyses for projects only at or above $200,000 where the cost variances met the Company's predetermined thresholds for additional analysis (Exh. DPU-20-5; DPU-20-6). Project managers were responsible for managing the process to control costs and periodically reported to supervisors on project costs and progress (Exh. DPU-20-6). The Department is not persuaded that the Company's reliance on project managers alone to periodically report on project costs provides sufficient cost control, especially for larger projects with costs between $100,000 and $200,000. Projects of this magnitude are not smaller, routine, or low-cost projects that require less cost oversight. Other than explaining that this shift in threshold was temporary and related to a system conversion to consolidate its operating companies onto a common accounting platform, we find that the Company has failed to justify that a variance analysis threshold of $200,000 is reasonable (Exhs. DPU-20-6; DPU-20-6).

In consideration of these findings, in Section IV.B.6.f.ii, below, the Department will evaluate the prudence of 2014 projects with total costs between $100,000 and $200,000. For 2014 projects, the Department relied on total project costs (versus direct project costs) in evaluating cost variances that met the Company's predetermined variance thresholds.

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42 For example, NSTAR Gas provided a P&N for project 14808 (total costs of $187,067) but did not provide a P&N for project 99814, work order 1979150 (total costs of $131,457) (Exhs. NSTAR-LML-5 (Supp.) Non-Revenue, 14808; NSTAR-LML-5 (Supp.) Non-Revenue, 99814 WO 1979150).

ii. 2005-2013 Capital Projects $50,000 and Below

As of the end of the test year, the Company completed 33,461 projects with budgets of $50,000 or less (Exh. DPU-3-2, Att.). The Department has recognized the value of a project cost threshold[43] in the discovery process as a reasonable way to balance the need for effective regulatory review of the Company's capital projects and the impracticability of routinely devoting considerable resources to the examination of variances in relatively low-cost projects. D.P.U. 12-25, at 77; D.T.E. 05-27, at 76.

The Department finds that a project cost document production threshold of $50,000 is appropriate for a company the size of NSTAR Gas. See D.P.U. 11-42, at 3, n.4; D.P.U. 10-114, at 81, n.67. Nevertheless, document production thresholds used by the Department in the discovery process do not mean that projects of a lower value are exempt from scrutiny or the requirement that a company maintain adequate documentation to support the prudence of these capital additions. Rather, the Department and intervenors may inquire into any project regardless of its final cost. D.P.U. 12-25, at 77; D.P.U. 10-55, at 188.

No party challenged the inclusion of the 33,461 capital projects with budgets of $50,000 or less in rate base. The Department has reviewed the information provided by the Company for these projects and finds that the project costs were prudently incurred and the projects are used and useful in service to customers (Exhs. NSTAR-LML-3, Schs. 2005-2013, C-1; C-2; C-3; D-1;

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43 Under a project cost document production threshold, a company identifies the cost of projects but does not provide further documentary support for projects with a total cost less than the threshold, unless requested through discovery or cross examination. Conversely, a company should provide complete documentary support for projects exceeding the threshold in the initial filing.

D-2; D-3; DPU-3-2, Att.). Accordingly, the Department allows the cost of these projects to be included in rate base.

iii. 2005-2013 Capital Projects over $50,000

(A) Overview

From January 1, 2005 to December 31, 2013, the Company completed 1,558 projects with total costs in excess of $50,000[44] (Exhs. NSTAR-LML-4-A; NSTAR-LML-4-B1; NSTAR-LML-B2; NSTAR-LML-C; DPU-3-2, Att.). Of the 1,558 projects, 644 were at or under budget and 748 exceeded budgets by an amount not large enough to trigger a variance analysis under the Company's capital authorization policy[45] (see Exhs. NSTAR-LML-4-A; NSTAR-LML-4-B-1; NSTAR-LML-4-B-2; NSTAR-LML-4-B-C). The 166 remaining projects exceeded the authorized budgeted amount by predetermined thresholds[46] (Exh. NSTAR-LML-1, at 17-18).

44 Of these 1,558 projects, the Attorney General contests five Type A projects, 48 Type B projects, and 32 Type C projects. These contested projects are discussed in Section IV.B.6.e.iii, below (see Exh. DPU-AG-2-1, Att.). Two of these Type A projects are also Type B projects (i.e., the Attorney General contested two projects for two reasons). Therefore, in total, the Attorney General contests 83 of the 1,558 capital projects over $50,000 (Exh. DPU-AG-2-1).

45 Of the 644 projects identified as at or under budget, 83 lacked project costs estimates because they were emergent work projects. In addition, 149 projects for services relays lacked project cost estimates because the pre-construction estimates were developed for the associated mains relay project (Exh. NSTAR-LML-4-A).

46 As discussed in Section IV.B.2 above, the thresholds are: (1) $25,000 for projects more than $50,000, but less than or equal to $250,000; (2) $50,000 for projects more than $250,000, but less than or equal to $500,000; (3) ten percent for projects greater than $500,000; and (4) any project with a variance greater than $1.0 million (Exh. NSTAR-LML-1, at 17-18).

Of the 1,392 projects that were at or under budget or below the variance threshold, 49 projects were challenged by the Attorney General and are discussed in Section IV.B.6.e.iii below.[47] Accordingly, 1,343 unchallenged projects are at or under budget or below the variance analysis threshold.

Of these unchallenged projects, the Department has examined the documentation provided by the Company for the 625 projects that are at or under budget, including work orders, capital authorization, and closing reports (Exh. NSTAR-LML-5). Based on our review of the documents, the Department finds that the costs for these projects were prudently incurred and that the capital investments are used and useful in service for customers. Accordingly, the Department will include the cost of these 625 uncontested projects in rate base.

The Department has also examined the documents provided by the Company for the 718 uncontested projects that were over budget but below the Company's variance analysis threshold, including work orders, capital authorization, and closing reports (Exh. NSTAR-LML-5). Together with the process the Company has in place to monitor and control costs, the Department finds that the Company has supported the prudence of the proposed projects and variances. Based on our review, Department finds that the project costs were prudently incurred and the projects are used and useful in service to customers. Accordingly, the Department will include the cost of these 718 uncontested projects in rate base.

For the remaining 132 uncontested projects exceeding the authorized budgeted amount, NSTAR Gas' capital authorization policy provides that supplemental authorizations must be prepared if direct spending exceeds the authorized level by the threshold amounts

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[47] Of the 49 projects challenged by the Attorney General, 19 projects are at or under budget and 30 projects are below the variance threshold (Exh. DPU-AG-2-1, Att.).

(Exh. NSTAR-LML-1, at 17-18). The Company removed one such project from rate base due to a lack of sufficient documentation (Exh. NSTAR-LML-5, 2005, Revenue, ROR, project 01845). The Company provided variance reports or explained cost variances for 95 of the remaining 131 uncontested projects (Exhs. NSTAR-LML-4-A; NSTAR-LML-4-B-1; NSTAR-LML-4-B-2; NSTAR-LML-4-B-C; NSTAR-LML-5; DPU-8-17; DPU-13-18; DPU-13-19; DPU-13-21; DPU-13-22; DPU-13-23; NSTAR-LML-5, 2005, Revenue, ROR, project 01845; Tr. 7, at 628-630, 632).

The variance reports include original and updated budgets, project descriptions, a breakdown of the change in cost elements, and short summaries of the reasons for budget variances (see, e.g., Exhs. NSTAR-LML-5, 2013, Non-Revenue, 13868; NSTAR-LML-5, 2009, Non-Revenue, 08851; NSTAR-LML-5, 2011, Non-Discretionary, 10708; NSTAR-LML-5, 2009, Non-Revenue, 09808). The variance reports indicate that the most common causes for a budget variance were: (1) ledge or other impediments that delayed digging; (2) municipal requirements; (3) environmental restrictions; and (4) work in high volume traffic areas (see, e.g., Exhs. NSTAR-LML-5, 2013, Non-Revenue, 13868; NSTAR-LML-5, 2009, Non-Revenue, 08851; NSTAR-LML-5, 2011, Non-Discretionary, 10708; NSTAR-LML-5, 2009, Non-Revenue, 09808).

The Department finds that the level of documentation provided by the Company adequately supports our review of the prudence of the proposed projects and variances. Based on our review, Department finds that the project costs were prudently incurred and the projects are used and useful in service to customers. In addition, the Department finds that the explanations for cost variances were reasonable, and the variances were outside of the

Company's control and consistent with the actions of a utility incurring additional cost in a prudent manner. Accordingly, the Department will include the costs of these 95 uncontested projects in rate base.

The Company did not provide variance reports for the remaining 36 uncontested projects for reasons including the timing of cost reversals or because the total actual cost variances met the predetermined variance thresholds but the projects' actual direct costs were less than $100,000 (i.e., blanket projects)[48] (see Exhs. NSTAR-LML-4-A; NSTAR-LML-4-B-1; NSTAR-LML-4-B-2; NSTAR-LML-4-C). The Department has examined the documents provided by the Company for these 36 uncontested projects, including work orders, capital authorization, and closing reports (see, e.g., Exhs. DPU-13-8; NSTAR-LML-5, 2013, Non-Revenue, 99971 WO 1926379). Together with the process the Company has in place to monitor and control costs, the Department finds that the Company has supported the prudence of the proposed projects and variances. Based on our review, Department finds that the project costs were prudently incurred and the projects are used and useful in service to customers. Accordingly, the Department will include the cost of these 36 uncontested projects in rate base.

In total, the Department approved 1,474 uncontested capital projects completed by the Company as of the end of the test year. In the sections below, the Department addresses the 83 remaining projects completed by the Company as of the end of the test year with total costs in

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48 The Company will accrue incurred costs that have not yet been billed each month (Exh. DPU-13-8). The accruals are recorded in the current month and reversed the following month as NSTAR Gas bills the costs (Exh. DPU-13-8). For some projects with costs recorded at the end of 2013, the costs are incurred in November 2013 and are reversed in the accounting system by December 2013 (Exh. DPU-13-8). NSTAR Gas did not record the reversal in the plant system until January 2014 (e.g., project 13896) (Exh. DPU-13-8).

excess of $50,000. As discussed above, the Attorney General requests that the Department deny all or a portion of the costs of these projects because they lack sufficient cost estimation documents (i.e., Type A projects) or insufficient support for variances (i.e., Type B and Type C projects) (Attorney General Brief at 11, citing D.P.U. 12-25, at 83; D.P.U. 09-30, at 114; see also Exh. DPU-AG-2-1, Att.).

(B) Type A Projects

The Attorney General claims that five projects lack supporting documentation for cost estimates (Attorney General Brief at 10-11, citing Exh. DPU-AG-2-1, Att.). In particular, the Attorney General asserts the Company did not produce any estimation documentation or the documentation provided was incomplete (Exh. DPU-AG-2-1, Att.). The Attorney General claims that because these projects lack estimates and proper documentation, the total cost of the projects should be denied (Attorney General Brief at 11). Because these projects were completed under blanket authorizations, the Company asserts that pre-construction estimates were not required and the projects do not require the preparation of a supplemental authorization for cost variance on an individual project basis[49] (Company Brief at 61-62). All five contested projects are blanket projects and identified by either project number 99806 or 99857 (Exh. DPU-AG-2-1, Att.).

Under project 99806, the Company completed two work orders (i.e., 1880432 and 1942483) and closed to plant total costs of $97,561 and $51,703, respectively (Exhs. DPU-AG-2-1, Att.; NSTAR-LML-3, Sch. 2013-B-1, at 1-2; NSTAR-LML-5, 2013,

[49] As discussed n. 13 above, the record contains conflicting evidence as to whether blanket projects required pre-construction estimates under the Company's capital project authorization policy.

Non-Revenue, 99806 WO 1880432; NSTAR-LML-5, 2013, Non-Revenue, 99806 WO 1942483). For work order 1880432, NSTAR Gas closed to plant $55,188 in direct costs, exceeding the authorized direct costs by $15,188 (Exhs. NSTAR-LML-5, 2013, Non-Revenue, 99806 WO 1880432, at 1; NSTAR-LML-3, Sch. 2013-B-1, at 1). For work order 1942483, the Company closed to plant $26,190 of direct costs, exceeding the authorized direct costs by $6,190 (Exhs. NSTAR-LML-5, 2013, Non-Revenue, 99806 WO 1880432, at 1; NSTAR-LML-3, Sch. 2013-B-1).

For these two work orders, the Company used a vendor quote as a project cost estimate and did not provide any further documents to support the estimate (Tr. 7, at 640-641). Because these projects were not estimated to incur total costs in excess of $100,000 and did not incur direct costs greater than $100,000, the Company did not complete an analysis on the cost variances (Exhs. NSTAR-LML-5, 2013, Non-Revenue, 99806 WO 1880432; NSTAR-LML-5, 2013, Non-Revenue, 99806 WO 1942483).

The Department reviewed the documentation provided by the Company associated with the two non-revenue producing blanket projects under project 99806 including the Company's yearly additions reports and closing reports (Exhs. NSTAR-LML-5, 2013, Non-Revenue, 99806 WO 1880432; NSTAR-LML-5, 2013, Non-Revenue, 99806 WO 1942483). For each project, the Company provided the level of data specified under its current capital authorization policy to support its initial cost estimates and variances[50] (Exh. DPU-13-13, Atts.). Together with the process the Company has in place to monitor and control costs, the Department finds that the costs of the two capital projects completed under project number 99806, including the project

50 As discussed in Section IV.B.6.e.i above, the Company will be required to provide additional documentation to support project cost variances.

variances, were prudently incurred. Further, we find that the Company has demonstrated that each project is used and useful in service to customers. Accordingly, the Department will include the costs of these projects in rate base.

Under project 99857, the Company completed three work orders (i.e., 1261447, 1270184, and 1227865) and closed to plant total costs of $52,324, $59,954, and $126,172, respectively (Exhs. NSTAR-LML-5, 2006, Revenue, ROR, 99857 WO 1261447, at 1; NSTAR-LML-5, 2005, Revenue, ROR, 99857 WO 1270184, at 1; NSTAR-LML-5, 2005, Revenue, ROR, 99857 WO 1227865, at 1; DPU-8-13, Atts. (a), (b)). These work orders all incurred direct costs less than $100,000 and, therefore, the Company did not perform a pre-construction project authorization or variance analysis under the Company's current project authorization policy. The Company's project authorization policy, however, requires that all work orders under blanket authorizations contain an individual cost estimate (Tr. 7, at 653).

Each of these three projects is a revenue project for new business mains (Exhs. NSTAR-LML-5, 2006, Revenue, ROR, 99857 WO 1261447, at 1; NSTAR-LML-5, 2005, Revenue, ROR, 99857 WO 1270184, at 1; NSTAR-LML-5, 2005, Revenue, ROR, 99857 WO 1227865, at 1; DPU-8-13, Atts. (a), (b))). For revenue producing projects (e.g., mains extensions), a company is expected demonstrate that it was prudent to embark on the project. The Berkshire Gas Company, D.P.U. 92-210, at 21-24 (1993). The Department has determined that such evaluation will likely consists of cost-benefit analyses (particularly for plant such as mains extensions) and could take into consideration anticipated growth opportunities identified by the utility in its decision-making process. D.P.U. 92-210, at 21-24. The Company is required to make such showing for all revenue producing projects regardless of size. D.P.U. 92-210, at 24.

The Company did not provide cost estimates for the three mains extensions under project 99857 and, consequently, did not perform a pre- and post-construction return or cost-benefit analyses. Therefore, the Department finds that the Company failed to demonstrate the prudence of project 99857, work orders 1227865, 1261447, and 1270184. Accordingly, the Department reduces the Company's plant in service by $238,450.

(C) Type B/Non-Revenue Projects

The Attorney General asserts that 48 non-revenue projects completed by the Company as of the end of the test year lack supporting documentation for cost variances greater than 30 percent (i.e., Type B) (Attorney General Brief at 10-11, citing Exh. DPU-AG-2-1, Att.). Of the 48 projects, seven had negative cost variances (i.e., the projects were under budget) and, accordingly, the Department need not address the prudence of such variances (see Exh. DPU-AG-2-1, Att.). See D.P.U. 96-50 (Phase I) at 23. The Department has reviewed the information provided by the Company for these seven projects and finds that the project costs were prudently incurred and the projects are used and useful in service to customers (see Exhs. NSTAR-LML-4-A; NSTAR-LML-5; DPU-AG-2-1, Att.). Accordingly, the Department will include the costs of these seven projects in rate base.

The remaining 41 projects had cost overruns greater than 30 percent, with variances ranging from 30 percent to 469 percent (Exh. DPU-AG-2-1, Att.). Blanket authorizations were used for 27 of these projects (see Exh. DPU-AG-2-1, Att.).

The Department has reviewed the total project costs, including overruns, for the blanket projects. All but one of these projects had estimated total costs less than $100,000 and actual direct costs of less than $100,000 (see Exhs. NSTAR-LML-4-A; DPU-AG-2-1, Att.). Pursuant to the Company's current project authorization policy, these 26 projects did not require a supplemental explanation or authorization for the variances (see Exhs. NSTAR-LML-1, at 17-19; AG-16-12). However, the Company provided estimated costs, actual costs, and closing reports for each project (see Exhs. NSTAR-LML-4, NSTAR-LML-4-A).

Together with the process the Company has in place to monitor and control costs, the Department finds that the costs of the 26 capital projects, including the project variances, were prudently incurred (see Exhs. NSTAR-LML-4-A; NSTAR-LML-5; DPU-AG-2-1, Att.). Further, we find that the Company has demonstrated that each project is used and useful in service to customers. Accordingly, the Department will include the costs of these 26 projects in rate base.

One blanket project (i.e., project 99897, work orders 1696794 and 1696799) had actual direct costs of $636,769 and a direct cost variance of $455,671 (Exhs. NSTAR-LML-5, 2013, Non-Revenue, 99897 WO 1696794, 1696799, at 1; NSTAR-LML-3, Sch. 2013-B-1, at 6). Pursuant to the Company's current project authorization policy, this project required a supplemental explanation or authorization for the variance (Exh. NSTAR-LML-1, at 17-18).

This project is classified as a line of business authorization for the Company to replace encoder receiver transmitters ("ERTs") on gas meters. Every year, NSTAR Gas allocates a certain amount of capital dollars to complete ERT projects (Exh. NSTAR-LML-5, 2013, Non-Revenue, 99897 WO 1696794, 1696799, at 3). The Company provided estimated and actual costs, a P&N document, and a closing report for this project; however, the Attorney

General contests it on the basis that, while the Company provided the dollar value of the total variance, it did not itemize the dollar value attributable to each explanation for the variance (Attorney General Brief at 11, citing Exh. DPU-AG-2-1, Att.) (Exh. NSTAR-LML-5, 2013, Non-Revenue, 99897 WO 1696794, 1696799, at 3).

The Company's initial budget estimate included the costs of 200 remote ERTs (Exh. NSTAR-LML-5, 2013, Non-Revenue, 99897 WO 1696794, 1696799, at 3). During the year, the Company purchased an additional 12,050 ERTs due to low inventory[51] (Exh. NSTAR-LML-5, 2013, Non-Revenue, 99897 WO 1696794, 1696799, at 3). Therefore, the Department finds that the Company provided sufficient explanation for the cost variance of this project and, in this instance, a further breakdown of the costs is not required in order for the Department to assess prudence. Based on our review of the Company's documentation, the Department finds that the costs of project 99897, including the variance, were prudently incurred. Further, we find that the Company has demonstrated that the project is used and useful in service to customers. Accordingly, the Department will include the costs of this project in rate base.

The remaining 14 Type B projects had total estimated costs greater than $100,000 and actual direct costs greater than $100,000[52] (Exhs. NSTAR-LML-4-A; DPU-AG-2-1, Att.). The

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[51] The Company estimates that it replaces 31,875 ERTs annually (Exh. NSTAR-LML-5, 2013, Non-Revenue, 99897 WO 1696794, 1696799, at 7).

[52] NSTAR Gas provided documentation for these projects, including work orders, capital authorization, and closing reports (see, e.g., Exh. NSTAR-LML-5, 2013, Non-Revenue, 11860).

Company provided an explanation of the cause(s) of the variance for each project[53] (Exh. DPU-AG-2-1, Att.; see also, Exhs. NSTAR-LML-5, 2013, Non-Revenue, 13808; NSTAR-LML-5, 2013, Non-Revenue, 12873; NSTAR-LML-5, 2013, Non-Revenue, 11860; NSTAR-LML-5, 2013, Non-Revenue, 11856). The Attorney General contests these projects on the basis that, while the Company provided the dollar value of the total variance, it did not itemize the dollar value attributable to each explanation for the variance (Attorney General Brief at 11, citing Exh. DPU-AG-2-1, Att.). With one exception discussed below, the Department finds that the Company has provided sufficient explanation for cost variances and, in these instances, a further breakdown of the costs is not required in order for the Department to assess prudence.

The Department has reviewed documentation for project 13843, work order 1816616 (Exh. NSTAR-LML-5, 2013, Non-Revenue, 13843). The Company argues that this project had direct costs of less than $100,000 (Company Brief at 66). The Department finds, however, that NSTAR Gas closed to plant $136,487 in direct costs and incurred a direct cost variance of $64,584 (Exhs. NSTAR-LML-3, Sch. 2013-A-1, at 5; NSTAR-LML-5, 2013, Non-Revenue, 13843, at 1).

Pursuant to the Company's project authorization policy, any project with direct costs greater than $100,000 requires a P&N document (Exh. NSTAR-LML-1, at 19). Further, the project requires a supplemental authorization if direct spending exceeds the authorized level by

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53 For example, the causes of these variances included: (1) hitting ledge during the project; (2) requiring additional labor, equipment, or police presence; (3) excavation issues; and (4) paving issues (Exh. DPU-AG-2-1, Att.; see also Exhs. NSTAR-LML-5, 2013, Non-Revenue, 13808; NSTAR-LML-5, 2013, Non-Revenue, 12873; NSTAR-LML-5, 2013, Non-Revenue, 11860; NSTAR-LML-5, 2013, Non-Revenue, 11856).

$25,000, for projects with direct costs in excess of $50,000 but less than $250,000 (Exhs. NSTAR-LML-1, at 17-18; DPU-13-14; DPU-13-15).

NSTAR Gas asserts on brief that the cost variance for this project was caused by difficult excavation conditions (Company Brief at 66). Nonetheless, the Company's project documentation does not contain any evidence to support this variance (Exh. NSTAR-LML5, 2013, Non-Revenue, 13843). Therefore, the Department finds that NSTAR Gas failed to provide the appropriate evidence to support the cost variance for project 13843. Accordingly, the Department reduces Company's plant in service by $134,679.[54]

With the exception of the cost variance for project 13843, the Department finds that costs of the non-revenue capital with total estimated costs greater than $100,000 and actual direct costs greater than $100,000, including variances, were prudently incurred. Further, we find that the Company has demonstrated that each project is used and useful in service to customers. Accordingly, the Department will include the costs of these 13 projects in rate base.

(D) Type C/Non-Discretionary Projects

The Attorney General identifies 22 Type C non-discretionary projects that have positive cost variances greater than 30 percent and were closed to plant by the end of the test year[55]

[54] The direct cost variance totaled $64,584 (Exhs. NSTAR-LML-3, Sch. 2013-A-1, at 5; NSTAR-LML-5, 2013, Non-Revenue, 13843, at 1). The Company booked to plant total direct costs of $136,487 (Exh. NSTAR-LML-5, 2013, Non-Revenue, 13843, at 1). The proportion of the direct cost variance to total direct costs is 47 percent. NSTAR Gas booked to plant total indirect costs of $148,134. Thus, 47 percent of indirect costs is $70,095. Therefore, reduction in plant in service of $134,679 is the direct cost variance of $64,584 plus indirect costs of $70,095.

[55] The Attorney General identified ten additional Type C projects in service by the end of the test year that had negative variances greater than 30 percent (Exh. DPU-AG-2-1, Att.). The Department has reviewed the information provided by the Company for these

(Exh. DPU-AG-2-1, Att.). The Attorney General asserts that, to varying degrees, the Company provided insufficient supporting documentation for the variances (Attorney General Brief at 10-11, citing Exh. DPU-AG-2-1, Att.). Of the 22 projects, the Company provided an explanation for the cost variance for 14 projects (Exh. DPU-AG-2-1, Att.).

The Department has reviewed the project documentation for these 14 projects, including work orders, variance reports, capital authorizations, and closing reports[56] (Exh. DPU-AG-2-1; see, e.g., Exhs. NSTAR-LML-5, 2013, Non-Discretionary, 11451, at 5; NSTAR-LML-5, 2006, Non-Discretionary, 25072, at 8; NSTAR-LML-5, 2008, Non-Discretionary, 07463, at 4). Based on our review of the documentation, the Department finds that the costs of the projects, including variances, were prudently incurred. Further, we find that the Company has demonstrated that these projects are used and useful in service to customers. Accordingly, the Department will include the costs of these 14 projects in rate base.

There are eight remaining projects that have positive cost variances and, according to the Attorney General, lack any explanation for cost variances (Exh. DPU-AG-2-1, Att.). The Company allocated additional funds to project 11541 to install security cameras to prevent theft and address other security issues (Exh. NSTAR-LML-5, 2012, Non-Discretionary, 11541).

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ten projects and finds that the project costs were prudently incurred and the projects are used and useful in service to customers (see Exhs. NSTAR-LML-4-C; NSTAR-LML-5; DPU-AG-2-1, Att.). Accordingly, the Department will include the cost of these projects in rate base.

56 For example, the causes of these variances included: (1) changes in the Company's information technology capitalization policy; (2) use of newer vendors; (3) higher bids than expected; and (4) additional equipment or labor (Exh. DPU-AG-2-1, Att.; see, e.g., Exhs. NSTAR-LML-5, 2013, Non-Discretionary, 11451, at 5; NSTAR-LML-5, 2006, Non-Discretionary, 25072, at 8; NSTAR-LML-5, 2008, Non-Discretionary, 07463, at 4).

Based on our review of the documentation for project 11541 (i.e., capital authorization, variance report, and closing report), the Department finds that NSTAR Gas has adequately explained and justified the cost variance for this project (Exh. NSTAR-LML-5, 2012, Non-Discretionary, 11541).

Project 12704 is a blanket authorization for the removal and replacement of obsolete furniture (Exh. NSTAR-LML-5, 2012, Non-Discretionary, 12704). NSTAR Gas closed to plant total direct costs of $51,401, resulting in a $14,151 cost variance (Exhs. NSTAR-LML-5, 2012, Non-Discretionary, 12704; NSTAR-LML-3, Schs. 2012-A-3, 2013-A-3). Pursuant to the Company's current project authorization policy, NSTAR Gas did not prepare a supplemental authorization to explain the costs over budget because the total direct costs of the project are less than $100,000 (Exhs. NSTAR-LML-1, at 17-18; DPU-13-13; DPU-13-14; DPU-13-15). Based on our review of the documentation for project 12704 (i.e., capital authorization and closing report), the Department finds that NSTAR Gas has adequately explained and justified the cost variance for this project (Exh. NSTAR-LML-5, 2012, Non-Discretionary, 12704).

Projects 08702 and 09702 are annual line-of-business authorizations to upgrade facilities, buildings, and equipment (Exhs. NSTAR-LML-5, 2008, Non-Discretionary, 08702, at 10; NSTAR-LML-5, 2009, Non-Discretionary, 09702, at 6). The upgrades are generally related to safety issues, building code requirements, and security (Exhs. NSTAR-LML-5, 2008, Non-Discretionary, 08702, at 10; NSTAR-LML-5, 2009, Non-Discretionary, 09702, at 6). The total amounts closed to plant for these projects were $354,595 and $133,701, respectively, exceeding the authorized amounts by $172,445 and $41,701, respectively

(Exhs. NSTAR-LML-5, 2008, Non-Discretionary, 08702, at 1; NSTAR-LML-5, 2009, Non-Discretionary, 09702, at 1).

Each year, the Company develops a list of building, facility, and equipment upgrade projects for a specific budgeted funding level (Exhs. NSTAR-LML-5, 2008, Non-Discretionary, 08702, at 12; NSTAR-LML-5, 2009, Non-Discretionary, 09702, at 7). The Company states that it may substitute other projects for those on the approved list as priorities change throughout the year (Exhs. NSTAR-LML-5, 2008, Non-Discretionary, 08702, at 12; NSTAR-LML-5, 2009, Non-Discretionary, 09702, at 7). The Company provided both the budgeted list and the actual list of projects (Exhs. NSTAR-LML-5, 2008, Non-Discretionary, 08702; NSTAR-LML-5, 2009, Non-Discretionary, 09702).

Consistent with the Company's current project authorization policy, these infrastructure upgrade projects exceeded $100,000 and had a specific project authorization or a P&N (Exhs. NSTAR-LML-5, 2008, Non-Discretionary, 08702, at 10-16; NSTAR-LML-5, 2008, Non-Discretionary, 09702, at 6-21). The Attorney General contests these projects on the basis that, while the Company provided the total dollar value of the variance, it did not itemize the dollar value attributable to each explanation for the variance (Attorney General Brief at 11, citing Exh. DPU-AG-2-1, Att.).

The Department finds that the Company has provided sufficient explanation for cost variances and, in these instances, a further breakdown of the costs is not required in order for the Department to assess prudence. Based on our review of the documentation for projects 09702 and 08702 (i.e., capital authorizations, variance reports, and closing reports), the Department finds that NSTAR Gas has adequately explained and justified the cost variance for these projects

(Exhs. NSTAR-LML-5, 2008, Non-Discretionary, 08702, at 15-16, 21; NSTAR-LML-5, 2008, Non-Discretionary, 09702, at 8, 14).

Project 04442 is a child project authorization of parent project 25076 (Exh. NSTAR-LML-4-C, at 16). Pursuant to the Company's current project authorization policy, supplemental authorizations are provided at the parent project level but not the child project level (Exhs. DPU-13-13, Att. (g) at 3; AG-16-22). For this project, however, the Company provided project documentation at the parent project level as well as the child project level (see Exh. NSTAR-LML-5, 2005, Non-Discretionary, 04442).

Contrary to the Attorney General's assertions, the Department finds that the Company provided an initial P&N authorization and supplemental authorization documentation for this project (Exh. NSTAR-LML-5, 2005, Non-Discretionary, 04442, at 4, 38). Based on the Department's review of the project documentation, we find that NSTAR Gas appropriately explained and justified the cost variance for project 04442.

Based on the above, Department finds that the costs of projects 11541, 12704, 09702, 08702, and 04442, including variances, were prudently incurred. Further, we find that the Company has demonstrated that these projects are used and useful in service to customers. Accordingly, the Department will include the costs of these five projects in rate base.

Project 35078 is a parent project of two child projects, 10465 and 10466. At the parent level, the Company closed to plant total direct costs of $468,795, resulting in a direct cost variance of $125,828[57] (Exhs. NSTAR-LML-5, 2011, Non-Discretionary, 35078;

57 The direct and indirect cost variance for this project is $131,812 (Exhs. NSTAR-LML-5, 2011, Non-Discretionary, 35078; NSTAR-LML-3, Sch. 2012-A-3, at 1).

NSTAR-LML-3, Sch. 2012-A-3). Pursuant to its current project authorization policy, NSTAR Gas verifies that the estimates of child projects match parent projects, however, the parent project authorization is the final approval of the entire project (Exhs. DPU-13-13, Att. (g) at 3; AG-16-22). Further, a supplemental authorization must be prepared if direct spending exceeds the authorized level by $50,000 for projects more than $250,000, but less than or equal to $500,000 (Exh. NSTAR-LML-1, at 17-18).

The Company did not provide a supplemental explanation describing the reasons for the $125,828 cost variance for project 35078. Based on our review, the Department finds that the Company failed to document sufficiently the reasons for the cost variances for project 35078. Accordingly, the Department reduces the Company's plant in service by $129,975.[58] The Company booked 67 percent of total costs for this project to Account 391-Office Furniture and Equipment and 33 percent of total costs for this project to Account 303-Miscellaneous Intangible Plant (Exh. NSTAR-LML-3, Schs. 2011-A-3, at 1; 2012-A-3, at 1; 2013-A-3, at 1). Accordingly, the Department allocates $87,002 of the disallowance to Account 391 and $42,972 of the disallowance to Account 303.

The Company completed an IT project through child project 09421, under parent project 35054 (Exh. NSTAR-LML-5, 2010, Non-Discretionary, 09421, at 1). NSTAR Gas closed to plant total direct costs of $147,123, resulting in a cost variance of $144,197 (Exhs. NSTAR-LML-5, 2010, Non-Discretionary, 09421, at 1; DPU-8-13, Att. F). During

[58] The proportion of the direct cost variance to total direct costs is 27 percent. The project incurred total indirect costs of $15,450 (Exh. NSTAR-LML-5, 2011, Non-Discretionary, 35078). Thus, 47 percent of indirect costs are $4,147. Therefore, the Department reduces the Company's plant in service by $125,828 plus $4,147 for a total of $129,975.

discovery, the Company identified a $132,771 invoice inappropriately charged to NSTAR Gas instead of NSTAR Electric (Exh. AG-16-45). Accordingly, the Company reduced its rate base by the plant investment, associated depreciation, and accumulated deferred income taxes (Exh. DPU-19-2). Thus, actual direct costs for this project are less than $50,000, resulting in a cost variance of $23,372. Pursuant to the Company's capital authorization policy, project 09421 does not require supplemental cost variance analysis documentation (see Exh. DPU-13-13. Atts.).

When the Company reduced its rate base, NSTAR Gas failed to make an appropriate corresponding adjustment to the indirect costs for project 09421. NSTAR Gas allocates indirect costs[59] based on a project's direct costs (Exh. DPU-3-8). According to the closing report, the Company closed to plant $11,658 of indirect costs during the month that the $132,770 invoice was booked to the project (Exh. NSTAR-LML-5, 2010, Non-Discretionary, 09421, at 33, 35). Accordingly, the Department reduces the Company's plant in service by an additional $11,658. Because the Company booked this project to Account 303-Miscellaneous Intangible Plant, the Department allocates this disallowance to Account 303 (Exh. DPU-8-13, Att. (f)).

Finally, project 12417 is a child project, with $1,856,520 direct costs estimated at the parent level, of which $6,986 were allocated to NSTAR Gas (Exh. NSTAR-LML-5, 2012, Non-Discretionary, 12417). The purpose of this project was to replace information technology systems at the end of their useful lives (Exh. NSTAR-LML-5, 2012, Non-Discretionary, 12417, at 5). Ultimately, the Company closed to plant $66,983 in direct costs and $2,452 of indirect

[59] The Company charges indirect costs to capital projects each year (Exh. DPU-3-8). NSTAR Gas determines the allocation rates based on historical data for the budget year (Exh. DPU-3-8). The indirect costs are allocated to capital projects based on direct charges (Exh. DPU-3-8).

costs, resulting in a direct cost variance of $60,017 (Exhs. NSTAR-LML-5, 2012, Non-Discretionary, 12417; NSTAR-LML-3, Sch. 2013-A-3, at 1).

As discussed above, pursuant to the Company's project authorization policy, NSTAR Gas treats the parent project authorization as final approval of the entire project (Exhs. DPU-13-13, Att. (g) at 3; AG-16-22). The Company maintains, however, that it verifies that estimates of child projects match parent projects (Exhs. DPU-13-13, Att. (g) at 3; AG-16-22).

Given that the Company inappropriately allocated costs to child project 09421, as discussed above, and the significant cost variance for the instant project, the Department is concerned that the Company's policy to review cost variances at the parent level may mask issues at the child level that require further review. For example, the potential exists for inappropriate allocations between gas and electric operations, if NSTAR Gas only reviews cost variances at parent level.

A company must demonstrate that it maintained adequate cost control. Boston Gas Company, D.P.U. 93-60, at 35-36, 36 n.13 (1993). While a project may not be over budget in the aggregate at the parent project level, the Department finds that reviewing cost variances at the child level would maintain better cost controls, especially in instances where the overrun exceeds 100 percent (see Exh. NSTAR-LML-5, 2012, Non-Discretionary, 12417). Moreover, the Company did not provide any documentation for the parent project, 35098. At a minimum, such documentation would have allowed the Department to review and evaluate actual spending at the parent project level of all child projects. Going forward, as discussed further in Section IV.B.6.d above, the Company will be required to provide documentation for parent projects for the associated child projects it is proposing to include in rate base with all of its capital project documentation. Further, the Company shall review cost variances at the child project level.

For the reasons discussed above, the Department finds that the Company failed to document sufficiently the reasons for the cost variances for project 12417. Accordingly, the Department reduces the Company's plant in service by $62,213[60] in cost variance for project 12417, booked to Account 303 (Exh. NSTAR-LML-3, Sch. 2013-A-3, at 1).

iv. Conclusion

Based on our review of the Company's individually authorized projects, the Department has excluded $576,975 in pre-2014 plant additions from rate base. The disallowance includes $238,450 for three Type A projects, $134,679 for one Type B project, and $203,846 for three Type C projects. This disallowance was not based on our determination that the projects in question were imprudent or that the projects are not providing benefits to customers. Rather, the Department determined that the Company has not provided clear and cohesive reviewable evidence on certain rate base additions and did not bear its burden of demonstrating the propriety of additions to rate base. D.P.U. 95-40, at 7; D.P.U. 93-60, at 26; D.P.U. 92-210, at 24; see also 376 Mass. 294, 304; 352 Mass. 18, 24-25.

In recognition of the Department's decision to exclude these plant additions from rate base, a corresponding adjustment to the Company's depreciation reserve is required. D.P.U. 10-55, at 193-194; Aquarion Water Company of Massachusetts, D.P.U. 08-27,

60 Project 12417 had a direct cost variance of $60,017. The project incurred total direct costs of $67,003. The proportion of the direct cost variance to total direct costs is 90 percent. The project incurred total indirect costs of $2,452. Thus, 90 percent of indirect costs is $2,196. Therefore, the Department reduces the Company's plant in service by $60,017 plus $2,196, for a total of $62,213.

at 16-17 (2009); D.T.E. 03-40, at 71. The Company applies account-specific depreciation accrual rates to determine the account's depreciation reserve (Exh. NSTAR-JJS-3, at 2). Of the seven projects with disallowances, two projects represented by work orders 1270184 and 1227865, with a total disallowance of $186,126, pertain to gas mains booked to Account 367 in 2005. A third project represented by authorization 1261447, with a total disallowance of $52,324, pertains to mains booked to Account 367 in 2006. A fourth project represented by authorization 13843, with a total disallowance of $134,679, pertains to mains booked to Account 367 in 2013. The current depreciation accrual rate for Account 367 is 1.87 percent (Exh. NSTAR-JJS-3, at 2).

To calculate the accumulated depreciation associated with work orders 1270184 and 1227865, the Department multiplied the total disallowance of $186,126 by the current 1.87 percent depreciation accrual rate for Account 367, and multiplied the result by the nine years between 2005 and 2013 (i.e., the end of the test year in this proceeding). This calculation produces an accumulated depreciation balance of $31,325. Accordingly, the Department reduces the Company's proposed depreciation reserve by $31,325.

To calculate the accumulated depreciation associated with work order 1261447, the Department multiplied the total disallowance of $52,324 by the current 1.87 percent depreciation accrual rate for Account 367, and multiplied the result by then eight years between 2006 and 2013 (i.e., the end of the test year in this proceeding). This calculation produces an accumulated depreciation balance of $7,828. Accordingly, the Department reduces the Company's proposed depreciation reserve by $7,828.

To calculate the accumulated depreciation associated with project 13843, the Department multiplied the total disallowance of $134,679 by the current 1.87 percent depreciation accrual rate for Account 367. This calculation produces an accumulated depreciation balance of $2,519. Accordingly, the Department reduces the Company's proposed depreciation reserve by $2,519.

The fifth disallowance is project 35078, with a total disallowance of $129,975, of which $87,002 pertains to office furniture and equipment booked to Account 391 in 2011, and $42,972 pertains to miscellaneous intangible plant booked to Account 303 in 2011. The current amortization accrual rate for Account 391 is 6.87 percent (Exh. NSTAR-JJS-3, at 2). To calculate the accumulated amortization associated with Account 391 for project 35078, the Department multiplied the disallowance of $87,002 by the 6.87 percent amortization accrual rate for Account 391, and multiplied the result by three years. This calculation produces an accumulated amortization balance of $17,931. Accordingly, the Department reduces the Company's proposed amortization reserve by $17,931.

To calculate the accumulated amortization associated with project 35078, the Department multiplied the total disallowance of $42,972 by the current 20 percent amortization rate used for Account 303, and multiplied the result by the three years between 2011 and 2013. This calculation produces an accumulated amortization balance of $25,783. Accordingly, the Department reduces the Company's proposed amortization reserve by $25,783.

The sixth disallowance is project 09421, with a total disallowance of $11,658, pertains to miscellaneous intangible plant booked to Account 303 in 2010. To calculate the accumulated amortization associated with project 09421, the Department multiplied the total disallowance of $11,658 by the current 20 percent amortization rate used for Account 303, and multiplied the result by the four years between 2010 and 2013. This calculation produces an accumulated amortization balance of $9,326. Accordingly, the Department reduces the Company's proposed amortization reserve by $9,326.

Finally, project 12417, with a total disallowance of $62,213, pertains to miscellaneous intangible plant and booked to Account 303 in 2013. To calculate the accumulated amortization associated with project 12417, the Department multiplied the total disallowance of $62,213 by the current 20 percent amortization rate used for Account 303. This calculation produces an accumulated amortization balance of $12,443. Accordingly, the Department reduces the Company's proposed amortization reserve by $12,443.

Based on the foregoing analysis, the Department reduces the Company's depreciation and amortization expense associated with pre-2014 plant disallowances by $107,155. The above adjustments also make it necessary to eliminate the associated deferred income taxes from the Company's proposed rate base associated with the disallowed plant additions. These adjustments are described in Section IV.E.2 below.

f. <u>2014 Plant Additions</u>

i. <u>Capital Projects $50,000 and Below</u>

During 2014, the Company completed 3,913 projects with budgets of $50,000 or less (Exh. DPU-3-2, Att. (Supp. 1)). The Department has reviewed the information provided by the Company for these projects and finds that the project costs were prudently incurred and the projects are used and useful in service to customers (Exhs. NSTAR-LML-3 (Supp.); DPU-19-9, Atts.; DPU-3-2, Att. (Supp. 1)). Accordingly, the Department allows the cost of these projects to be included in rate base.

ii. Capital Projects over $50,000

(A) Overview

From January 1, 2014 to December 31, 2014, the Company completed 203 projects with total costs in excess of $50,000[61] (Exhs. NSTAR-LML-3 (Supp.) & Schs.; NSTAR-LML-5 (Supp.); DPU-3-2, Att. (Supp. 1)). Of the 203 projects, 70 were completed at or under budget and 133 were over budget[62] (see Exh. DPU-19-10, Atts.). As described in Section IB.B.2 above, the estimated project cost threshold requiring the use of a P&N is $100,000 (Exhs. NSTAR-LML-1, at 19; AG-16-12). The Company states, however, that due to a system conversion to consolidate its operating affiliates onto a common accounting platform, the threshold requiring the use of a P&N was increased to $200,000 in 2014 (Exh. DPU-20-6). Accordingly, in 2014, the Company provided variance analyses only for projects at or above $200,000 where the cost variances met the Company's predetermined thresholds for additional analysis[63] (Exhs. DPU-20-6; DPU-19-10, Atts.).

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61 Of these 203 projects, the Attorney General contests 137 Type B projects and one Type C project. These contested projects are discussed in Section IV.B.6.f.ii, below (see Exh. DPU-AG-2-1, Att.). Three of these Type B projects were duplicated in her analysis; therefore, in total, the Attorney General contests 135 of the 203 projects (Exh. DPU-AG-2-1, Att.). Additionally, the Attorney General contests two of the 42 projects that NSTAR Gas categorizes as "prior year specifics" (Exhs. DPU-AG-2-1, Att.; NSTAR-LML-3 (Supp.) Sch. 2014-E-1). Therefore, the Department will analyze 133 projects contested by the Attorney General in the following sections. The Department will address the projects classified as "prior year specifics" separately.

62 Of the 70 projects identified as being completed at or under budget, 15 lacked project costs estimates because they were emergent work projects. In addition, 23 projects for services relays lacked project cost estimates because the pre-construction estimates were developed only for the associated mains relay projects (Exh. DPU-19-10, Att. (b)).

63 These thresholds are described in Section IV.B.2 above.

Of the 70 projects that were completed at or under budget, 46 projects were challenged by the Attorney General and are discussed in Section IV.B.6.f.ii, below. Accordingly, 24 unchallenged projects were completed at or under budget. Of these unchallenged projects, the Department has examined the documentation provided by the Company for the projects that are at or under budget, including work orders, capital authorizations, and closing reports (Exh. NSTAR-LML-5 (Supp.)). The Department finds that level of documentation provided by the Company adequately supports our ability to review the prudence of the proposed projects. Based on our review of the documents, the Department finds that the costs for these 24 projects were prudently incurred and that the capital investments are used and useful in service for customers. Accordingly, the Department will include the cost of these 24 uncontested projects in plant in service.

Of the 133 projects that were completed over budget, 87 projects were challenged by the Attorney General and are discussed in Section IV.B.6.f.ii, below. Accordingly, 46 projects were completed over budget but unchallenged by the Attorney General. Of these unchallenged projects, the Department separately addresses six projects below.

For the remaining 40 projects, the Department has reviewed the documentation provided by the Company for the projects that were completed over budget, including work orders, capital authorization, variance reports, and closing reports (Exh. NSTAR-LML-5 (Supp.)). The Department finds that level of documentation provided by the Company adequately supports our ability to review the prudence of the proposed projects. Based on our review of the documents, the Department finds that the costs for these 40 projects were prudently incurred and that the capital investments are used and useful in service for customers. Accordingly, the Department will include the cost of these 40 uncontested projects in rate base.

The Department reviewed the documentation for project 99816, work order 1989745 (Exh. NSTAR-LML-5 (Supp.) Revenue, 99816 WO 1989745). The Department finds that the Company did not provide a cost estimate for this revenue-producing project (see Exh. NSTAR-LML-5 (Supp.) Revenue, 99816 WO 1989745). Consequently, NSTAR Gas did not perform a pre- and post-construction return or cost-benefit analysis (see Exh. NSTAR-LML-5 (Supp.) Revenue, 99816 WO 1989745). Therefore, the Department finds that the Company failed to demonstrate the prudence of project 99816, work order 1989745. Accordingly, the Department reduces the Company's plant in service by the total cost of this project, $66,713.

For project 99841, work order 1985820, the Company incurred a net cost for mains of $90,896 and total costs of $118,601 (Exh. NSTAR-LML-5 (Supp.) Revenue, 99841 WO 1985820, at 1). For project 99841, work order 1997732, NSTAR Gas incurred a net cost for mains of $90,350 and total costs of $124,055 (Exh. NSTAR-LML-5 (Supp.) Revenue, 99841 WO 1997732, at 1). For project 99843, work order 1955482, the Company incurred total costs of $74,183 (Exh. NSTAR-LML-5 (Supp.) Revenue, 99843 WO 1955482, at 1). The Company's project authorization analyses indicates that CIAC was required in the amounts of $29,973, $55,937, and $67,771 for these projects, respectively (Exhs. DPU-19-10, Att. (f) at 39, 51, and 60). The Company did not, however, provide evidence that the total costs of these projects were reduced by the requisite CIAC (see Exhs. DPU-5-3, at 26; NSTAR-LML-5 (Supp.) Revenue, 99841 WO 1985820, at 1; NSTAR-LML-5 (Supp.) Revenue, 99841 WO 1997732, at 1;

NSTAR-LML-5 (Supp.) Revenue, 99843 WO 1955482, at 1). Moreover, the Company received $1,203 in CIAC for project 99841 work order 1985820, yet it does not appear as a reduction to this project's total costs (Exh. DPU-5-3, at 26). Consequently, the Department is unable to determine whether these projects were cost-effective or prudently incurred. Accordingly, the Department reduces the Company's plant in service by the net cost of mains[64] for work orders 1985820 and 1997732, and the total cost for work order 1955482 as follows: (1) $90,896 for project 99841, work order 1985820; (2) $96,350 for project 99841, work order 1997732; and (3)$74,183 project 99843, work order 955482.

Finally, project 99965, work order 1807922 and project 99967, work order 2007444 both incurred total costs exceeding $100,000, with project cost variances exceeding $25,000. The Company's current capital authorization policy requires a supplemental authorization if direct spending on a project with direct costs in excess of $50,000, but less than $250,000, exceeds the authorized level by $25,000 (Exhs. NSTAR-LML-1, at 17-18). However, because of its systems conversion, NSTAR Gas was unable to quantify direct and indirect costs for projects completed during 2014 (Exhs. DPU-20-5; DPU-20-6).

Given our findings above on the Company's capital project policy changes during 2014, and that fact that NSTAR Gas was unable to differentiate between direct costs and indirect costs, the Department finds that NSTAR Gas failed to provide sufficient evidence to support the cost variance for these two projects. Accordingly, the Department reduces the Company's plant in

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64 The Company books the service and meter costs to a separate work order (see Exhs. NSTAR-LML-5 (Supp.) Revenue, 99841 WO 1985820, at 1; NSTAR-LML-3, Sch. 2014-B-2).

service by the cost variances for these two projects: (1) $28,919 for project 99965, work order 1807922; and (2) $37,475 for project 99967, work order 2007444.

In total, of the 70 uncontested projects, the Department: (1) allows 64 capital projects completed by the Company during 2014 (i.e., 24 at or under budget and 40 over budget); (2) disallows total project costs for four projects; and (3) disallows project cost variances for two projects. In the sections below, the Department addresses the 133 remaining projects completed by the Company during 2014 with total costs in excess of $50,000 and contested by the Attorney General. As discussed above, the Attorney General requests that the Department deny a portion of the costs of these projects because they lack sufficient support for variances (i.e., Type B and Type C projects) (Attorney General Brief at 11, citing D.P.U. 12-25, at 83; D.P.U. 09-30, at 114; see also Exh. DPU-AG-2-1, Att.).

(B) Type B/Non-Revenue Projects and Type C/Non-Discretionary Projects

The Attorney General asserts that 132 non-revenue projects and one non-discretionary project completed by the Company during 2014 lack supporting documentation for cost variances greater than 30 percent (i.e., 132 Type B projects and one Type C project) (Attorney General Brief at 10-11, citing Exh. DPU-AG-2-1, Att.). Of the 133 projects, 46 had negative cost variances (i.e., the projects were under budget) (see Exh. DPU-AG-2-1, Att.). Accordingly, the Department finds it unnecessary to conduct a full examination of the prudence of such variances. See D.P.U. 96-50 (Phase I) at 23. The Department has reviewed the information provided by the Company for these 46 projects and finds that the project costs for 39 of these projects were prudently incurred and the projects are used and useful in service to customers (see Exhs. NSTAR-LML-5 (Supp.); DPU-19-8, Att.; DPU-19-10, Atts.; DPU-AG-2-1, Att.). Accordingly, the Department allows the cost of these 39 projects to be included in rate base. The Department addresses the seven remaining projects below.

The Company did not provide a cost estimates for these seven projects (see, e.g., Exh. NSTAR-LML-5 (Supp.) Non-Revenue, 99838 WO 1932203, at 1). Each of these projects incurred total costs greater than $100,000 (Exh. DPU-19-10, Att. (b)). Pursuant to its current capital project authorization policy, the Company does not develop estimates for services relay projects associated with existing mains relay projects (see, e.g., Exh. NSTAR-LML-5 (Supp.) Non-Revenue, 99838 WO 1932203, at 1). A company's internal project cost estimation policies cannot, however, override the company's obligation to demonstrate to the Department the prudence of its capital project costs. A project incurring total costs in excess of $100,000 is neither small nor routine, and requires its own costs estimates in order to maintain proper cost control. Therefore, the Department finds the Company has failed to demonstrate the prudence of these projects. Accordingly, the Department reduces the Company's plant in service by $1,107,654.

The remaining 87 projects had cost overruns greater than 30 percent, with variances ranging from 37 percent to 1,078 percent (Exh. DPU-AG-2-1, Att.). Blanket authorizations were used for 52 of these projects (see Exh. DPU-AG-2-1, Att.).

The Department has reviewed the total project costs, including overruns, for the 52 over budget blanket projects contested by the Attorney General. Of these 52 blanket projects, 21 projects had estimated and total costs less than $100,000 (see Exhs. DPU-19-10, Atts.; DPU-AG-2-1, Att.). Under the Company's prior and current project authorization policy, these 21 projects did not require a supplemental explanation or authorization for the variances (see Exh. NSTAR-LML-1, at 17-19; AG-16-12). However, the Company provided estimated costs, actual costs, and closing reports for these 21 blanket projects (see Exhs. NSTAR-LML-5 (Supp.); DPU-19-10, Atts.).

For each project, the Company provided the level of data specified under its current capital authorization policy to support its initial cost estimates and variances[65] (see Exhs. NSTAR-LML-4-A; NSTAR-LML-5 (Supp.); DPU-AG-2-1, Att.). Together with the process the Company has in place to monitor and control costs, the Department finds that the costs of the 21 blanket projects, including the project variances, were prudently incurred. Further, we find that the Company has demonstrated that each project is used and useful in service to customers. Accordingly, the Department allows the cost of these 21 blanket projects to be included in rate base.

For each of the remaining 31 blanket projects, the Company incurred costs exceeding $100,000, but was unable to identify the total direct costs (Exhs. DPU-19-8; DPU-19-10, Atts.; DPU-20-5; DPU-20-6). Pursuant to NSTAR Gas' current capital authorization policy, a project with direct costs in excess of $50,000 but less than $250,000, requires a supplemental authorization if direct spending for projects exceeds the authorized level by $25,000 (Exhs. NSTAR-LML-1, at 17-18). The Company did not provide a supplemental authorization for these projects (see, e.g., Exh. NSTAR-LML-5 (Supp.) Non-Revenue, 99853 WO 1993050). Given that the Company was unable to provide evidence of the direct costs associated with these 31 blanket projects, the Department must examine the prudence of these blanket projects based on each project's total costs.

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65 As discussed in Section IV.B.6.e.1 above, the Company will be required to provide additional documentation to support project cost variances.

The Company provided work project estimates and closing reports for these 31 blanket projects (see, e.g., Exh. NSTAR-LML-5 (Supp.) Non-Revenue, 99853 WO 1993050). The Department finds that the Company failed to document the cost variances associated with these 31 blanket projects. Project managers were responsible for managing the process to control costs and periodically reported to supervisors on project costs and progress (Exh. DPU-20-6). In Section IV.B.6.e.i above, the Department determined that projects of this magnitude are not smaller, routine, or low-cost projects and require documentation on cost variances. Therefore, the Department finds that the Company has failed to demonstrate that the cost variances for these projects were prudently incurred (see Exhs. NSTAR-LML-5 (Supp.); DPU-19-10, Atts.; DPU-AG-2-1, Att.). Accordingly, the Department reduces the Company's plant is service by the cost variances of these 31 blanket projects, $2,271,794.

Regarding the 35 over budget non-blanket projects contested by the Attorney General, the Department has reviewed the information provided by the Company for these projects. Our findings are explained below.

The Company incurred $293,367 for project 12809 (Exh. DPU-19-10, Att. (b)). NSTAR Gas explains that 50 percent of the cost of this project is reimbursable by the Massachusetts Department of Transportation ("MA DOT") (Exh. NSTAR-LML-5 (Supp.) Non-Revenue, 12809). The Company has not yet received the reimbursement and, therefore, has not reduced the amount included in plant in service by 50 percent for this project (Exhs. DPU-19-10, Att. (b); DPU-20-7). The Department finds that the Company's proposed inclusion in cost of service of $146,684 in costs that will be reimbursed by MA DOT for project 12809 is inappropriate.

See Fitchburg Gas and Electric Light Company, D.P.U.13-90, at 140 (2014). Accordingly, the Department reduces the Company's plant in service by $146,684.

With respect to projects 13972, 13973, 13974, and 13978, the total cost for each project exceed $200,000 and each project had a cost variance greater than $25,000 (Exh. DPU-19-10, Att. (b)). As noted above, pursuant to NSTAR Gas' current capital authorization policy, a project with direct costs in excess of $50,000 but less than $250,000, requires a supplemental authorization if direct spending for projects exceeds the authorized level by $25,000 (Exhs. NSTAR-LML-1, at 17-18). The Company did not provide a supplemental authorization for these projects (see, e.g., Exh. NSTAR-LML-5 (Supp.) Non-Revenue, 13972). Given that the Company was unable to provide evidence of the direct costs associated with these four projects, the Department must rely on each project's total costs.

The Company provided initial project authorizations, work project estimates, and closing reports for these projects (see, e.g., Exh. NSTAR-LML-5 (Supp.) Non-Revenue, 13972). Despite its use of a $200,000 total cost threshold for cost variance analyses in 2014, the Department finds that the Company failed to document the cost variances associated with projects 13972, 13973, 13974, and 13978, (Exh. DPU-20-5; DPU-20-6). Therefore, the Department finds that the Company has failed to demonstrate that the costs variances for these projects were prudently incurred (see Exhs. NSTAR-LML-5 (Supp.) Non-Revenue, 13972; 13973; 13974; and 13978; DPU-19-10, Atts.; DPU-AG-2-1, Att.). Accordingly, the Department reduces the Company's plant in service by the cost variances of these projects of $641,710.

For the remaining 30 contested projects exceeding authorized budgeted amounts, the Attorney General contests these projects on the basis that, while the Company provided the total dollar value of the variance, it did not itemize the dollar value attributable to each explanation for the variance (Attorney General Brief at 11, citing Exh. DPU-AG-2-1, Att.).

The Company provided variance reports or explained cost variances for these projects (see, e.g., Exhs. NSTAR-LML-5 (Supp.) Non-Revenue, 14809; NSTAR-LML-5 (Supp.) Non-Revenue, 14839; NSTAR-LML-5 (Supp.) Non-Revenue, 13852). The variance reports include original and updated budgets, project descriptions, a breakdown of the change in cost elements, and short summaries of the reasons for budget variances (see, e.g., Exhs. NSTAR-LML-5 (Supp.) Non-Revenue, 14809; NSTAR-LML-5 (Supp.) Non-Revenue, 14839; NSTAR-LML-5 (Supp.) Non-Revenue, 13852). The variance detail provided by the Company indicates that the most common causes for a budget variance were: (1) ledge or other impediments that delayed digging; (2) delays due to conflicting schedules with other contractors; (3) extra loam and seeding needed for the project; and (4) project scoping changes caused by other non-utility work being done at the project site (see, e.g., Exhs. NSTAR-LML-5 (Supp.) Non-Revenue, 14809; NSTAR-LML-5 (Supp.) Non-Revenue, 14839; NSTAR-LML-5 (Supp.) Non-Revenue, 13852).

The Department finds that the Company has provided sufficient explanation for cost variances and, in these instances, a further breakdown of the costs is not required in order for the Department to assess prudence. Based on our review of the documentation for these 30 projects, the Department finds that NSTAR Gas has adequately explained and justified the cost variance for these projects. Further, the Department finds that the project costs were prudently incurred and the projects are used and useful in service to customers. Accordingly, the Department will include the cost of these 30 projects in plant in service.

(C) Prior Year Specific Projects

Costs relating to prior year specific projects refers to cost adjustments associated with projects that were placed into service in earlier years. The Company proposes to include costs associated with 42 prior year specific projects in its 2014 plant additions (Exh. DPU-19-9, Att.). The Attorney General contests two of these projects on the basis that, while the Company provided the dollar value of the total variance, it did not itemize the dollar value attributable to each explanation for the variance (Attorney General Brief at 11, citing Exh. DPU-AG-2-1, Att.).

The Department reviewed and approved the inclusion in rate base of the underlying projects in Section IV.B.6.e above. The Department has examined the additional documentation provided by the Company for these projects, including work orders, capital authorizations, and closing reports (Exh. NSTAR-LML-5 (Supp.)). For the two projects contested by the Attorney General, NSTAR Gas provided variance reports or explained cost variances for these projects (Exhs. NSTAR-LML-5 (Supp.) Non-Revenue, 12863, at 2; NSTAR-LML-5 (Supp.) Non-Revenue, 13838, at 2). The Department finds that the Company has provided sufficient explanation for the additional costs and, in these instances, a further breakdown of the costs is not required in order for the Department to assess the prudence of such costs (Exhs. NSTAR-LML-5 (Supp.) Non-Revenue, 12863; NSTAR-LML-5 (Supp.) Non-Revenue, 13838). Based on our review of the documents, the Department finds that the additional costs for these two projects were prudently incurred and that the capital investments are used and useful in service for customers. Accordingly, the Department allows the additional costs associated with these two projects to be included in rate base.

Regarding the remaining 40 projects, the Department is unable to determine the prudence of the additional costs associated with prior year specific projects because the record lacks supplemental project documentation to support these costs (see Exhs. NSTAR-LML-5 (Supp.); DPU-19-9, Att.). For example, the Company failed to provide documentation including closing reports, or other such evidence from its accounting systems, that it actually incurred these additional costs associated with prior year specific projects. Therefore, the Department finds that the Company has failed to demonstrate the prudence of the additional costs associated with 40 projects. Accordingly, the Department reduces the Company's plant in service by $1,546,022 (see Exh. DPU-19-9, Att.).

iii. Conclusion

Based on our review of the $69,038,516 in capital projects completed in 2014, the Department has excluded $6,108,401 in 2014 plant additions from rate base (Exh. NSTAR-LML-3 (Supp.)). The disallowance includes: (1) $328,143 associated with four revenue-producing projects; (2) $4,234,236 associated with 46 non-revenue producing projects; and (3) $1,546,022 in costs associated with prior year specific projects.[66] These disallowances were not based on our determination that the projects in question were imprudent or that the projects are not providing benefits to customers. Rather, the Department's disallowances here are based on our findings that the Company has not provided clear and cohesive reviewable evidence on certain rate base additions and did not bear its burden of demonstrating the propriety

66 Minor discrepancies in the amounts presented in this section appear to be due to rounding.

of additions to rate base. D.P.U. 95-40, at 7; D.P.U. 93-60, at 26; D.P.U. 92-210, at 24; see also 376 Mass. 294, 304; 352 Mass. 18, 24-25.

In recognition of the Department's decision to exclude these plant additions from rate base, a corresponding adjustment to the Company's depreciation reserve is required. D.P.U. 10-55, at 193-194; D.P.U. 08-27, at 16-17; D.T.E. 03-40, at 71. The Company applies account-specific depreciation accrual rates to determine the account's depreciation reserve (Exh. NSTAR-JJS-3, at 2). Of the 49 projects in 2014 with disallowances, 41 projects, with a total disallowance of $3,380,541, pertain to gas mains booked to Account 367 in 2014. Of the prior year specific project disallowance, $571,869 pertains to gas mains booked to Account 367 in 2014. The depreciation accrual rate in use during 2014 for Account 367 was 1.87 percent (Exh. NSTAR-JJS-3, at 2).

To calculate the accumulated depreciation associated with these projects, the Department multiplied the total disallowance of $3,952,409 by the 1.87 percent depreciation accrual rate for Account 367. This calculation produces an accumulated depreciation balance of $73,910. Accordingly, the Department reduces the Company's proposed depreciation reserve by $73,910.

Of the 50 projects with disallowances, eight projects, with a total disallowance of $1,181,838, pertains to gas services booked to Account 380 during 2014. Of the prior year specific project disallowance, $149,901 pertains to gas services booked to Account 380 during 2014. The depreciation accrual rate in use during 2014 for Account 380 was 4.13 percent (Exh. NSTAR-JJS-3, at 2). To calculate the accumulated depreciation associated with Account 380 for these projects, the Department multiplied the disallowance of $1,331,738 by the 4.13 percent depreciation accrual rate for Account 380. This calculation produces an accumulated depreciation balance of $55,001. Accordingly, the Department reduces the Company's proposed depreciation reserve by $55,001.

To calculate the accumulated depreciation associated with Account 369, the Department multiplied the $4,762 disallowance for costs associated with prior year specific projects in 2014, by the 4.75 percent depreciation rate used during 2014 for Account 369. This calculation produces an accumulated depreciation balance of $226. Accordingly, the Department reduces the Company's proposed depreciation reserve by $226.

To calculate the accumulated amortization associated with disallowance of costs for the prior year specific projects booked to Account 303 in 2014, the Department multiplied the total disallowance of $3,085 by the 20 percent amortization rate used during 2014 for Account 303. This calculation produces an accumulated amortization balance of $617. Accordingly, the Department reduces the Company's proposed amortization reserve by $617.

Of the 2014 prior year specific project disallowance, NSTAR Gas booked $784,048 to Account 390. The depreciation accrual rate used during 2014 for Account 390 is 2.22 percent (Exh. NSTAR-JJS-3, at 2). To calculate the accumulated depreciation associated with Account 390, the Department multiplied the disallowance of $784,048 by the 2.22 percent depreciation accrual rate for Account 390. This calculation produces an accumulated depreciation balance of $17,406. Accordingly, the Department reduces the Company's proposed depreciation reserve by $17,406.

Of the 2014 prior year specific project disallowance, the Company booked $32,357 to Account 391. The amortization accrual rate used during 2014 for Account 391 is 6.87 percent (Exh. NSTAR-JJS-3, at 2). To calculate the accumulated amortization associated with

Account 391, the Department multiplied the disallowance of $32,357 by the 6.87 percent amortization accrual rate for Account 391. This calculation produces an accumulated amortization balance of $2,158. Accordingly, the Department reduces the Company's proposed amortization reserve by $2,158.

Based on the above analysis, the total accumulated depreciation and amortization associated with the disallowed 2014 plant additions is $149,318. Therefore, the Department reduces the Company's proposed depreciation reserve by $149,318.

C. Non-Plant 2014 Adjustments

1. Introduction

The Company's initial filing reflected proposed plant in service at year-end 2013 plus projected plant additions, retirements, and depreciation activity through year-end 2014[67] (Exh. NSTAR-MFF-1, at 11). NSTAR Gas updated its filing on April 15, 2015 to reflect actual rate base activity through December 31, 2014 (Exhs. NSTAR-MFF-1, at 11; NSTAR-MFF-2 (April 15, 2015)). This activity results in a proposed net increase in rate base of $3,414,137[68] (Exh. NSTAR-MFF-2, Sch. MFF-27 (August 21, 2015)). Additionally, the Company revised its

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67 In its initial filing, the Company calculated its projected post-test year rate base balances at December 31, 2014 using actual plant and accumulated depreciation balances at October 31, 2104; projected capital additions, retirements, depreciation expense and cost of removal for November and December 2014; and projected accumulated deferred income tax balances at December 31, 2014 based on expected book and tax amounts (Exh. NSTAR-MFF-1, at 11-12). Additionally, NSTAR Gas included estimated December 31, 2014 balances for property tax, depreciation, and amortization expense (Exh. NSTAR-MFF-1, at 12).

68 As noted above, the Company's actual proposed 2014 rate base activity includes $39,409,687 in net utility plant, less $36,993,258 in deferred income taxes, $70,891 in customer deposits, $2,523 in materials and supplies, and $162,326 in cash working capital, plus $67,024 in customer advances and $1,166,424 in regulatory assets for 2014 activity (Exh. NSTAR-MFF-2, Sch. MFF-27 (August 21, 2015)).

revenue requirement to include updated, weather-normalized revenues in 2014 of $152,925,409, which represents a $3,979,382 increase from the Company's initial filing. (Exhs. NSTAR-MFF-2, Schs. MFF-5, MFF-33, at 9 (August 21, 2015); AG-4-8 Supp. 01; Tr. 9, at 825-827).

In Section IV.B.6.c, f above, we addressed the Company's proposal to include 2014 capital additions in rate base. In this section, the Department addresses the Company's related proposal to include in rate base post-test year non-plant related items through 2014.

2. Analysis and Findings

Consistent with our findings in Section IV.B.6.c above, the Department allows the post-test year rate base and revenue adjustments associated with the 2014 plant additions. Therefore, the Department allows the following 2014 balances in the Company's rate base: (1) $1,134,345 in customer deposits; (2) $5,867,383 in customer advances; and (3) $2,336,531 in materials and supplies (Exh. NSTAR-MFF-2, Sch. MFF-27 (August 21, 2015)). In addition, the Department allows the Company's proposed $3,979,382 adjustment to revenues related to updated 2014 billing determinants, for total firm distribution revenues of $152,925,409 (Exhs. NSTAR-MFF-2, Schs. MFF-5, MFF-33, at 9 (August 21, 2015)). The Department discusses the 2014 balances of accumulated deferred income taxes in Section IV.E, cash working capital in Section IV.D, and regulatory assets in Section VI.N.

D. 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 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 and 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 calculation.

Cash working capital needs have been determined through the use of either a lead-lag study or a 45-day O&M expense allowance. D.T.E. 03-40, at 92. In the absence of a lead-lag study, the Department has traditionally relied on the 45-day convention as reasonably representative of O&M working capital requirements. D.T.E. 05-27, at 98; D.P.U. 88-67 (Phase I) at 35. The Department, however, has expressed concern that the 45-day convention, first developed in the early part of the 20th century, may no longer provide a reliable measure of a utility's working capital requirements. D.T.E. 03-40, at 92; Fitchburg Gas and Electric Light Company, D.T.E. 98-51, at 15 (1998). In recent years, lead-lag studies have resulted in savings for ratepayers by reducing the cash working capital requirement below the 45-day convention. D.P.U. 11-01/D.P.U. 11-02, at 163, citing D.P.U. 10-114, at 108; D.P.U. 10-70, at 78; D.P.U. 10-55, at 204-205; D.P.U. 09-39, at 114; D.P.U. 09-30, at 151-152; D.P.U. 08-35, at 38; D.T.E. 05-27, at 99-100. For these reasons, the Department requires all electric and gas companies serving more than 10,000 customers to conduct a fully developed and reliable O&M lead-lag study. D.P.U. 11-01/D.P.U. 11-02, at 164.

2. Company's Lead-Lag Study

The Company's cash working capital allowance is divided into the following two components: (1) gas purchased working capital collected through the cost of gas adjustment clause ("CGAC"), and (2) O&M expense working capital that is included in base rates (Exh. NSTAR-MFF-1, at 82-83). For each component, the Department uses revenue lag days and expense lead days to determine the cash working capital requirement (Exh. NSTAR-MFF-1, at 83).[69] The Company conducted a lead-lag study using in-house personnel to update the net lag days associated with each component of its proposed cash working capital allowance (see Exhs. NSTAR-MFF-1, at 82; NSTAR-MFF-3).

a. Revenue Lag Days

The revenue lag consists of a "meter reading or service lag," "collection lag," and a "billing lag", the sum of which is the total revenue lag experienced by the Company (Exh. NSTAR-MFF-1, at 84). The Company calculated a meter reading or service lag of 15.21 days by dividing the number of billing days in the test year by twelve months, and then dividing the result in half to arrive at the midpoint of the monthly service periods (Exh. NSTAR-MFF-1, at 84). The collection lag, which reflects the time delay between the mailing of customer bills and the receipt of the billed revenues from customers, totaled 26.75 days and was obtained by the Company by dividing the average daily accounts receivable balance of certain sales and transportation accounts by the average daily gas revenues

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69 Revenue lag is the time, measured in days, between delivery of a service to NSTAR Gas customers and the receipt by NSTAR Gas of the payment for such service, while expense lead is the time, again measured in days, between the performance of a service on behalf of NSTAR Gas by a vendor and payment of such service by NSTAR Gas (Exh. NSTAR-MFF-1, at 83). Because distribution rates are based on revenues and expenses booked on an accrual basis, the revenue lag results in a need for capital while the expense lead offsets this need to the extent that the Company is typically not required to reimburse its vendors until after a service is provided (Exh. NSTAR-MFF-1, at 83).

(Exhs. NSTAR-MFF-1, at 84-85; NSTAR-MFF-3, Sch. WC-2, at 1, 8-10).[70] Finally, NSTAR Gas proposed to apply a billing lag of one day, based on the fact that most of the Company's customers are billed the day after meters are read[71] (Exh. NSTAR-MFF-1, at 85). The Company calculated a total revenue lag of 42.96 days by adding the number of days associated with each of the three revenue lag components (Exhs. NSTAR-MFF-1, at 86; NSTAR-MFF-3, Sch. WC-2, at 1).

b. Expense Lead – Purchased Gas

Purchased gas cash working capital provides cash working capital for expenses paid by NSTAR Gas on behalf of customers to gas suppliers, pipeline transportation providers and supplemental gas suppliers (Exh. NSTAR-MFF-1, at 86). NSTAR Gas recovers purchased gas cash working capital as a separate cost component of the Company's CGAC tariff (Exh. NSTAR-MFF-1, at 86). According to the Company, the purchased gas cash working capital allowance has been removed from the total cash working capital included in rate base; however, the Company notes that at the time of its next cost of gas adjustment ("CGA") filing, the cash working capital component of the CGA will be updated to account for the lead-lag factors approved in this proceeding (Exh. NSTAR-MFF-1, at 86).

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70 The Company calculated the collection lag by using a combination of daily balances and end of month balances generated from (1) the customer billing system for the majority of the accounts receivable accounts ("CIS balances"); (2) special ledger accounts; and (3) the reserve for uncollectible accounts (Exhs. NSTAR-MFF-1, at 84-85; NSTAR-MFF-3, Sch. WC-2, at 2-8, 10). The average daily gas revenues were calculated by dividing total gas revenues by 365 days (Exhs. NSTAR-MFF-1, at 85; NSTAR-MFF-3, Sch. WC-2, at 9).

71 The Company made no adjustment in the lead-lag study to account for customers for which additional time is required to process bills (Exh. NSTAR-MFF-1, at 85).

The Company determined the updated purchased gas net lag by comparing the revenue lag of 42.96 days to the expense lead associated with purchased gas (Exh. NSTAR-MFF-1, at 87). To determine the expense lead associated with purchased gas, the Company identified all relevant supplier invoices that were paid during the test year and calculated for each invoice the number of days from the midpoint of the related service period to the date the invoice was paid (Exhs. NSTAR-MFF-1, at 87; NSTAR-MFF-3, Sch. WC-3). The Company then dollar weighted, totaled, and averaged the days to arrive at an overall weighted average purchase gas expense lead (Exhs. NSTAR-MFF-1, at 87-88; NSTAR-MFF-3, Sch. WC-3). The Company's study produced an expense lead associated with purchased gas of 42.21 days (Exhs. NSTAR-MFF-1, at 87; NSTAR-MFF-3, Schs. WC-1, WC-3, at 3). When compared to the revenue lag of 42.96 days, the net lag for purchased gas is 0.75 days (42.96 – 42.21) (Exh. NSTAR-MFF-1, at 86). The purchased gas net lag, as reflected in the Company's November 2014 CGAC filing, was 16 days (Exh. NSTAR-MFF-1, at 86). Thus, as a result of its lead-lag study, the Company proposes to reduce the net lag for purchased gas by 15.25 days (Exh. NSTAR-MFF-1, at 87).

c. Expense Lead – O&M Cash Working Capital

The Company's O&M cash working capital is comprised of O&M expense and taxes other than income taxes (Exhs. NSTAR-MFF-1, at 88; see also NSTAR-MFF-2, Schs. MFF-32, MFF-33, at 6 (August 21, 2015)). NSTAR Gas pays these expenses to finance the activities conducted in service to customers before the Company receives payment from customers for those services (Exh. NSTAR-MFF-1, at 88). To calculate the O&M expense lead period, the Company disaggregated its non-gas O&M expense into several major cost categories (see Exhs. NSTAR-MFF-1, at 89; NSTAR-MFF-3, Sch. WC-4).[72] The Company reviewed test year payments and calculated the lead days for each category based on either all payments or a sampling of payments (Exhs. NSTAR-MFF-1, at 89; NSTAR-MFF-3, Schs. WC-5 through WC-10). Once the Company determined lead days for each category, it used the sum of the lead days weighted by dollars to arrive at an O&M expense lead days of 11.19 days (Exhs. NSTAR-MFF-1, at 89, 91; NSTAR-MFF-3, Sch. WC-4). The Company then subtracted the expense lead of 11.19 days from the revenue lag of 42.96 days to produce a net O&M expense lag of 31.77 days (Exh. NSTAR-MFF-1, at 91-92; NSTAR-MFF-3, Sch. WC-1). The Company derived an O&M expense cash working capital factor of 8.70 percent by dividing the net lag days of 31.77 by 365 days (Exhs. NSTAR-MFF-1, at 92; NSTAR-MFF-3, Sch. WC-1). This factor, multiplied by the total costs applicable to cash working capital of $86,590,952,[73] produces a proposed cash working capital allowance of $7,536,971 (Exh. NSTAR-MFF-2, Schs. MFF-32, MFF-33, at 6 (August 21, 2015)).

3. Positions of the Parties

NSTAR Gas summarized its proposal on brief (Company Brief at 46-47). The Company asserts that its lead-lag study is appropriate and, therefore, that its proposed cash working capital allowance should be adopted by the Department (Company Brief at 46-47). No other party commented on the Company's proposed cash working capital allowance.

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72 The categories are net payroll, regulatory expense, corporate insurance, service company billings, other O&M expense, property taxes, Social Security and Medicare expense, federal unemployment tax, and state tax (Exh. NSTAR-MFF-3, Sch. WC-4).

73 These costs are comprised of total O&M expense, less uncollectible accounts, plus taxes other than income taxes (Exh. NSTAR-MFF-2, Sch. MFF-32 (August 21, 2015)).

4. Analysis and Findings

The purpose of conducting a cash working capital lead-lag study is to determine a company's "cash in-cash out" level of liquidity in order to provide the company an appropriate allowance for the use of its funds. D.P.U. 87-260, at 22-23. Such funds are either generated internally or through short-term borrowing. See D.P.U. 96-50 (Phase I) at 26. Department policy permits a company to be reimbursed for costs associated with the use of its funds and for the interest expense incurred on borrowing. D.P.U. 96-50 (Phase I) at 26; D.P.U. 87-260, at 22. The Department requires all electric and gas companies serving more than 10,000 customers to conduct a fully developed and reliable O&M lead-lag study. D.P.U. 11-01/D.P.U. 11-02, at 164. In the event that the lead-lag factor is not below 45 days, a company will bear a heavy burden to justify the reliability of such a study and the reasonableness of the steps the company has taken to minimize all factors affecting cash working capital requirements within its control, such as the collections lag. D.P.U. 11-01/D.P.U. 11-02, at 164.

The Department has reviewed the evidence in support of the Company's lead-lag study and we conclude that the Company properly calculated the expense lead for purchased gas of 42.21 days and the net lag for purchased gas of 0.75 days (Exhs. NSTAR-MFF-1, at 86-87; NSTAR-MFF-3, Schs. WC-1, WC-3, at 3). Further, we find that the Company properly calculated (1) a total revenue lag of 42.96 days; (2) an O&M expense lead of 11.19 days; and (3) a resulting net O&M expense lag of 31.77 days (Exhs. NSTAR-MFF-1, at 82-92; NSTAR-MFF-2, Sch. MFF-32 (August 21, 2015); NSTAR-MFF-3, Schs. WC-1 through WC-10). The Company's proposed lead-lag factor of 31.77 days is lower than Department's 45-day convention (Exh. NSTAR-MFF-1, at 91-92; NSTAR-MFF-3, Sch. WC-1). For these reasons, the Department accepts the Company's lead-lag study. Further, we conclude that the Company's decision to perform a lead-lag study with in-house personnel was a cost-effective means to determine its working capital requirement. See D.P.U. 12-25, at 97.

Application of the cash working capital factor of 8.70 percent to the level of O&M and taxes other than income tax expense authorized by this Order produces a cash working capital allowance of $7,357,528 for the Company. The derivation of this cash working capital allowance is provided in Schedule 6 of this Order.

E. Accumulated Deferred Income Taxes

1. Introduction

At the end of the test year, NSTAR Gas recorded $140,264,553 in accumulated deferred income taxes (Exh. NSTAR-MFF-2, Schs. MFF-27, MFF-30 (August 21, 2015)). NSTAR Gas proposes to increase its deferred income tax reserve to $177,257,811, which includes a $36,993,258 adjustment for 2014 activity (Exh. NSTAR-MFF-2, Schs. MFF-27, MFF-30 (August 21, 2015)). No party specifically commented on the Company's proposal.

2. Analysis and Findings

Accumulated deferred income taxes represent a cost-free source of funds to utilities and, accordingly, are treated as an offset to rate base. Essex County Gas Company, D.P.U. 87-59, at 27 (1987); AT&T Communications of New England, D.P.U. 85-137, at 31 (1985); Boston Edison Company, D.P.U. 1350, at 42-43 (1983). Nonetheless, the Department has a general policy of matching recovery of tax benefits and losses to the recovery of the underlying expense with which the tax effects are associated. Commonwealth Electric Company, D.P.U. 89-114/90-331/91-80 (Phase One), at 29 (1991); Massachusetts Electric Company, D.P.U. 89-194/195, at 66 (1990).

Consistent with our disallowance of $6,685,376 in plant additions from rate base as discussed above, the Department must adjust the Company's deferred income taxes to remove the deferred income taxes associated with the disallowed plant. D.P.U. 10-55, at 194; The Berkshire Gas Company, D.T.E. 01-56, at 42 (2001). In view of the complexities associated with deferred income tax calculations, the Department will derive a representative level of associated deferred income taxes for ratemaking purposes by dividing the plant-related deferred income taxes of $181,497,988 by the Company's total net utility plant as of December 31, 2014, of $650,528,325 (Exhs. NSTAR-MFF-5, WP MFF-30 (August 21, 2015) (excluding 2014); NSTAR-MFF-2, Sch. MFF-27 (August 21, 2015)). D.P.U. 13-90, at 61; D.P.U. 10-55, at 194; D.T.E. 01-56, at 43. This produces a factor of 27.9 percent which, when multiplied by the total net plant excluded from rate base of $6,685,376, produces a deferred income tax balance of $1,865,219. Accordingly, the Department reduces the Company's proposed deferred income tax reserve by $1,865,219, resulting in total accumulated deferred income taxes of $175,392,592.

F. Contributions in Aid of Construction

1. Introduction

Contributions in aid of construction ("CIAC") are defined as donations or contributions in cash, services, or property from states, municipalities or other governmental agencies, individuals, and others for construction purposes. See USOA-Gas, Balance Sheet Accounts, Assets and Other Debits, §12, Account 271, Contributions in Aid of Construction, ¶ A. NSTAR Gas does not book CIAC to Account 271, Contributions in Aid of Construction, in the manner prescribed by the Department.[74] Instead, the Company credits CIAC received from customers or developers related to capital projects to Account 107, Construction Work in Progress, against the cost of construction[75] (Exhs. DPU-3-9; DPU-5-3, Att.). The Company states that this accounting method is consistent with the method currently prescribed by the Federal Energy Regulatory Commission ("FERC") (Tr. 1, at 46-47). Further, the Company states that its accounting treatment of CIAC is consistent with how its affiliates in jurisdictions outside of Massachusetts treat CIAC (Tr. 1, at 45-47, 49).

NSTAR Gas reports that it has booked $4,634,529 in CIAC against work orders since January 2005 (Exh. DPU-5-3, Att. at 27; Tr. 1, at 44-45). As of the end of the test year, the Company had a zero balance in Account 271 (Exh. DPU-3-9; Tr. 1, at 43). No party addressed the Company's accounting treatment of CIAC on brief.

2. Analysis and Findings

Under longstanding Department practice, property that has been contributed to a utility is not included in rate base. Milford Water Company, D.P.U. 771, at 21; Oxford Water Company, D.P.U. 18595, at 18 (1976); Commonwealth Gas Company, D.P.U. 18545, at 2 (1976). This ratemaking treatment is because the utility is not entitled to a return on investment that was paid for by customers; otherwise, ratepayers would end up paying twice for the same plant – once through the contribution, and again through a return of and on the plant through depreciation and

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74 NSTAR Gas states that it has not booked CIAC to Account 271 since some time prior to 1984 (Exh. DPU-5-3).

75 Once a capital project is completed, project costs booked to Account 107 are redistributed among the detailed plant accounts. USOA-Gas, Balance Sheet Accounts, Assets and Other Debits, Account 107.

return on rate base. D.P.U. 771, at 21-22; D.P.U. 18595, at 7-8; D.P.U. 18545, at 2-4. Consistent with this policy, the Department has not permitted depreciation expense on contributed property. D.P.U. 84-32, at 18-20, citing Hingham Water Company, D.P.U. 1590, at 22-23 (1984).

General Laws c. 164, § 81, requires gas and electric companies to maintain their books and accounts in a manner prescribed by the Department. The need to ensure accounting uniformity, as well as to facilitate the Department's ability to exercise its general supervisory authority over the industries that it regulates, warrants the adoption of a standardized system of accounts for the companies subject to this agency's jurisdiction. D.P.U. 08-35, at 43-44; Aquaria LLC, D.T.E. 04-76, at 21 (2005); Reclassification of Accounts of Gas and Electric Companies, D.P.U. 4240-A, Introductory Letter (May 19, 1941); Reclassification of Accounts of Gas and Electric Companies, D.P.U. 104, Introductory Letter (May 27, 1921); Second Annual Report of the Board of Gas Commissioners, 2 Ann. Rep. Mass. Gas Comm. (1887) 61, App. B. The Department has long prescribed its own accounting system for gas companies in the form of the USOA-Gas and its predecessors. 220 C.M.R. § 50.00 et seq.[76]

Account 271 specifies that this account "shall include donations or contributions in cash, services, or property from states, municipalities or other governmental agencies, individuals, and others for construction purposes." 220 C.M.R. §§ 50.00 et seq., Uniform System of Accounts for Gas Companies, Balance Sheet Accounts, Assets and Other Debits, §12, Account 271,

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76 The Department has adopted the Uniform System of Accounts for Electric Companies prescribed by the FERC with several modifications. 220 C.M.R. § 51.01(1). The Department, however, has not adopted FERC's Uniform System of Accounts for Gas Companies. 220 C.M.R. § 50.00 et seq.

Contributions in Aid of Construction, ¶ A. The associated instructions contained in the USOA-Gas are unambiguous on this point:

> Gas plant contributed to the utility or constructed by it from contributions to it of cash or its equivalent shall be charged to the gas plant accounts at cost of construction, estimated if not known. There shall be credited to the accounts for reserves for depreciation and amortization the estimated amount of depreciation and amortization applicable to the property at the time of its contribution to the utility. The difference between the amounts included in the electric plant accounts and the amounts credited to the reserves for depreciation and amortization shall be credited to Account 271, Contributions in Aid of Construction.

220 C.M.R. §§ 50.00, Uniform System of Accounts for Gas Companies, Gas Plant Instructions; § 2.E.

Under this instruction, CIAC, whether in the form of contributed property or cash received for construction, is added to the plant account, and any accumulated depreciation associated with CIAC in the form of contributed property accrued up to the time the associated property is transferred to the utility is booked to the depreciation reserve account. The remaining difference is booked to Account 271. Notwithstanding NSTAR Gas' desire for uniformity among companies operating under the Northeast Utilities umbrella, the Department's accounting regulations, not those of jurisdictions outside of Massachusetts or the federal government, govern the Company's operations in Massachusetts. The Department has consistently required that CIAC be booked to Account 271 to ensure accounting transparency for ratemaking purposes. D.P.U. 12-25, at 114-114; D.P.U. 08-35, at 44-45; <u>New England Gas Company</u>, D.P.U. 07-46, at 9 (2007). Therefore, to ensure uniform accounting treatment among all gas companies, the Department directs NSTAR Gas to maintain CIAC as a separate account consistent with the USOA-Gas.

The Department acknowledges that because the Company's accounting practice has been longstanding, it may be difficult to identify and locate all of the work orders recording CIAC (Tr. 1, at 50-51). Moreover, some portion of the CIAC may be associated with plant that has now been retired (Tr. 1, at 50-51). In recognition of the difficulty that would be associated with extracting CIAC balances from the Company's plant accounts and determining what portion was associated with plant that remains in service, the Department will not require NSTAR Gas to adjust its plant accounts for all CIAC received by the Company. Instead, the Department directs NSTAR Gas to debit its plant in service accounts by those CIAC received since January 1, 2005. The Company shall credit Account 271 by the sum of $4,634,529, plus all CIAC received since the end of the test year (see Exh. DPU-5-3, Att. at 27). The Company shall distribute the $4,634,529 among the accounts listed in Exhibit DPU-5-3, and shall distribute all CIAC received since the end of the test year to those respective plant accounts. The Company is further directed to provide the Department with the related journal entries within 30 days of the date of this Order. Finally, the Department directs NSTAR Gas to revise its booking of depreciation expense to ensure that no depreciation is taken on CIAC. Milford Water Company, D.P.U. 84-135, at 32-33 (1985). D.P.U. 84-32, at 18 20; D.P.U. 1590, at 22-23.

V. REVENUES

A. Weather Normalization and Annualization Adjustments

1. Introduction

NSTAR Gas proposes a weather normalization adjustment to its test year sales volumes and revenues to adjust each to what it likely would be under the weather conditions that typically occur during the year (Exh. NSTAR-RDC-1, at 5, 6). Because the weather was colder than normal in the test year, the Company proposes to decrease its test year distribution revenues by $1,481,891, which represents the difference between actual test year sales volumes and weather normalized sales volumes, applied to the current base rates (Exhs. NSTAR-RDC-1, at 6, 7; NSTAR-RDC-2, Sch. RDC-3, at 1).

In determining its proposed weather normalization adjustment, the Company identified rate classes with sales volumes that are temperature sensitive (i.e., residential heating and commercial and industrial ("C&I") classes with low load factors) (Exh. NSTAR-RDC-1, at 7, 8).[77] For these rate classes, the Company determined the temperature sensitive portion of their sales volumes and calculated the monthly difference between actual sales volumes and sales volumes that would have occurred if temperatures had been normal during the test year (Exh. NSTAR-RDC-1, at 7, 8).

The Company also proposes an annualization adjustment of $557,505 to test year revenues to account for the sales volume and revenue changes caused by: (1) customer use in one month that is not billed until the following month (i.e., a calendar month adjustment); and (2) the occurrence of a leap year every four years (i.e., a billing day adjustment) (Exhs. NSTAR-RDC-1, at 13-18; NSTAR-RDC-2, Sch. RDC-3, at 1). In determining its proposed calendar month adjustment, the Company extracted test year monthly billing volumes from its customer information system and revised this data for adjustments to customer bills that were made during the test year, resulting in a reduction of 22,637 therms (or a 0.1 percent) to test year monthly billing volumes (Exh. NSTAR-RDC-1, at 5).

[77] The residential heating classes include R-3 and R-4. The C&I low load factor rate classes include G-41, G-42, and G-43 (Exh. NSTAR-RDC-1, at 7).

Next, the Company converted the sales volumes collected and stored in the customer information system on a billing-cycle basis, to a calendar-month basis, by calculating, for each rate class, unbilled therms using effective degree day factors.[78] To do this, the Company subtracted the portion of gas use in each monthly billing cycle that occurred for days prior to the calendar month, from the total use for the calendar month, using each rate class' base load use and use per effective degree day factors (Exh. NSTAR-RDC-1, at 10-11). Then, the Company added to total gas use in a calendar month, the portion of gas use from each billing cycle that occurred for days subsequent to the calendar month, using each rate class' base load use and use per effective degree day factors (Exh. NSTAR-RDC-1, at 10-11). These calculations result in a proposed calendar month adjustment of $525,377 (Exhs. NSTAR-RDC-1, at 16; NSTAR-RDC-2, Sch. RDC-3, at 1).

As noted above, a billing day adjustment is intended to account for the difference between the actual number of billing days in the test year (i.e., 365) and the number of billing days in a normal year (i.e., 365.25, to recognize the occurrence of a leap year every four years) (Exh. NSTAR-RDC-1, at 13). To determine its proposed billing day adjustment, the Company multiplied the ratio of normal calendar days (i.e., 28.25) to test year calendar days in February (i.e., 28), by total calendar use per customer in that month, to derive the incremental use per customer arising from an extra 0.25 day (Exh. NSTAR-RDC-1, at 13-14). The Company then multiplied this incremental use by the number of customers in February 2013 to arrive at a total

78 Effective degree days is a means of expressing the correlation between various weather conditions and heating requirements by adjusting heating degree days to factor in wind speed (Exh. NSTAR-RDC-1, at 6).

volume adjustment of 170,189 therms and a resulting proposed billing day adjustment of $32,128 (Exhs. NSTAR-RDC-1, at 14, 16; NSTAR-RDC-2, Sch. RDC-3, at 1).

2. Positions of the Parties

a. Attorney General

The Attorney General contends that billing determinants, when not properly normalized, can result in a shift in cost recovery from one rate class to other rate classes, and result in rates that will either under- or over-collect their revenue requirement (Attorney General Brief at 68). The Attorney General does not agree with NSTAR Gas' determination that it is unnecessary to weather normalize high load factor rate class billing determinants (Attorney General Brief at 68; Attorney General Reply Brief at 36). The Attorney General argues that there is evidence of some weather sensitivity for these classes and notes that the Company conceded that high load factor customers have some winter-sensitive heating load (Attorney General Brief at 69, citing Tr. 4, at 324; Tr. 9, at 831-832). In addition, the Attorney General argues that once base load usage levels are removed from class usage, the remaining load variation is consistent with the same level of degree day variation exhibited by the heating classes (Attorney General Brief at 68-69, citing Exh. AG-RSB-6, Table 8). The Attorney General asserts that a high degree of correlation (in most cases in excess of 95 percent) exists between non-base load volumes and weather (Attorney General Brief at 69, citing Exh. AG-RSB-6, at 4-5).

The Attorney General notes that adjusting high load factor class usage for weather may appear "trivial" when 2013 data are used (0.8 percent warmer than normal) (Attorney General Reply Brief at 36). She argues, however, that when data from 2014 are examined (a colder than normal year), the normalized volumes yield a more significant 3.6 percent reduction in billing determinants (Attorney General Reply Brief at 36, citing Exh. AG-RSB-6, at 3-6). The Attorney General contends that the Company failed to recognize the magnitude of the adjustment to the high load factor classes based on 2014 data (Attorney General Reply Brief at 36). According to the Attorney General, this omission will result in inefficient rates for these classes (i.e., the Company will under-collect base revenues for high load factor classes by using inflated volumes) (Attorney General Reply Brief at 36). Further, the Attorney General claims that the resulting base revenue deficiency will be recovered in the decoupling adjustment from all C&I customers (Attorney General Reply Brief at 36-37).

To remedy these issues, the Attorney General recommends that NSTAR Gas be required to weather normalize high load factor rate classes because the Company has failed to demonstrate that non-base load uses do not exhibit variation consistent with variation in temperatures (Attorney General Brief at 70). In this regard, the Attorney General asserts that the Company should use 2014 normalized usage for all rate classes as the basis for normalized revenues and billing determinants to design rates (Attorney General Brief at 70, citing Exh. AG-22-1; Attorney General Reply Brief at 37).

b. TEC

TEC supports the Attorney General's recommendation to weather-normalize the high load factor rate classes (TEC Reply Brief at 4). TEC notes that the Attorney General's statistical analysis shows that a high degree of correlation exists between weather and the usage for the high load factor rate classes (TEC Reply Brief at 4, citing Attorney General Brief at 69). TEC warns that billing determinants that are not properly normalized can result in a cost-recovery shift among rate classes which, in turn, will either over- or under-collect their revenue requirement (TEC Reply Brief at 4).

c. Company

The Company argues that its proposed approach to weather normalization is consistent with Department precedent and should be approved (Company Brief at 194; Company Reply Brief at 56, citing D.P.U. 13-75, at 137). The Company does not agree with the Attorney General's recommendation to weather-normalize the high load factor rate classes (Company Brief at 194). The Company contends that the Attorney General's statistical analysis does not demonstrate causality between non-base loads and weather (Company Brief at 194; Company Reply Brief at 57). Rather, the Company argues that the Attorney General's statistical analysis merely establishes a relationship between temperature and heating use (Company Brief at 194, citing Tr. 9, at 831). The Company asserts that the existence of a correlation between two variables does not imply causality (Company Reply Brief, at 57, citing Tr. 9, at 832). Further, the Company contends that weather normalization is based on the assumption that a linear relationship exists between usage and effective degree days (Company Brief at 194). The Company argues that the Attorney General's analysis does not show exactly how temperatures impact gas use for high load factor customers which are typically process-oriented (Company Brief at 194, citing Tr. 9, at 831-832).

In addition, the Company argues that the Attorney General mischaracterizes the evidence regarding the weather normalization of high load factor rate class billing determinants (Company Reply Brief at 57, citing Attorney General Reply Brief at 36). In this regard, the Company contends that the Attorney General improperly calculated the impact of weather on billing determinants using 2014 data and, therefore, overstated the alleged reduction in billing determinants (Company Brief at 57-58, citing Exh. AG-22-1). Rather, NSTAR Gas asserts that a proper use of 2014 data produces only a 0.4 percent reduction in billing determinants across all rate classes when compared to the Company's proposal (Company Reply Brief at 58, citing RR-DPU-18).

Based on the above, the Company argues that the Attorney General has failed to show how temperatures impact gas usage for high load factor customers sufficient to require the weather normalization of billing determinants for these customers (Company Reply Brief at 58). Moreover, the Company contends that the Department has not required all gas distribution companies to weather-normalize billing determinants for their high load factor customers (Company Brief at 194, citing D.P.U. 13-75). Accordingly, the Company asserts that the Attorney General's recommendation should be denied (Company Brief at 194; Company Reply Brief at 58).

3. Analysis and Findings

The Department's standard for weather normalization of test year revenues is well established. See D.T.E. 03-40, at 22; D.P.U. 96-50 (Phase I) at 36-39; D.P.U. 93-60, at 75-80. The Attorney General challenges the Company's proposed weather normalization adjustment because NSTAR Gas failed to weather normalize use for high load factor customers. In reviewing the Attorney General's recommendations and her statistical analysis shown in Exhibit AG-RSB-7, the Department does find that there is a correlation between the weather and non-base load usage for high load factor customers. The Attorney General's analysis, however, does not demonstrate that the change in weather is the cause for the change in non-base load usage for high load factor customers (Exh. AG-22-1; Tr. 9, at 830-832). The Department has not previously required gas distribution companies to weather-normalize sales for high load factor customers. See D.P.U. 13-75, at 137; D.P.U. 11-01/D.P.U. 11-02, at 166; D.P.U. 10-55, at 214-215. Given insufficient evidence of causation, we find that departure from this precedent is not warranted here. Accordingly, we will not require the Company to weather-normalize high load factor usage.

After review, the Department finds that the Company's proposed method to weather normalize test year sales and revenues, as described above, is consistent with Department precedent. Accordingly, the Department approves the Company's proposal to decrease test year revenues by a weather normalization adjustment of $1,481,891 to account for colder than normal weather in the test year.

The Department has historically permitted adjustments for unbilled revenues, which account for discrepancies between sales volumes based on billing cycles and sales volumes based on calendar months. D.T.E. 03-40, at 12. Further, the Department has consistently allowed for billing day adjustments to test year sales volumes and revenues to reflect the fact that a normal year consists of 365.25 days. See, e.g., D.P.U. 13-75, at 137; D.T.E. 03-40, at 9. The Department finds that the Company's proposed adjustments to test year sales volumes and revenues to account for the calendar month and billing day adjustments, as described above, are consistent with Department precedent. Accordingly, the Department approves the Company proposal to increase test year revenues by a total annualization adjustment of $557,505 (i.e., a calendar month adjustment of $525,377 plus a billing day adjustment of $32,128).

VI. OPERATIONS AND MAINTENANCE EXPENSES

A. Base Rate Freeze and Merger-Related Costs and Savings

1. Introduction

a. D.P.U. 10-170-B

As noted above in Section IV.B.6.c, in D.P.U. 10-170-B the Department approved a rate freeze applicable to the Company's base distribution rates until January 1, 2016. D.P.U. 10-170-B, at 36, 39-41. Further, Article II (14) of the Merger Settlement provided that "[s]ubject to Department review and approval, transaction and reasonable integration costs from the [p]roposed [m]erger shall be eligible for recovery in a future distribution rate proceeding through the retention of merger-related synergies to the extent that merger-related savings are demonstrated to equal or exceed those costs." In addition, Article II (15) of the Merger Settlement provided that "[f]or ratemaking purposes, [NSTAR Gas] shall amortize merger-related transaction and integration costs over a [ten]-year period following the approval of the proposed settlement agreement." Finally, Article II (15) of the Merger Settlement required the Company to provide interim reports regarding merger costs and savings.

In the Order approving the settlements, the Department also addressed the issue of projected net savings. D.P.U. 10-170-B at 53-58. The Department noted that to support their claim that the proposed merger would result in net savings the joint petitioners conducted a Net Benefits Study. D.P.U. 10-170-B at 53. The Net Benefits Study forecasted net merger-related savings for the ten years following the merger, with a total estimate of $784 million in net savings enterprise-wide. D.P.U. 10-170-B at 53. The Department found that the joint petitioners' reliance on the Net Benefits Study to forecast net merger-related savings was reasonable. D.P.U. 10-170-B at 57-58. Further, the Department found that the provision of Article II (14) of the Merger Settlement authorizing the Company to seek recovery of merger-related costs was consistent with Department precedent. D.P.U. 10-170-B at 60, citing D.P.U. 09-39, at 276; Bay State Gas Company/Unitil Corporation, D.P.U. 08-43-A at 44-45 (2008).

b. Reported Merger-Related Savings and Costs

On October 10, 2014, pursuant to the Merger Settlement, NSTAR Gas submitted a merger report to the Department, Attorney General, and DOER detailing its merger-related efforts from 2010 through 2013 ("2013 Merger Report") (Exhs. NSTAR-EHC-1, at 9; NSTAR-EHC-2). According to the Company, the 2013 Merger Report shows that enterprise-wide net savings over the ten-year period following the merger are expected to be $876.7 million, a more than $92.0 million increase in the amount initially forecasted in the Net Benefits Study (Exhs. NSTAR-EHC-1, at 10; NSTAR-EHC-2, at 7). The Company's allocated share of these total savings is $52.3 million (Exhs. NSTAR-EHC-1, at 10; NSTAR-EHC-2, at 7; NSTAR-EHC-3). NSTAR Gas reports that savings through the end of the test year on an enterprise-wide basis were $44.8 million and that the Company's allocated share of these savings was $2.7 million (Exhs. NSTAR-EHC-1, at 11; NSTAR-EHC-2, at 7; NSTAR-EHC-3). The Company also states that in October 2012, $3.0 million was paid to NSTAR Gas customers pursuant to the Merger Settlement (Exh. NSTAR-EHC-1, at 10; see also Merger Settlement, Art. II (2)).

Finally, NSTAR Gas reports that merger-related costs from 2010 to 2013 totaled $113.8 million enterprise-wide (Exhs. NSTAR-EHC-1, at 12; NSTAR-MFF-5, WP MFF-22, at 3

(August 21, 2015)). The Company's share of these costs was equal to $4,847,546, or approximately 4.26 percent of total costs (Exhs. NSTAR-EHC-1, at 12; NSTAR-EHC-2, at 7; NSTAR-EHC-3; NSTAR-MFF-5, WP MFF-22, at 3 (August 21, 2015)).

As discussed further below, NSTAR Gas proposes to recover merger-related costs because the Company contends that its share of merger-related savings exceeds its share of merger-related costs. In this regard, NSTAR Gas proposes to amortize its allocated share of the 2010 through 2013 merger-related costs over ten years beginning April 10, 2012 (Exh. NSTAR-EHC-1, at 12). Thus, the Company proposes an amortization expense of $484,755 in its revenue requirement (Exh. NSTAR-EHC-1, at 12; NSTAR-MFF-5, WP MFF-22, at 3 (August 21, 2015)).

2. Positions of the Parties

a. Attorney General

i. Base Rate Freeze

The Attorney General argues that the Company's proposal to use a 2013 test year with pro forma adjustments conflicts with the rate freeze approved in D.P.U. 10-170-B, is an inappropriate basis for setting base rates, and is inconsistent with Department policy that prohibits companies from deferring costs from the rate freeze period for later recovery (Attorney General Brief at 85, citing Exh. AG-AP-1, at 9; D.P.U. 14-135, at 142; NSTAR Pension, D.T.E. 03-47-A at 33 (2003); North Attleboro Gas Company, D.P.U. 93-229 (1994)). The Attorney General acknowledges that pro forma adjustments, as opposed to dollar-for-dollar deferrals, are used as representative costs to set rates for future application, but she argues that this distinction does not favor allowing pro forma adjustments during a rate freeze period (Attorney General Brief at 85). According to the Attorney General, if the Company knows that a pro forma adjustment that reduces the cost of service would, likewise, reduce rates until they are reset in the future, then the Company would be discouraged from seeking merger savings beyond the amount that the Department recognizes as an offset to merger costs after the test year (Attorney General Brief at 86).

Further, while the Attorney General concedes that the Department's Order in D.P.U. 10-170-B is silent as to the ratemaking treatment to be used for pro forma adjustments based on costs incurred during the rate freeze period, she urges the Department not to apply its ratemaking discretion in such a way as to provide an incentive for merged companies to be inefficient, especially in this instance where the Company's 2013 test year and request for pro forma adjustments through the rate-year ending July 1, 2016, encompasses almost the entire 44-month rate freeze period that began in 2012 (Attorney General Brief at 86, citing Petition at 4; D.P.U. 10-170-B at 36). In this regard, the Attorney General asserts that the Department should not allow any pro forma adjustments to the test year cost of service because it will undermine incentives for economic efficiencies that may be available through mergers (Attorney General Brief at 86).

ii. Merger-Related Costs and Savings

The Attorney General argues that if the Department does not accept her recommendation to disallow all pro forma adjustments to the Company's test year cost of service, then it should adjust test year O&M expenses to reflect known and measurable merger savings that will be experienced during the rate year (Attorney General Brief at 86-87, citing Exhs. AG-DJE-1, at 27-29; AG-15-6; Attorney General Reply Brief at 8). The Attorney General argues that based on the 2013 Merger Report, the rate year merger-related savings allocated to NSTAR Gas will exceed the test year merger-related savings by $1,710,518 (Attorney General Brief at 87, citing Exh. AG-DJE-Rebuttal-1, Sch. DJE-R-6). Accordingly, the Attorney General recommends that the Department reduce the Company's test year cost of service by $1,710,518 to account for the additional known and measurable merger-related savings (Attorney General Brief at 87).

In support of her recommendation, the Attorney General argues that the growth in merger-related savings from 2013 to 2016 is attributable to more than just inflation and, therefore, should be factored into the Company's revenue requirement (Attorney General Reply Brief at 8-9, citing Tr. 13, at 1121-1122). Further, the Attorney General contends that her proposed adjustment properly accounts for the Company's adjustment to its cost of service for labor reductions in the information technology department (Attorney General Reply Brief at 9). The Attorney General notes that the Company's purported "deduction" from its cost of service for this expense actually results in an increase to the overall cost of service (Attorney General Reply Brief at 9, citing Company Brief at 26). Thus, she asserts that there are no savings associated with this adjustment (Attorney General Reply Brief at 9). Finally, the Attorney General argues that the cases cited in support of the Company's contention that its revenue requirement should not be adjusted to reflect merger-related savings are distinguishable from the circumstances in the instant case (Attorney General Reply Brief at 9-10, citing D.P.U. 09-39, at 277-278; D.P.U. 08-43-A at 45).

Based on the above, the Attorney General asserts that if the Department finds that the 2013 Merger Report justifies the recovery of merger-related costs, then the Department should reduce the Company's proposed O&M expense by $1,710,518 to incorporate the merger savings that she maintains will be experienced by NSTAR Gas in the rate year and beyond (Attorney General Brief at 87; Attorney General Reply Brief at 10-11). Alternatively, the Attorney General asserts that if the Department finds that the merger-related savings set forth in the 2013 Merger Report are not known and measurable, then the Company has not justified the recovery of any merger-related costs (Attorney General Reply Brief at 10).

b. DOER and TEC

i. Base Rate Freeze

DOER and TEC argue that the Merger Settlement required the Company to freeze its base rates in effect on January 1, 2012, through December 31, 2015 (DOER Brief at 5; TEC Reply Brief at 6). DOER and TEC contend that beginning in April 2012, NSTAR Gas began capitalizing internal labor related to the Company's information technology projects, including contracted labor resources (DOER Brief at 5, citing Exh. AG-16-4, Att. (a) at 25; TEC Reply Brief at 6). According to DOER and TEC, the change in treatment of the information technology-related labor expenses allows the Company to recover costs incurred during the base rate freeze through the rates established in this proceeding, as these expenses now are included in the Company's rate base (DOER Brief at 5-6; TEC Reply Brief at 6). DOER and TEC argue that the change in treatment of the information technology-related labor expenses is inconsistent with the rate freeze in D.P.U. 10-170, which prevents the Company from recovering in a future base rate case any expenses incurred during the rate freeze, except for certain exogenous costs (DOER Brief at 4-5, citing Exh. AG-16-8; Tr. 7, at 567-571; TEC Reply Brief at 6). Accordingly, DOER and TEC assert that the Department should require the

Company to recalculate its test year capital expense using the capitalization policy in effect on the date of the Merger Settlement (DOER Brief at 6; TEC Reply Brief at 6).

ii. Merger-Related Costs and Savings

DOER argues that the Company's reported merger-related costs and savings should be accepted by the Department (DOER Brief at 2-4). DOER contends that although some evidence suggests that there has been no downward trend in the Company's O&M expenses since the D.P.U. 10-170 merger, the lack of a decline in expenses can be attributed to a significant increase in the Company's workload, coupled with the need to address employee attrition (DOER Brief at 4, citing Exh. AG-AEP-1, at 13-14, 16-17; Tr. 1, at 24-27). DOER contends that without merger savings, O&M costs would have been even higher due to these factors (DOER Brief at 4). Finally, DOER notes that no party has challenged the 2013 Merger Report and that evidence shows that actual merger-related savings are on track with projected savings (DOER Brief at 3, 4, citing Exh. NSTAR-EHC-2). Accordingly, DOER asserts that the Company should be allowed to recover its merger-related costs (DOER Brief at 4).

DOER and TEC also agree with the Attorney General that if the 2013 Merger Report is found appropriate to warrant the recovery of merger-related costs, then the Company's revenue requirement should be adjusted to account for merger-related savings in the rate year and beyond (DOER Brief at 4-5; TEC Reply Brief at 6). In this regard, DOER supports the Attorney General's recommendation to reduce the Company's proposed O&M expense by $1,710,518 to incorporate the merger savings that she contends will be experienced in the rate year (DOER Brief at 5, citing Exh. AG-DJE-1, at 28; AG-DJE-Rebuttal-1, Sch. DJE-R-6; Tr. 13, at 1119, 1144-1147).

c. Company

i. Base Rate Freeze

Contrary to the Attorney General's assertions, the Company argues that it is not seeking to defer for later recovery expenses incurred during the rate freeze period (Company Brief at 22; Company Reply Brief at 38). Rather, NSTAR Gas argues that the rates that go into effect on January 1, 2016, are designed to collect a revenue requirement to cover costs that are expected to be incurred as of January 1, 2016, and beyond (Company Brief at 22; Company Reply Brief at 38). The Company argues, therefore, that it will not recover any expenses actually incurred and recorded on its books during the rate freeze period (Company Brief at 22; Company Reply Brief at 38).

Further, NSTAR Gas disagrees with the Attorney General regarding the effect of pro forma adjustments to test year expenses (Company Brief at 23-24; Company Reply Brief at 37-38). NSTAR Gas argues that while the rate freeze prevents it from recovering increased expenses during the rate freeze period, there is no ratemaking principle that would prevent the Company from recovering the actual cost of service to customers based on costs that have increased during the rate freeze period (Company Brief at 23-24). Thus, the Company asserts that in determining representative costs for the purpose of setting new rates, it is appropriate to consider any increases in expenses that occurred during the rate freeze period (Company Brief at 24). NSTAR Gas contends that nothing in the settlement agreements or in D.P.U. 10-170-B supports the Attorney General's position on this point (Company Brief at 23, 24; Company Reply Brief at 37-38).

ii. Merger-Related Costs and Savings

NSTAR Gas argues that it has demonstrated that merger-related savings equal or exceed merger-related costs and, therefore, the Company is entitled to recover its proposed merger-related costs (Company Brief at 20-21; Company Reply Brief at 35-37). Specifically, NSTAR Gas contends that because its ratepayers received an upfront payment of $3.0 million, which represented a share of future cost savings resulting from the D.P.U. 10-170 merger, the Company needs to show additional savings of only $1.85 million, or $185,000 annually over the ten-year amortization period, to be eligible to recover $4.85 million in merger-related costs (Company Brief at 20-21; Company Reply Brief at 35-36). In this regard, NSTAR Gas claims that the 2013 Merger Report indicates that the Company's share of net savings achieved through the end of the test year is $2.7 million (Company Brief at 20-21, citing Exhs. NSTAR-EHC-2, at 4; NSTAR-EHC-3; Company Reply Brief at 36). Further, the Company argues that it has provided specific examples of annual savings in excess of $185,000, such as employee-benefit cost savings that are directly attributable to the merger (Company Brief at 21, citing Exh. DPU-6-13; Company Reply Brief at 36).

NSTAR Gas disagrees with the Attorney General, DOER, and TEC regarding the propriety of adjusting the Company's cost of service to account for merger savings that will be experienced in the rate year (Company Brief at 24-27; Company Reply Brief at 34-44). First, the Company argues that the 2013 Merger Report is designed only to quantify and demonstrate total enterprise savings in order to show that the merger was beneficial to customers (Company Brief at 24-25; Company Reply Brief at 38-39). NSTAR Gas insists that the 2013 Merger Report should not be used as a proxy for the Company's actual cost of service (Company Brief at 25, citing Exh. AG-15-8).

Second, the Company argues that actual operating cost reductions associated with the merger were completed in 2014 (Company Brief at 25, citing Tr. 2, at 110). The Company contends that the savings for 2016, as shown in the 2013 Merger Report, represent: (1) avoided inflation associated with operating costs that were eliminated in prior years; (2) avoided revenue requirement associated with capital additions that were avoidable due to labor reductions; and (3) additional staffing reductions occurring after 2013 to implement the revised information technology organizational model (Company Brief at 25, citing Exh. NSTAR-EHC-2, at 20). Thus, NSTAR Gas claims that, other than changes related to its implementation of a revised information technology organizational model which are fully captured in the proposed revenue requirement, there are no incremental O&M reductions occurring in 2015 or 2016 (Company Brief at 25; Company Reply Brief at 41). As a result, NSTAR Gas asserts that the Attorney General's recommended reduction to the Company's proposed revenue requirement of $1,710,518 would double count savings already factored into rates (Company Brief at 25; Company Reply Brief at 41).

Third, the Company takes issue with the Attorney General's calculation of her recommended revenue requirement reduction (Company Brief at 26; Company Reply Brief at 39-41). According to the Company, the Attorney General failed to properly account for the adjustments it made to cost of service for information technology changes that occurred in 2014 and the avoided inflation associated with those changes[79] (Company Brief at 26, citing Exh. AG-Rebuttal-DJE-1, Sch. DJE-R-6; Tr. 13, at 1146-1147; Company Reply Brief at 39-40). The Company maintains that accounting for these factors would reduce the amount of the Attorney General's recommended revenue requirement reduction (Company Brief at 26, citing Tr. 13, at 1146-1147; Company Reply Brief at 39-40, citing Exhs. NSTAR-MFF-1, at 24-25; NSTAR-MFF-2, Sch. MFF-9 (June 15, 2015); NSTAR-MFF-5, WP MFF-9 (June 15, 2015)).

Finally, the Company argues that the Department has previously rejected proposed adjustments to reflect future savings where merger-related savings achieved and merger-related costs incurred through the test year already are incorporated into cost of service (Company Brief at 26, citing D.P.U. 09-39, at 277-278; Company Reply Brief at 41-42). According to the Company, where additional savings will occur after the test year and there is no recovery of an acquisition premium from customers, it is not appropriate to incorporate future savings in the revenue requirement (Company Brief at 26; Company Reply Brief at 42). In this regard, NSTAR Gas disagrees with the Attorney General's interpretation of the Department's findings in D.P.U. 09-39 and D.P.U. 08-43-A; the Company claims that the policies set forth in these decisions provide only that merger-related savings are to be incorporated in a future base rate filing (Company Brief at 26-27, citing D.P.U. 09-39, at 277-278; D.P.U. 08-43-A at 45; Company Reply Brief at 42-43).

[79] NSTAR Gas asserts that the evidence demonstrates that the 2014 savings are included in its proposed cost of service (Company Reply Brief 40-41, citing Exhs. NSTAR-MFF-2, Sch. MFF-9 (June 15, 2015); NSTAR-MFF-5, WP MFF-9 (June 15, 2015); DPU-14-11; Tr. 2, at 125-126; Tr. 13, at 1146-1147).

3. Analysis and Findings

a. Base Rate Freeze

As a result of the aforementioned merger, the Company's base rates are frozen until January 1, 2016. D.P.U. 10-170-B at 36, 39-41. The Attorney General argues that because of the rate freeze, the Department should not allow any pro forma adjustments to the Company's cost of service (Attorney General Brief at 85-86). We disagree.

A base rate freeze is intended to benefit ratepayers by providing rate certainty for a certain period of time. See, e.g., NEES/EUA Merger, D.T.E. 99-47 (2000) (five-year freeze); BEC Energy/Commonwealth Energy Systems, D.T.E. 99-19, at 23 (1999) (four-year freeze); Eastern/Colonial Acquisition, D.T.E. 98-128 (1999) (ten-year freeze); NIPSCO/Bay State Acquisition, D.T.E. 98-31 (1998) (five-year freeze); Eastern/Essex Acquisition, D.T.E. 98-27 (1998) (ten-year freeze)). That is, base rates cannot increase for the duration of the rate freeze. A rate freeze, however, does not guarantee that a company's underlying costs will not increase or decrease during the rate freeze period.

During a rate freeze, a company is responsible for absorbing any increased costs because (other than an exogenous cost provision, if it is part of the rate freeze) a company has no mechanism to recover incremental expenses actually incurred and recorded on its books during that period. There is no general ratemaking principle, however, that would prevent a company from petitioning the Department to establish new rates upon expiration of a rate freeze, based on the actual level of expenses experienced during the rate freeze.

In the instant case, NSTAR Gas' requested rate increase is based on a 2013 test year (Exh. NSTAR-MFF-1, at 3). The Company offers pro forma adjustments to test year cost of service to propose what it contends is the representative level of expense it will incur after January 1, 2016 (see, e.g., Exhs. NSTAR-MFF-1, at 3; NSTAR-MFF-2, Sch. MFF. 6, at 1 (August 21, 2015)). The new rates approved in this Order, although based on known and measurable changes to test year expenses that occurred during the rate freeze, are designed to recover a representative level of expenses that the Company expects to incur in the future, after expiration of the rate freeze. With the exception of certain information technology-related labor costs, discussed below, the new rates will not permit the Company to recover any costs incurred during the rate freeze in the rates established in this Order. Accordingly, the Department finds that it is appropriate to use the Company's test year 2013 cost of service, with all required adjustments, to establish rates in this proceeding.

Finally, DOER and TEC contend that the Company's change in the accounting treatment of information technology-related labor costs allows NSTAR Gas to inappropriately recover costs that would have been expensed during the rate freeze but, instead, were capitalized and included as part of the rate base used to establish rates in this Order (DOER Brief at 5-6; TEC Reply Brief at 6). Accordingly, DOER and TEC assert that the Company should be required to exclude the information technology-related investment from rate base (DOER Brief at 6; TEC Reply Brief at 6).

The Company modified its accounting policy standard for computer software purchased or developed for internal use and made the revised policy applicable to projects placed in service after April 1, 2012 (Exh. AG-16-4, at 2 & Att. (b)).[80] Specifically, the revised standard provides

80 The Company states that it revised its accounting policy to conform with Northeast Utilities' policy (see Exh. AG-16-4, at 2 & Att. (b)).

that internal and external costs associated with such software are capitalized where the expected costs of the project are $100,000 or more (Exh AG-16-4, Att. (b) at 1).[81] Moreover, for employees working on a capital job, the operations internal labor is included as part of the cost of the capital job (Tr. 7, at 568).[82]

DOER and TEC correctly observe that, but for the change in accounting policy, the information technology-related labor costs at issue would have been classified as expenses and, therefore, not recovered by the Company during the rate freeze. The revised accounting standard, however, is consistent with USOA-Gas, 220 C.M.R. § 51.00 et seq., which provides that both direct employee and contract labor associated with capital projects, such as information technology projects, are capitalized[83] (USOA-Gas § 3, Gas Plant Accounts ¶ 3, Components of Construction Cost). Therefore, the Department finds that the information technology-related labor costs at issue were properly classified by the Company as capital expenditures (see Exh. AG-16-4, at 2). Accordingly, we find that no adjustment to rate base is necessary.

b. Merger-Related Costs and Savings

Consistent with Department precedent, the Merger Settlement allows the Company to recover merger-related costs upon a showing that merger-related savings equal or exceed those

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81 The cost of software that the Company uses internally will be expensed if the expected cost of the project is less than $100,000 (Exh. AG-16-4, Att. (b) at 1).

82 Conversely, if the job is an expensed job, the operations internal labor is classified as an expense (Tr. 7, at 568).

83 The Company's revised accounting policy also is consistent with the accounting guidelines provided in Statement of Position 98–1, Accounting for the Costs of Computer Software Developed or Obtained for Internal Use, and later codified by the FASB in Account Standards Codification 350-40, "Intangibles -- Good Will and Other -- Internal Use Software" (see Exh. AG-16-4, Att. (b) at 1).

costs (Merger Settlement at Art. II (14)). See, e.g., D.P.U. 10-55, at 378; D.T.E. 99-19, at 68; D.T.E. 98-128, at 8-9, 85-86; D.T.E. 98-27, at 8; Boston Edison Company, D.P.U./D.T.E. 97-63, at 7 (1998); Mergers and Acquisitions, D.P.U. 93-167-A at 6, 7, 9 (1994). Once this showing is made, NSTAR Gas shall amortize recovery of its merger-related costs over a ten-year period (Merger Settlement at Art. II (14), (15)).

The Company proposes to recover $4,847,546 in merger-related costs over a ten-year period, or approximately $484,755 annually (Exhs. NSTAR-EHC-1, at 12; NSTAR-MFF-5, WP MFF-22, at 3 (August 21, 2015)). The Company bases its request upon a purported showing that its merger-related savings for the ten-year amortization period will exceed the total of merger-related costs (Company Brief at 20-21; Company Reply Brief at 35-36). As part of this showing, NSTAR Gas contends that a $3.0 million payment received by ratepayers in 2012 as a result of the Merger Settlement represented an immediate credit of future merger-related cost savings and, therefore, it need only demonstrate additional savings of $1.85 million to be eligible to recover $4.85 million in merger-related costs (Company Brief at 20-21; Company Reply Brief at 35-36).

Pursuant to the Merger Settlement, the Company filed a 2013 Merger Report showing its calculation of costs and savings associated with the merger (Exh. NSTAR-EHC-2). The Department finds that the Company's allocated share of merger-related costs is approximately $4.85 million (Exhs. NSTAR-EHC-1, at 12; NSTAR-EHC-2, at 7; NSTAR-EHC-3; NSTAR-MFF-5, WP MFF-22, at 3 (August 21, 2015); Tr. 2, at 124-125). Accordingly, in order to recover these costs, the Company must show merger savings in excess of $4.85 million (Merger Settlement at Article II (14)).

As an initial matter, the Department does not accept the Company's assertion that the $3.0 million credit to ratepayers made pursuant to the Merger Settlement qualifies as merger-related savings for the purpose of determining whether merger-related savings exceed merger-related costs. This credit was a one-time payment to customers for the purpose of providing an immediate tangible benefit from the Merger Settlement, regardless of whether additional economic benefits might be realized through lower costs in subsequent base rate cases. See D.P.U. 10-170-B at 35. Therefore, the credit does not represent actual cost savings directly attributable to efficiencies gained from the merger. See D.P.U. 10-170-B at 35.

Nonetheless, the Department finds that the Company has demonstrated that its merger-related savings exceed it merger-related costs. Pursuant to the 2013 Merger Savings Report, the net savings over the ten-year period following the merger allocated to NSTAR Gas are expected to be $52.3 million (Exhs. NSTAR-EHC-1, at 10; NSTAR-EHC-2, at 7; NSTAR-EHC-3). No party contested the savings calculations contained in the 2013 Merger Savings Report. Further, the evidence shows that the Company's cost of service in this case includes $2.7 million in merger-related savings arising in areas such as corporate insurance, contract services, professional services, and materials and supplies procurement[84] (Exhs. NSTAR-EHC-1, at 11; NSTAR-EHC-2; NSTAR-EHC-3, at 7-44; Tr. 2, at 131, 176). These actual savings alone exceed the approximately $485,000 in costs that the Company seeks to recover annually through rates over the next ten years.

Based on this evidence, the Department finds that NSTAR Gas has demonstrated that its merger-related savings will exceed its merger-related costs. Therefore, pursuant to the Merger

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84 In addition, the cost of service includes $587,000 in employee benefit-related savings related to the merger (Exhs. NSTAR-BPP-1, at 18; DPU-6-13 & Att.).

Settlement, we find that the Company is eligible to recover $4,847,546 in merger-related costs over a ten-year period (see Merger Settlement at Art. II (14)). See also D.P.U. 10-55, at 378; D.T.E. 99-19, at 68; D.T.E. 98-27, at 8; D.T.E. 98-128, at 8-9, 85-86; D.P.U./D.T.E. 97-63, at 7; D.P.U. 93-167-A at 6, 7, 9. Accordingly, the Department accepts the Company's proposed adjustment to cost of service of $484,755.

Finally, the Attorney General, DOER and TEC argue that if the Department finds, as we do above, that the 2013 Merger Report provides a sufficient basis for recovery of merger-related costs, then the Department should adjust the Company's revenue requirement by the annualized savings to account for merger-related savings in the rate year and beyond (Attorney General Brief at 87; Attorney General Reply Brief at 1-11; DOER Brief at 4-5; TEC Reply Brief at 6). As noted above, however, the Company's proposed cost of service includes approximately $2.7 million in savings achieved as a result of the merger. These savings will flow to customers in the rate year and beyond through rates that are lower than they otherwise would have been in the absence of the merger.[85] Accordingly, we conclude that no further adjustment to the Company's cost of service is required.

B. Employee Compensation and Benefits

1. Introduction

When determining the reasonableness of a company's employee compensation expense, the Department reviews the company's overall employee compensation expense to ensure that its

85 As the Company explains, any additional savings expected to be achieved over the next ten years are primarily associated with items such as avoided inflation of operating costs eliminated in prior years and avoided revenue requirement associated with capital additions that were avoided due to labor reductions (Exh. NSTAR-EHC-2, at 20; Tr. 2, at 110, 112, 125). These savings will be accounted for when new rates are established in a subsequent rate case.

compensation decisions result in a minimization of unit-labor costs. D.P.U. 10-55, at 234; D.P.U. 96-50 (Phase I) at 47; Cambridge Electric Light Company, D.P.U. 92-250, at 55 (1993). This approach recognizes that the different components of compensation (i.e., 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. D.P.U. 92-250, at 55. In addition, the Department requires a company to demonstrate that its total unit-labor cost is minimized in a manner supported by its overall business strategies. D.P.U. 92-250, at 55.

A company is required to provide a comparative analysis of its compensation expenses to enable a determination of reasonableness by the Department. D.P.U. 96-50 (Phase I) at 47. The Department evaluates the per-employee compensation levels, both current and proposed, relative to the companies in the utility's service territory and utilities in the region that compete for similarly skilled employees. D.P.U. 96-50 (Phase I) at 47; D.P.U. 92-250, at 56; Bay State Gas Company, D.P.U. 92-111, at 103 (1992); D.P.U. 92-78, at 25-26.

The Company states that it uses a "total rewards" compensation philosophy that is designed to compensate employees competitively in comparison to the energy/utility and general industry sectors (Exh. NSTAR-SL-1, at 4). The major components of NSTAR Gas' employee compensation program are: (1) base pay; (2) incentive compensation; (3) health-related benefits including comprehensive medical, dental, and vision insurance, prescription drug benefits, a health flexible spending account, and wellness programs; (4) life and accident insurances; (5) illness and disability insurances; (6) a defined contribution plan; (7) a 401(k) savings plan;

(8) a defined pension benefit plan for certain employees;[86] and (9) vacation, holiday, and sick pay (Exhs. NSTAR-MFF-1, at 25-26; NSTAR-BBP-1, at 3-4; DPU-6-9; AG-1-42, Att. (a) at 24-27; AG-1-42, Att. (b) at 16, 20-21, 43-44; AG-1-50).

2. Service Companies

During the test year, NSTAR Gas incurred union and non-union payroll costs related to services rendered by two service companies, NUSCO and NSTAR Electric and Gas Company ("NE&G") (Exhs. NSTAR-MFF-1, at 8; NSTAR-MFF-2, Sch. MFF-13 (August 21, 2015); DPU-14-8, Atts. (a), (b)).[87]

The Department permits rate recovery of payments to affiliates where these payments are: (1) for services that specifically benefit the regulated utility and 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 method that is both cost-effective in application and nondiscriminatory for those services specifically rendered to the utility by the affiliate and for general services that may be allocated by the affiliate to all operating affiliates. D.P.U. 12-25, at 231; D.P.U. 89-114/90-331/91-80 (Phase One) at 79-80; Hingham Water Company, D.P.U. 88-170, at 21-22 (1989); AT&T Communications of New England, Inc., D.P.U. 85-137, at 51-52 (1987).

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86 The defined pension benefit plan was closed to new union and non-union entrants on April 1, 2013, and October 1, 2012, respectively (Exhs. NSTAR-BBP-1, at 4; AG-1-50, Att. (b) at 1).

87 Beginning on April 10, 2012 (i.e., the effective date of the merger of Northeast Utilities and NSTAR), NUSCO and NE&G operated as a single service company despite being separate legal entities (Exh. NSTAR-MFF-1, at 8-9; Tr. 1, at 39-42). Effective January 1, 2014, NE&G was legally merged into NUSCO, with NUSCO as the surviving entity (Exh. NSTAR-MFF-1, at 8-9). On February 2, 2015, NUSCO registered the trade name "Eversource Energy Service Company" with the Commonwealth (Exh. DPU-5-2 & Att. at 1). Throughout this Order, we refer to the service company by its legal names in effect during the 2013 test year (i.e., NUSCO and NE&G).

NUSCO and NE&G provide administrative, corporate, legal, and management services to NSTAR Gas and other operating subsidiaries of Northeast Utilities (Exhs. NSTAR-MFF-1, at 9; AG-1-26, Att. (c), Att. (e) at exh. A; AG-1-28 & Att. (b)). These services are provided pursuant to executed service agreements that designate the type of services to be performed and the method of calculating the charges for these services (Exhs. NSTAR-MFF-1, at 9; AG-1-26, Atts. (c)-(f); AG-1-26, Att. (Supp.)). The services NUSCO and NE&G provide to NSTAR Gas are necessary to the Company's business and, thus, specifically benefit NSTAR Gas (Exhs. NSTAR-MFF-1, at 9; DPU-14-9; AG-1-26, Atts. (c)-(f); AG-1-26, Att. (Supp.); AG-1-28 & Att. (b)). Moreover, these services do not duplicate any services provided by the Company's personnel (Exhs. NSTAR-MFF-1, at 9; DPU-14-9; AG-1-26, Atts. (c)-(f); AG-1-28 & Att. (b)).

With respect to the allocation methods, the service company charges from NUSCO and NE&G are either (1) direct charges, which are costs incurred and work performed by service company personnel that are directly related to NSTAR Gas, or (2) common costs, which are allocated among the respective subsidiaries receiving the service based on allocation factors and billing pools (Exh. NSTAR-MFF-1, at 9). The Department finds that the costs are allocated to NSTAR Gas by a formula that is both cost-effective and nondiscriminatory (Exhs. NSTAR-MFF-1, at 9; NSTAR-SL-1, at 4-5; NSTAR-SL-6; DPU-14-9 & Att.; AG-1-28, Atts. (c) at 5, 7-9, (d) at 5, 8-11, (e) at 5). Accordingly, subject to our findings below, the Department will include the payroll costs associated with the services provided by NUSCO and NE&G in NSTAR Gas' cost of service.

3. Union Wage Increases

a. Introduction

NSTAR Gas has a separate collective-bargaining agreement or memorandum of understanding with two unions: (1) Local 369 of the Utility Workers Union of America, AFL-CIO ("Local 369"); and (2) Local 12004, United Steelworkers of America, AFL-CIO ("Local 12004") (Exhs. NSTAR-SL-1, at 7; DPU-7-1, Att.; AG 1-42, Att. (a) (Supp.)). During the test year, NSTAR Gas booked $23,490,226 in payroll expenses for union personnel, including base wages and overtime pay (Exhs. NSTAR-MFF-2, Sch. MFF-13, at 2 (August 21, 2015); NSTAR-MFF-5, WP MFF-13 (August 21, 2015); DPU-14-8, Atts. (a), (b); (d)).[88] The Company proposes to increase its test year union payroll expenses by $2,179,424 (Exhs. NSTAR-MFF-1, at 34; NSTAR-MFF-2, Sch. MFF-13, at 2 (August 21, 2015); DPU-14-8, Atts. (a), (b), (d)).

The increase of $2,179,424 is comprised of: (1) $97,490 based on the annualization of a 2.75 percent wage increase for Local 369 that took effect June 2, 2013; (2) $213,868 based on a 2.50 percent wage increase for Local 369 that took effect June 2, 2014; (3) $263,058 based on a three percent wage increase for Local 369 that took effect June 2, 2015; (4) $248,371 based on a 2.75 percent wage increase for Local 369 scheduled to take effect June 2, 2016; (5) $112,438 based on the annualization of a three percent wage increase for Local 12004 that took effect April 1, 2013; (6) $416,499 based on a 2.75 percent wage increase for Local 12004 that took

88 The $23,490,226 in payroll costs for union personnel consists of: (1) $17,183,430 in direct costs ($4,036,093 for Local 369 employees and $13,147,337 for Local 12004 employees); (2) $4,863,383 in costs allocated from NUSCO and NE&G ($4,107,204 for Local 369 employees and $756,179 for Local 12004 employees); and $1,442,413 in HHPP-related costs ($313,948 for Local 369 employees and $1,129,465 for Local 12004 employees (Exh. DPU-14-8, Atts. (a), (b), (d)).

effect April 1, 2014; (7) $427,953 based on a 2.75 percent wage increase for Local 12004 that took effect April 1, 2015; and (8) $399,747 based on a 2.50 percent wage increase for Local 12004 scheduled to take effect April 1, 2016 (Exhs. NSTAR-MFF-1, at 34; NSTAR-MFF-2, Sch. MFF-13, at 1 (August 21, 2015); DPU-7-1, Att.; AG 1-42, Att. (a) (Supp.)).

b. Positions of the Parties

NSTAR Gas argues that it has demonstrated that its union compensation costs are reasonable and, thus, the Department should approve the recovery of such costs (Company Brief at 95). Specifically, the Company asserts that the union wage rates are set through the collective bargaining process and that the proposed increases are known and measurable (Company Brief at 95, citing Exhs. NSTAR-SL-1, at 10; AG-1-42; Tr. 6, at 486). The Company also maintains that, consistent with Department precedent, the proposed increases take effect before the midpoint of the first twelve months after the anticipated rate increase takes effect (Company Brief at 94-95, citing Exhs. NSTAR-SL-1, at 10; AG-1-42; Tr. 6, at 486). In addition, NSTAR Gas contends that the Company performed an analysis of hourly union wages compared to those of other Northeast region employees that demonstrates the wage levels are reasonable (Company Brief at 95-96, citing Exh. NSTAR-SL-2). No other party commented on the Company's proposal.

c. 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 date of 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 proposed increase must be reasonable. D.P.U. 96-50 (Phase I) at 43; D.P.U. 95-40, at 20; D.P.U. 92-250, at 35; Western Massachusetts Electric Company, D.P.U. 86-280-A at 74 (1987).

NSTAR Gas has a collective bargaining agreement and a memorandum of agreement[89] covering its union employees (Exhs. NSTAR-SL-1, at 10-11; DPU-7-1; AG-1-42, Att. (a); AG-1-42, Att. (a) (Supp.)). Pursuant to these agreements, the proposed increases take effect prior to July 1, 2016 (i.e., before the midpoint of the first twelve months after the rate increase allowed herein takes effect on January 1, 2016) (Exhs. NSTAR-SL-1, at 9; AG-1-42, Att. A (Supp.); DPU-7-1, Att.). In addition, because the proposed increases are based on signed collective bargaining agreements, the increases are known and measurable (Exhs. DPU-7-1; AG-1-42, Att. (b); AG-1-42 (Supp.), Att. (a)). Finally, the Company submitted a comparison of its union salaries to those of other utilities in the Northeast (Exhs. NSTAR-SL-1, at 8; NSTAR-SL-2; AG-10-18). The comparison demonstrates that NSTAR Gas' union hourly wages including the scheduled increases are reasonable in relation to other utilities in the Northeast (Exhs. NSTAR-SL-1, at 8; NSTAR-SL-2; DPU-7-2; AG-10-18).

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 Company's proposed adjustment to union wages is allowed. Accordingly, we allow NSTAR Gas' proposed increase of $2,179,424 to its test year cost of service.

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89 The memorandum of agreement was signed by the Company and Local 369 on June 1, 2015, and ratified by Local 369 members on June 8, 2015 (Exh. AG 1-42 & Att. (a) (Supp.)).

4. Non-Union Wage Increases

a. Introduction

During the test year, NSTAR Gas booked $10,123,934 in payroll expenses, including base wages and overtime pay, for non-union personnel (Exhs. NSTAR-MFF-2, Sch. MFF-13, at 2 (August 21, 2015); NSTAR-SL-1, at 12; DPU-14-8, Atts. (a), (b)).[90] The Company proposes to increase its test year non-union payroll expenses by $860,813 based on increases in non-union payroll that NSTAR Gas asserts will occur prior to the midpoint of the rate year (i.e., prior to July 1, 2016) (Exhs. NSTAR-MFF-1, at 34; NSTAR-MFF-2, Sch. 13, at 2 (August 21, 2015); NSTAR-SL-1, at 13-14). The proposed increase to the test year cost of service of $860,813 is comprised of: (1) $61,580 based on the annualization of non-union payroll adjustments made in 2013; (2) $248,845 based on a three percent increase that took effect on April 4, 2014; (3) $256,310 based on a three percent increase that took effect on April 1, 2015; (4) $220,000 based on a 2.5 percent increase scheduled to take effect on April 1, 2016; (5) $14,141 based on the annualization of non-union NUSCO payroll adjustments made in 2013; (6) $57,145 based on a three percent NUSCO increase that took effect on April 4, 2014; (7) $58,859 based on a three percent NUSCO payroll increase that took effect on April 1, 2015; and (8) $50,521 based on a 2.5 percent NUSCO payroll increase scheduled to take effect on April 1, 2016; and (9) a credit of $106,588 to reflect annualized 2013 merger reductions (Exhs. NSTAR-MFF-2, Sch. MFF-13, at 2 (August 21, 2015); DPU-6-4).

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90 The $10,123,934 in payroll costs for non-union personnel consists of (1) $4,279,089 in direct costs, and (2) $5,844,845 in costs allocated from NUSCO and NE&G (Exhs. NSTAR-MFF-2, Sch. 13, at 2 (August 21, 2015); DPU-6-4; DPU-14-8, Atts. (a), (b)).

b. Positions of the Parties

The Company argues that it has demonstrated the reasonableness of its compensation costs for non-union employees and, therefore, such costs should be approved by the Department (Company Brief at 96). The Company contends that it compared the base pay of non-union employees to the base pay for employees in similar positions at comparable employers, and that its comparison demonstrates that the proposed adjustments are closely aligned with the relevant markets (Company Brief at 96, citing Exh. NSTAR-SL-1, at 14-16; Tr. 6, at 491-493). NSTAR Gas claims that it established a salary range for each position that is set at 90 percent to 110 percent of the median market rate (Company Brief at 96, citing Exh. NSTAR-SL-1, at 11).

The Company asserts that it has historically granted an increase for non-union employees on an annual basis since 2006 (Company Brief at 96, citing Exh. NSTAR-SL-1, at 13). Further, the Company contends that it committed to a three percent increase for non-union employees for 2015 (Company Brief at 96, citing Exh. DPU-6-7). In addition, NSTAR Gas maintains that the proposed increases are in line with industry trends and the general prevalence of merit increases in the energy/utility and general industry sectors (Company Brief at 96-97, citing Exhs. NSTAR-SL-1, at 19; NSTAR-SL-7; Tr. 6, at 494-495).

Finally, the Company claims that it calculated payroll taxes consistent with the Department’s standards (Company Brief at 114). Thus, NSTAR Gas asserts that the Department should approve the payroll taxes (Company Brief at 114). No other party commented on the Company’s proposed increase for non-union employees or its payroll tax calculation.

c. Analysis and Findings

To recognize an adjustment for increases in non-union wages that take place prior to the issuance of an Order, a company must demonstrate that such increases are known and measurable and also reasonable. See D.P.U. 08-35, at 81-82, 87; D.P.U. 92-250, at 35; Fitchburg Gas and Electric Light Company, D.P.U. 1270/1414, at 14 (1983). To recognize an adjustment for an increase in non-union wages that occurs post-Order, a company must demonstrate that: (1) there is an express commitment by management to grant the increase; (2) there is a 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; D.P.U. 1270/1414, at 14. In addition, only non-union salary increases that are scheduled to take effect before the midpoint of the first twelve months after the rate increase may be included in rates. D.P.U. 85-266-A/85-271-A at 107.[91]

Regarding the 2013, 2014, and 2015 non-union payroll increases, NSTAR Gas provided evidence that the increases took place (Exhs. NSTAR-MFF-1, at 31, 33; NSTAR-MFF-2, Sch. MFF-13, at 2 (August 21, 2015); NSTAR-SL-1, at 13; AG-1-41, Att.; AG-6-15). For the 2016 increase, the Company provided a management commitment letter stating that a 2.5 percent payroll increase for non-union NSTAR Gas and NUSCO employees would take place on

91 While the Department has been consistent in its application of the standard of review for non-union payroll increases, the Department has not stated this standard of review in a consistent manner in its prior rate Orders. See D.T.E. 03-40, at 111 (increase must take effect within six months after issuance of the rate Order); D.P.U. 86-280-A at 73-74 (increase must take effect prior to the midpoint of the twelve months following the date of the Order); Boston Gas Company, D.P.U. 1100 (1982) (increase must take effect within a reasonable period after the issuance of the Order). Here, the Department affirms that any proposed non-union wage increase must take effect prior to the midpoint of the twelve months following the effective date of the rate increase.

March 27, 2016 (Exh. DPU-6-7, Att. (Supp.)). Thus, the Department finds that the non-union payroll increases of $860,813 are known and measurable.

With respect to the non-union payroll costs, NSTAR Gas demonstrated an historical correlation between union and non-union raises (Exhs. NSTAR-SL-4; AG-1-41, Att.; AG-6-14, at 2-3). Specifically, between 2006 and 2014, annual union wage increases were between 2.5 percent and 3.25 percent, and non-union increases were between 2.75 percent and 4.8 percent (Exhs. NSTAR-SL-4; AG-1-41, Att.; AG-6-14, at 2-3). Therefore, the Department finds that a sufficient correlation exists between union and non-union wage increases. See Fitchburg Gas and Electric Light Company, D.P.U. 07-71, at 76 (2008); Essex County Gas Company, D.P.U. 87-59-A at 18 (1988).

Finally, with respect to the reasonableness of the non-union wage increases, the Company compensates employees at the median of the marketplace for base pay and total cash compensation (Exhs. NSTAR-SL-1, at 15; NSTAR-SL-5; NSTAR-SL-6; NSTAR-SL-7). NSTAR Gas annually reviews its salary adjustments and total compensation against external market trends for energy/utility companies, and relied on salary surveys to demonstrate that non-union wage increases are in line with those of the utility industry overall (Exhs. NSTAR-SL-1, at 15-23; NSTAR-SL-5; NSTAR-SL-6; NSTAR-SL-7; AG-10-1, Att.; AG-10-3, Att.). The Department finds that the market compensation data presented by NSTAR Gas are sufficient to confirm the reasonableness of the Company's non-union salary levels. See D.P.U. 10-55, at 245; D.T.E. 05-27, at 109; D.T.E. 02-24/25, at 94.

Based on the above, the Department finds that NSTAR Gas has demonstrated that (1) management has expressly committed to granting the wage increases, (2) there is a historical correlation between union and non-union payroll increases, (3) the increases are reasonable, and (4) the increases will take effect prior to the midpoint of the twelve months following the rate increase. Accordingly, we allow NSTAR Gas' proposed adjustment for non-union wages.

5. Incentive Compensation

a. Introduction

The Company offers one incentive compensation program, the Northeast Utilities Corporate Incentive Plan ("Incentive Plan") (Exhs. NSTAR-SL-1, at 23; DPU-6-8). All non-union NSTAR Gas employees are eligible to participate in the Incentive Plan subject to conditions contained in the Incentive Plan (Exhs. NSTAR-MFF-1, at 34; DPU-6-8, Att. A at 3-4; DPU-14-3).

The Company has an earnings per share goal that serves as a trigger for funding the Incentive Plan (Exhs. NSTAR-SL-1, at 23-24; DPU-14-1; AG-6-19 & Att.; AG-10-5; DPU-6-8 & Att. (a)). Once a determination is made to fund the Incentive Plan, any incentive payments to individual employees are determined by the individual's performance goals, which are specifically related to the job the employee is performing in the service of customers (Exhs. NSTAR-SL-1, at 23-24; DPU-14-1; AG-6-18; AG-10-5; DPU-6-8 & Att. (a)). The Incentive Plan includes four categories of performance goals, which are tied to an employee's specific job: (1) an employee category, which includes two goals related to employee health and safety; (2) a customer category, which includes two goals related to customer satisfaction and employee and Company performance; (3) an operational excellence category, which includes seven goals focused on operation performance and maintenance of the gas distribution system; and (4) a financial category, which includes four goals relating to cost containment and efficiencies (Exhs. NSTAR-SL-1, at 25; DPU-14-1; DPU-14-2, Att.; AG-6-18; AG-10-5; DPU-6-8 & Atts. (a), (b)).

During the test year, NSTAR Gas booked $3,144,373 in incentive compensation expense (Exhs. NSTAR-MFF-1, at 35; NSTAR-MFF-2, Sch. MFF-14 (August 21, 2015)).[92] The Company states that, during the test year, it paid out incentive compensation at greater than its target level of $2,073,498 (Exhs. NSTAR-MFF-1, at 35; AG-6-20). Therefore, to arrive at its incentive compensation expense adjustment, the Company first decreased its test year expense by $1,070,875 to represent the target level variable compensation for the existing 2014 accrual based on the 2014 head count (Exh. NSTAR-MFF-2, Sch. MFF-14 (August 21, 2015); see also Exhs. NSTAR-MFF-1, at 35; AG-6-20). NSTAR Gas then escalated the target level variable compensation of $2,073,498 to the midpoint of the rate year to reflect salary increases by multiplying the 2014 actual amount by 5.331 percent and adding the resulting $114,577 to the 2014 actual target amount (Exhs. NSTAR-MFF-1, at 35; NSTAR-MFF-2, Sch. MFF-14 (August 21, 2015)). This results in a total net decrease of $956,298 to the test year costs and a test year adjusted pro forma incentive compensation proposed by the Company of $2,188,075 (Exh. NSTAR-MFF-2, Sch. MFF-14 (August 21, 2015)).

b. Positions of the Parties

The Company argues that its Incentive Plan is consistent with the Department's requirements because it is based on the individual performance of the employee and the performance of the business unit in which that employee works (Company Brief at 97,

92 The $3,144,373 in incentive compensation is comprised of: (1) $1,806,308 in direct NSTAR Gas costs, and (2) $1,338,065 in costs allocated from NUSCO (Exh. NSTAR-MFF-2, Sch. MFF-14 (August 21, 2015)).

citing Exh. NSTAR-SL-1, at 23; Tr. 6, at 520). NSTAR Gas maintains that it ensures that its employees are committed to meeting customer needs by establishing performance goals that are based on providing safe, reliable, and reasonable cost services to customers (Company Brief at 97-98, citing Exh. NSTAR-SL-1, at 24-25). The Company claims that incentive compensation is a necessary mechanism that allows the Company to remain competitive in the labor market (Company Brief at 98, citing Exhs. NSTAR-SL-1, at 26; AG-1-42). The Company asserts that these factors demonstrate that its Incentive Plan is reasonable (Company Brief at 98).

NSTAR Gas notes that during the test year, it paid out more incentive compensation than its target level (Company Brief at 98, citing Exhs. NSTAR-MFF-1, at 35; NSTAR-MFF-2, Sch. MFF-14, at 1 (June 15, 2015)). The Company maintains that its proposed adjustment more accurately reflects the target compensation, and asserts that the Department should approve the adjustment (Company Brief at 98, citing Exhs. NSTAR-MFF-1, at 35; NSTAR-MFF-2, Sch. MFF-14, at 1 (June 15, 2015)). No other party commented on the Company's proposed incentive compensation adjustment.

c. Analysis and Findings

The Department has traditionally allowed incentive compensation expenses to be included in a utility's cost of service if (1) the expenses are reasonable in amount, and (2) the incentive plans are reasonably designed to encourage good employee performance. D.P.U. 07-71, at 82-83; D.P.U. 89-194/195, at 34. 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.

The Department must first determine whether the Incentive Plan is reasonable in design. A portion of the Company's Incentive Plan is tied to meeting financial performance objectives (Exhs. NSTAR-SL-1, at 23-24; AG-10-5 & Att.; DPU-6-8). The Department has articulated its expectations on the use of financial targets in incentive plans and the burden required to justify the recovery of such costs in rates. D.P.U. 10 55, at 253-254. Specifically, where companies seek to include financial goals as a component of incentive compensation design, the Department expects to see the attainment of such goals used as a threshold component with job performance standards designed to encourage good employee performance (e.g., safety, reliability, and customer satisfaction goals) used as the basis for determining individual incentive compensation. See D.P.U. 10 55, at 253-254. In the present case, the Company appropriately uses financial incentives as the threshold component (i.e., to determine whether the Incentive Plan will be funded) and then uses job performance measures as the basis for determining individual compensation awards (Exhs. NSTAR-SL-1, at 24-25; DPU-14-1; AG-6-19; AG-10-5 & Att.; DPU-6-8 & Att.). These performance measures include objectives related to safety, customer service, and process improvement (Exhs. NSTAR-SL-1, at 24-25; DPU-14-1; AG-10-5 & Att.; DPU-6-8 & Att.). The Department has previously found that these types of performance measures are appropriate as they are directly aligned with the interests of ratepayers. D.P.U. 10-70, at 104. Based on the above considerations, the Department finds that the Incentive Plan is reasonable in design.

The Department must next determine whether the incentive compensation costs are reasonable. The Company has provided documentation regarding base salaries and target level compensation compared to the market (Exhs. NSTAR-SL-1, at 25-28; NSTAR-SL-5;

NSTAR-SL-6). Based on our review of this evidence, the Department finds that NSTAR Gas has demonstrated that its incentive compensation costs are reasonable. See D.P.U. 10-70, at 103; D.P.U. 09-39, at 140.

For the reasons outlined above, the Company's proposed adjustment to incentive compensation is allowed. Accordingly, the Department will include incentive compensation of $2,188,075 in NSTAR Gas' cost of service.

6. Employment Benefits

a. Introduction

As noted in Section VI.B.1 above, the components of NSTAR Gas' benefits include: (1) health-related benefits including comprehensive medical, dental, and vision insurance, prescription drug benefits, a health flexible spending account, and wellness programs; (2) life and accident insurances; (3) illness and disability insurances; (4) a 401(k) savings plan; and (5) a defined pension benefit plan (Exhs. NSTAR-MFF-1, at 25-27; NSTAR-BBP-1, at 3-4; AG-1-42, Att. (a) at 35-36; AG-1-42, Att. (b) at 22-23; AG-1-50, Att. (b)). NSTAR Gas reported adjusted test year costs for employee benefits of $5,157,558 (Exhs. NSTAR-MFF-2, Sch. MFF-11, at 2 (August 21, 2015); DPU-6-3 & Att. (a)).[93] The Company proposes to increase certain employee benefits costs by $1,553,430, comprising (1) an increase of $845,080 for medical insurance costs based on 2015 working rates, (2) an increase of $78,261 for dental insurance costs based on 2015 working rates, (3) an increase of $520 for vision insurance costs based on 2015 working rates, (4) an increase of $159,688 for the 401(k) savings plan to reflect payroll increases, and (5) an

93 In addition to a capitalization adjustment, the Company removed employee benefits related to the HOPCO facilities as well as costs included in the gas acquisition adjustment (Exhs. NSTAR-MFF-2, Sch. MFF-11, at 2 (August 21, 2015); DPU-6-3, at 2-3).

increase of $469,881 for disability insurance to reflect actual claims and insurance premiums paid in the test year (Exhs. NSTAR-MFF-1, at 26-27; NSTAR-MFF-2, Sch. MFF-11, at 2 (August 21, 2015); DPU-6-3 & Atts. (a)-(f)).

b. Positions of the Parties

The Company argues that it appropriately adjusted the test year level of medical, dental, and vision insurance costs to reflect increases that are expected through July 2016 (Company Brief at 92, citing Exhs. NSTAR-MFF-1, at 25; NSTAR-BPP-1, at 16-18). NSTAR Gas contends that these increases are significantly offset by merger-related savings regarding employee benefits (Company Brief at 92, citing Exhs. NSTAR-MFF-1, at 25; NSTAR-BPP-1, at 16-18). Further, the Company claims that it appropriately applied working rates to represent the per-day employee-expected claims levels for 2015 (Company Brief at 92, citing Exh. NSTAR-MFF-1, at 25). NSTAR Gas asserts that such estimation accounts for fluctuations in staffing levels and, therefore, is reasonable (Company Brief at 92).

In addition, NSTAR Gas argues that the proposed increase to its 401(k) savings plan is appropriate (Company Brief at 92, citing Exh. NSTAR-MFF-1, at 26-27). The Company asserts that it has contained its retirement benefit costs by closing entry to its more volatile defined benefit pension plan and opting for an enhanced defined contribution approach for all new union employees following the 2012 merger (Company Brief at 92, citing Exh. NSTAR-BBP-1, at 14-15; Tr. 6, at 514-515).

Finally, the Company maintains that its proposal to increase its test year disability insurance costs is appropriate as it is based on known and measurable costs (Company Brief at 93). No other party commented on the Company's employee benefits proposals.

c. 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.T.E. 02-24/25, at 161; D.P.U. 92-250, at 106. To be included in rates, medical insurance expenses, such as health, dental, and vision, must be reasonable. D.T.E. 01-56, at 60-61; see D.P.U. 92-78, at 29-30; Nantucket Electric Company, D.P.U. 91-106/91-138, at 53-54 (1991). Further, companies must demonstrate that they have acted to contain their health care costs in a reasonable, effective manner. D.T.E. 01-56, at 60-61; D.P.U. 96-50 (Phase I) at 46; D.P.U. 92-78, at 29; D.P.U. 91-106/91-138, at 53. Finally, any post-test year adjustments to health care expense must be known and measurable. D.T.E. 01-56, at 60-61; D.P.U. 96-50 (Phase I) at 46; North Attleboro Gas Company, D.P.U. 86-86, at 8 (1986).

The Department finds that NSTAR Gas' adjusted test year medical, dental, and vision benefit expenses are reasonable and that the Company has taken reasonable and effective measures to contain its health care costs (see, e.g., Exhs. NSTAR-MFF-1, at 26; NSTAR-MFF-2, Sch. MFF-11, at 2 (August 21, 2015); NSTAR-BBP-1, at 8-12; AG-1-51, Atts. A, B; AG-1-52; AG-11-12; DPU-6-10). Specifically, with the merger of Northeast Utilities and NSTAR Gas, the Company created a standard platform of active health and welfare designs, leveraged the scale of the merged company to market key health and welfare plans, and consolidated vendors for medical, prescription drug, dental, vision, life insurance, and employee assistant programs (Exhs. NSTAR-BPP-1, at 8; AG-1-52; AG-11-19, Att. C; AG-11-20; DPU-6-10). Because of the health plan provider's extensive network, most employee claims are incurred on an in-network basis, which is more cost effective for employees and the Company

(Exh. NSTAR-BBP-1, at 6). In addition, NSTAR Gas periodically benchmarks its benefits programs against the benefits programs of other employers in the energy industry (Exhs. NSTAR-BBP-1, at 5; AG-11-1; AG-11-3, Att.; AG-11-4; AG-11-5; AG-11-8; AG-11-9; AG-11-10; AG-11-11; AG-11-19, Atts. (a) at 26-34, (b) at 18-23). The Company also regularly compares the coverage and cost of its health plan programs to market alternatives to ensure value for cost is maintained (Exhs. NSTAR-BBP-1, at 5-6, 9; AG-1-52). In addition, the Company has introduced a high deductible health plan (Exh. NSTAR-BPP-1, at 7, 8; see Exh. AG-1-52).

Turning to the proposed post-test year increases to medical, dental, and vision insurance costs, the Company relied on working rates provided to NSTAR Gas by its external benefits consultants, which represent the per-employee expected claims levels for 2015 (Exhs. NSTAR-MFF-1, at 26; Tr. 5, at 407-410). In D.P.U. 13-90, at 94, the Department determined that it was inappropriate to use working rates in pro forma adjustments because working rates are set on a broad-based pool of insured parties. Consequently, there is no evidence that the Company's proposed costs are representative of the level of costs expected to be incurred in the future (see Exhs. AG-1-50, Att. A at 1, 2; AG-6-9, Att.; AG-21-6, Att.).[94] Therefore, the Department declines to adopt the Company's 2015 working rates to derive its medical, dental, and vision insurance expense. Instead, we find it appropriate to rely on the adjusted test year amounts as known and measurable. Thus, NSTAR Gas' proposed increases to

94 The Department notes that in D.P.U. 13-75 and D.P.U. 12-25, it appears that the Company updated its test year medical and dental insurance based on working rates. However, neither Order discusses the reasons for this treatment or contains a justification for the departure from the Department's otherwise log-standing precedent. We find that there was no express intention on the Department's part to change its long-standing precedent on healthcare expense and, therefore, neither case is dispositive of our treatment of the matter here.

medical, dental, and vision insurance costs of $845,080, $78,261, and $520, respectively, are disallowed.

The Company proposes to increase its adjusted test year amount of $1,743,130 for its 401(k) savings plan by $159,668, which represents a proposed 9.161 percent salary increase for union and non-union employees (Exhs. NSTAR-MFF-2, Sch. MFF-11, at 2 (August 21, 2015); DPU-6-3).[95] The Department has found that employee contributions to utility-sponsored savings plans are voluntary and, thus, subject to fluctuation. D.P.U. 13-90, at 102-104; D.P.U. 89-114/90-331/91-80 (Phase One) at 66-67; Commonwealth Electric Company, D.P.U. 88-135/151, at 68 (1989). In the absence of a demonstration that the post-test year participation levels are more representative of future participation than the total employee contributions made during the test year, the Department declines to permit any adjustment above the expense booked during the test year. D.P.U. 92-250, at 48; D.P.U. 89-114/90-331/91-80 (Phase One) at 66-67; D.P.U. 88-135/151, at 68.

Here, NSTAR Gas states that its proposed increase is based on the assumption that the increase in savings plan contributions will be consistent with the overall increase in salaries (Exh. NSTAR-MFF-1, at 26-27). Thus, the Company's proposed increase is based on a 9.161 percent increase to union and non-union salaries regardless of whether an employee participates in or makes contributions to the 401(k) savings plan (Exhs. NSTAR-MFF-2, Sch. MFF-11, at 2 (August 21, 2015); DPU-6-3). In addition, the Company has not

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95 In its initial filing, the Company proposed an increase of 9.161 percent based on union and non-union salary increases (Exh. NSTAR-MFF-2, Schs. MFF-11, at 2; MFF-13, at 2). NSTAR Gas subsequently updated its union and non-union salary increases to 9.362 percent to reflect a memorandum of agreement with Local 369, but did not update its proposed increase to the 401(k) savings plan (see Exh. NSTAR-MFF-2, Schs. MFF-11, at 2 (August 21, 2015); MFF-13, at 2 (August 21, 2015)).

demonstrated that the post-test year participation levels are more representative of future participation that those contributions made during the test year. Thus, the Department disallows the Company's proposed increase to its 401(k) savings plan costs of $159,668.

The Company's proposed increase of $469,881 to its disability insurance is based on actual claims and premiums paid during the test year (Exhs. NSTAR-MFF-1, at 26-27; NSTAR-MFF-2, Sch. MFF-11, at 2 (August 21, 2015); AG-1-51, Att. (a); AG-18-12, Att. (a); DPU-6-3, at 1-2). Therefore, we find that the proposed adjustment is known and measurable. In addition, the proposed adjustment is reasonable (Exhs. AG-1-51, Atts. (a), (b); AG-18-12, Att. (a)).

Because a portion of these employee benefit costs are capitalized, the Department must determine an appropriate capitalization amount (Exh. DPU-6-3, Att. (g)). NSTAR Gas' employee benefits programs apply two capitalization rates: (1) a capitalization rate of 38.95 percent attributed to direct NSTAR Gas costs; and (2) a capitalization rate of 11.64 percent attributed to costs allocated from NUSCO (Exh. DPU-6-3, Att. (g)). To determine the Company's capitalized medical, dental, and vision insurance costs, the Department will apply a composite capitalization rate of 32.29 percent based on the weighted average of 38.95 percent and 11.64 percent (Exh. DPU-6-3, Att. (g)).[96] Multiplying the disallowed increase of $923,861 by the composite rate of 32.29 percent produces a capitalization amount of $298,315.

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96 To derive the composite capitalization rate of 32.29 percent, the Department (1) multiplied the sum of the Company's pro forma direct medical, dental, and vision insurance costs of $6,009,367 by the 38.95 percent capitalization rate, producing a capitalized amount of $2,340,648, (2) multiplied the sum of the Company's pro forma allocated share of NUSCo medical, dental, and vision insurance costs of $1,939,006 by the 11.64 percent capitalization, producing a capitalized amount of $225,700, and (3) divided the sum of the two capitalized amounts of $2,566,349 (i.e., $2,340,648 plus

Because all of the 401(k) savings plans are attributed to NSTAR Gas, the Department will multiply the disallowed 401(k) savings plan increase of $159,688 by the NSTAR Gas capitalization rate of 38.95 percent to arrive at a capitalization amount of $62,198 (Exhs. NSTAR-MFF-2, Sch. MFF-1 (August 21, 2015); DPU-6-3, Att. (g)). The sum of $298,315 related to capitalized medical, dental, and vision insurance expenses and $62,198 related to capitalized 401(k) savings plan expenses produces a total capitalized benefits amount of $360,513.

Based on the foregoing, the total disallowance of $1,083,549 less capitalized benefits of $319,908 is $763,641. The Company had proposed a total O&M pro forma adjustment of $1,767,091 expense for employee benefits.[97] The disallowance of $763,641 related to medical, dental, and vision insurance costs and 401(k) savings plan costs produces a pro forma adjustment to employee benefit costs of $1,003,449. Accordingly, the Department reduces the Company's proposed cost of service by $763,641.

C. Pension and Post-Retirement Benefits other than Pension Expense

1. Introduction

NSTAR Gas' current base distribution rates include $4,818,000 in pension and post-retirement benefits other than pension ("PBOP") expenses. NSTAR Electric Company/NSTAR Gas Company, D.P.U. 10-125-A at 2 n.3 (2014); Commonwealth Electric

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$225,700) by the total test year medical, dental, and vision insurance costs of $7,948,373 (Exhs. NSTAR-MFF-2, Sch. MFF-11, at 2 (August 21, 2015); DPU-6-3, Att. (g)).

[97] The Company's total O&M pro forma adjustment includes the removal of employee benefit costs related to the Acushnet LNG and Hopkington LNG facilities, costs included in the gas acquisition adjustment, and the removal of unrecognized gains and losses related to the pension/PBOP plans (Exhs. NSTAR-MFF-1, at 27-28; NSTAR-MFF-2, Sch. MFF-11, at 2).

Company/Cambridge Electric Light Company/Boston Edison Company/NSTAR Gas Company, D.T.E. 03-47-C at 7 n.2 (2004). The Company proposes to remove the $4,818,000 in embedded pension and PBOP costs incurred in the test year from base distribution rates and recover them, instead, through NSTAR Gas' pension adjustment factor ("PAF") (Exh. NSTAR-MFF-1, at 68-69).

2. Positions of the Parties

On brief, the Attorney General references the Company's proposal in terms of the Department's need to consider its contribution to the overall increase in rates, given that certain pension and PBOP costs that were formerly recovered in base rates will now be recovered through a reconciling mechanism (Attorney General Brief at 72-73). The Attorney General does not, however, argue that the proposed change in ratemaking treatment should be disallowed (see Attorney General Brief at 72-73). No other party commented on the Company's proposal.

3. Analysis and Findings

In D.T.E. 03-47-A at 45-46, the Department approved recovery of NSTAR Gas' pension/PBOP costs through a reconciling mechanism, i.e., the PAF. See also D.T.E. 03-47-B (Phase II) at 2-3, 13-14. The Company, however, retained $4,818,000 in pension/PBOP costs embedded in its base distribution rates until its next fully litigated rate case proceeding (Exh. DPU-6-1). The Department finds that the removal of the pension/PBOP costs from base distribution rates is appropriate at this time. Accordingly, the Company's proposed adjustment is allowed.

D. Uncollectibles Expense

1. Introduction

During the test year, NSTAR Gas booked $5,638,292 in bad debt expense related to its distribution service operations (Exhs. NSTAR-MFF-1, at 23; NSTAR-MFF-2, Schs. MFF-6, MFF-8, at 1 (August 21, 2015)). The Company proposes to decrease its distribution-related bad debt expense by $1,410,919 over the test year level based on the application of a bad debt ratio of 2.2914 percent (Exhs. NSTAR-MFF-1, at 22-23; NSTAR-MFF-2, Sch. MFF-8 (August 21, 2015); NSTAR-MFF-5, WP MFF-8, at 1 (August 21, 2015)).

The Company calculated its distribution-related bad debt ratio by dividing its average net write-offs for 2011 through 2013 of $8,869,955,[98] by its average retail revenues for that same period of $387,098,997 (Exhs. NSTAR-MFF-1, at 22; NSTAR-MFF-2, Sch. MFF-8, at 2 (August 21, 2015); NSTAR-MFF-5, WP MFF-8, at 1 (August 21, 2015)). This calculation results in a bad debt ratio of 2.2914 percent (Exhs. NSTAR-MFF-1, at 22; NSTAR-MFF-2, Sch. MFF-8, at 2 (August 21, 2015); NSTAR-MFF-5, WP MFF-8, at 1 (August 21, 2015)). The Company then multiplied the bad debt ratio of 2.2914 percent by test year normalized distribution service revenues of $214,536,834,[99] to arrive at a bad debt expense of $4,915,897

[98] The Company states that its net write-offs are comprised of the actual customer accounts written off for non-payment plus customer balances forgiven through its arrearage forgiveness program less recoveries related to previously written-off account balances (Exhs. NSTAR-MFF-1, at 22; NSTAR-MFF-5, WP MFF-8, at 2 (August 21, 2015)). The Company states that the resulting net write-off ratio is intended to represent the portion of the Company's billed retail revenues that ultimately it will be unable to collect from its customers (Exh. NSTAR-MFF-1, at 22).

[99] The Company's test year firm sales revenues were adjusted to eliminate CGAC billed revenues (see Exh. NSTAR-MFF-2, Sch. MFF-8, at 2 (August 21, 2015)).

(Exhs. NSTAR-MFF-2, Sch. MFF-8, at 2 (May 20, 2015); NSTAR-MFF-5, WP MFF-8, at 1 (May 20, 2015)). Next, the Company reduced the bad debt expense by $688,524, to account for distribution service-related write-offs associated with the Company's arrearage management program ("AMP")[100] (Exhs. NSTAR-MFF-2, Sch. MFF-8, at 2 (August 21, 2015); NSTAR MFF-5, WP MFF-8, at 3 (August 21, 2015)). The resulting bad debt expense of $4,227,373 represents a decrease of $1,410,919 when compared to the Company's test year level of expense of $5,638,292 (Exhs. NSTAR-MFF-1, at 23; NSTAR-MFF-2, Sch. MFF-8 (August 21, 2015)).

The Company also calculated a bad debt expense associated with the proposed revenue increase. The Company multiplied the bad debt ratio of 2.2914 percent by its proposed revenue increase of $23,195,466, to arrive at a proposed bad debt adjustment of $531,501 (Exh. NSTAR-MFF-2, Sch. MFF-3 (August 21, 2015)).[101]

2. Positions of the Parties

On brief, the Company summarizes the bad debt calculations described above (Company Brief at 89-90). The Company argues that its bad debt calculation is consistent with

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[100] NSTAR Gas refers to its AMP as an arrearage forgiveness program.

[101] In its original filing, NSTAR Gas sought to recover $33,905,651 in additional revenues through base distribution rates (Exhs. NSTAR-MFF-2, Sch. MFF-2; NSTAR MFF-4, Sch. 1). The application of the bad debt ratio to the initial requested revenue increase produces a bad debt adjustment of $776,914 (Exh. NSTAR-MFF-2, Sch. MFF-3). During the course of the proceeding, NSTAR Gas reduced its requested base distribution rate increase to $23,195,466 (Exhs. NSTAR-MFF-2, Sch. MFF-2 (August 21, 2015); NSTAR-MFF-4, Sch. 1 (August 21, 2015)). Thus, the Company reduced the bad debt adjustment associated with the requested revenue increase to $531,501(Exh. NSTAR-MFF-2, Sch. MFF-3 (August 21, 2015)).

Department precedent and, therefore, should be approved by the Department (Company Brief at 90). No other party commented on the Company's proposed adjustments.

3. Analysis and Findings

The Department permits companies to include for ratemaking purposes a representative level of bad debt revenues as an expense in cost of service. D.P.U. 09-39, at 164; D.P.U. 96-50 (Phase I) at 70-71; D.P.U. 89-114/90-331/91-80 (Phase I) at 137-140. The Department has found that the use of the most recent three years of data available is appropriate in the calculation of bad debt expense. D.P.U. 96-50 (Phase I) at 71. A company's bad debt ratio is derived by dividing the three-year distribution-related net write-offs by the distribution-related billed revenues for the same period.[102] This bad debt ratio is then multiplied by test year distribution-related billed revenues, adjusted for any distribution revenue increase or decrease that is approved in the current rate case. See D.P.U. 07-71, at 106-109; D.P.U. 96-50 (Phase I) at 71.

The Department finds that the method used by the Company to calculate its bad debt ratio is inconsistent with Department precedent, as the Company improperly included gas supply-related write-offs in its net write-off calculation (Tr. 2, at 159). Given that the Company is allowed dollar-for-dollar recovery of bad debt expense associated with gas supply, write-offs associated with gas supply must be removed from the distribution-related bad debt calculation. See, e.g., D.P.U. 09-39, at 164-165; D.P.U. 07-71, at 107-109. Moreover, we find that the Company inappropriately included in its net write-off calculation write-offs associated with the

102 While the Company presents its bad debt calculation using the three-year average of write-offs and revenues from 2011 through 2013, the resulting bad debt ratio is the same as if the Company used the sum of the write-offs and revenues for this period.

total arrears forgiven through the AMP (Exh. NSTAR-MFF-2, WP MFF-8, at 2 (August 21, 2015); Tr. 2, at 161-162). As noted above, the Company excludes arrearage forgiveness program-related write-offs in the calculation of its bad debt expense (Exhs. NSTAR-MFF-2, Sch. MFF-8, at 2 (August 21, 2015); NSTAR-MFF-5, WP MFF-8, at 3 (August 21, 2015)). However, the Company includes the write-offs in the calculation of the bad debt ratio (Exh. NSTAR-MFF-5, WP MFF-8, at 2 (August 21, 2015); Tr. 2, at 159). Similar to gas supply costs, the Company's AMP costs are recovered on a dollar-for-dollar basis (see M.D.P.U. No. 407C; Exh. NSTAR-RDC-6, at 13-16 (proposed M.D.P.U. No. 402G § 7.0)). As such, it is inappropriate for the Company to include write-offs associated with these costs in its bad debt ratio.

During evidentiary hearings, the Department directed NSTAR Gas to recalculate its bad debt expense by removing from the calculation gas supply-related net write-offs and write-offs associated with the Company's AMP (Tr. 8, at 792; RR-DPU-17). The recalculation produces a bad debt ratio of 1.9084 percent (RR-DPU-17, Att. (b) at 3). The Department finds that the Company has performed this calculation consistent with Department precedent. D.P.U. 09-39, at 164-165; D.P.U. 07-71, at 106-109. Applying the revised bad debt ratio of 1.9084 percent to test year normalized distribution service revenues of $214,536,834 produces a bad debt expense of $4,094,221 (RR-DPU-17, Att. (b)).

As noted above, during the test year, the Company booked $5,638,292 in distribution-related bad debt expense (Exhs. NSTAR-MFF-1, at 23; NSTAR-MFF-2, Schs. MFF-6, MFF-8, at 1 (August 21, 2015)). The Company proposed to decrease its bad debt expense by $1,410,919 to $4,227,373 (Exhs. NSTAR-MFF-1, at 23; NSTAR-MFF-2, Sch. MFF-8 (August 21, 2015)). Based on our findings above, we conclude that the appropriate bad debt expense should be $4,094,221 (RR-DPU-17, Att. (b)). Accordingly, the Department reduces the Company's proposed cost of service by $133,152.

Finally, applying the recalculated bad debt expense of 1.9084 percent to the Company's revenue increase approved in this case of $15,831,322, results in a bad debt adjustment of $302,125. The Company initially proposed a bad debt adjustment of $776,914 relative to its initial requested revenue increase, and then reduced the adjustment to $531,501 to reflect a revised requested revenue increase (Exhs. NSTAR-MFF-2, Sch. MFF-3; NSTAR-MFF-2, Sch. MFF-3 (August 21, 2015); see also n.101 above). Accordingly, the Department further decreases the Company's proposed cost of service by $229,376.

E. Depreciation Expense

1. Introduction

During the test year, NSTAR Gas booked $27,767,097 in depreciation and amortization expense (Exh. NSTAR-MFF-2, Sch. MFF-21 (August 21, 2015)). The Company proposes to reduce its test year depreciation and amortization expense by $734,628 based on the application of new accrual rates to its pro forma plant in service, resulting in an annual depreciation and amortization expense of $27,032,470 (Exhs. NSTAR-MFF-2, Sch. MFF-21 (August 21, 2015); NSTAR-MFF-5, WP MFF-21 (August 21, 2015)).

2. Company's Depreciation Study

The Company's depreciation study is based on plant data as of December 31, 2013, and employs the remaining life method (Exhs. NSTAR-JJS-1, at 2, 5; NSTAR-JJS-2, at 9-11). Under the remaining life method, the net undepreciated plant investment, less net salvage, is apportioned through equal annual depreciation charges over the remaining estimated life of the property (Exh. NSTAR-JJS-1, at 10). For most of its plant accounts, the Company used the retirement rate method[103] to develop an average service life ("ASL") for each account by plotting life table data that were then fitted to Iowa-type survivor curves[104] to determine the appropriate survivor curve for these accounts[105] (Exh. NSTAR-JJS-1, at 6-7).

The Company used the aforementioned depreciation techniques to develop its proposed accrual rates by first estimating the service life and net salvage characteristics for each plant account or subaccount identified as having similar characteristics (Exh. NSTAR-JJS-2, at 11). The Company analyzed historic trends and information provided by its management and operating personnel, including information developed during field inspections, and current gas industry practices, to form its judgments as to ASLs and net salvage characteristics (Exhs. NSTAR-JJS-1, at 8; NSTAR-JJS-2, at 9). Using these data, the Company then calculated composite remaining lives and annual depreciation accrual rates for each depreciable plant account (Exhs. NSTAR-JJS-1, at 9; NSTAR-JJS-2, at 43). The Company's depreciation study

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103 The retirement rate method is an actuarial method of deriving survivor curves based on the average rates at which property of each age group is retired by the Company over the period of time included in the depreciation study (Exh. NSTAR-JJS-2, at 20).

104 Iowa curves are frequency distribution curves that were initially developed at the Iowa State College Engineering Experiment Station during the 1920s and 1930s; these curves are widely accepted in determining average life frequencies for utility plant. Boston Edison Company/Cambridge Electric Light Company/Commonwealth Electric Company/Canal Electric Company, D.T.E. 06-40, at 66-67 n.44 (2006). Initially, 18 curve types were published in 1935; four additional survivor curves were identified in 1957 (Exh. NSTAR-JJS-2, at 14, 20).

105 The ASL and Iowa curve are customarily reported as a combined figure; for example, a "75-R2.5" curve refers to an ASL of 75 years combined with an R2.5 Iowa curve.

produced a composite accrual depreciation rate of 2.68 percent, which is lower than the current composite depreciation accrual rate of 3.05 percent (Exh. NSTAR-JJS-3, at 2).

For Account 390-Structures and Improvements - Offices, NSTAR Gas divided the account into two categories: (1) major office structures, consisting of its Southborough office and Westborough ("Summit") office; and (2) minor offices, consisting of buildings such as service centers (Exhs. NSTAR-JJS-R1, at 30; AG-2-30, Att.). The Company relied on a life span analysis to determine the survivor curve for its major structures (Exh. NSTAR-JJS-R1, at 30). A life span analysis is based on the premise that all of the assets in a particular group at the same location (e.g., generating stations and office buildings) will at some point in the future be retired concurrently, and that all assets at the retired facilities, regardless of their age, will be retired at that time (Exh. NSTAR-JJS-R1, at 30; Tr. 3, at 225). Under the life span method, a property unit's final retirement date is estimated and an interim survivor curve is used to account for interim additions and retirements during the life of the facility (Exh. AG/JP-1, at 42; Tr. 3; at 221). The Company selected retirement dates of 2034 for its Southborough office and 2067 for its Summit office (Exh. NSTAR-JJS-2, at 135). In the case of minor structures, the Company relied on the retirement rate method to develop an ASL of 45 years (see Exhs. NSTAR-JJS-2, at 49, 136; NSTAR-JJS-R1, at 30).

The Company relied on amortization accounting for general plant accounts[106] (Exhs. NSTAR-JJS-1, at 2; NSTAR-JJS-2, at 5; AG-2-11). Under amortization accounting,

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106 Plant booked to these accounts consists of: (1) office furniture and equipment; (2) stores equipment; (3) tools, shop, and garage equipment; (4) communications equipment; and (5) miscellaneous equipment (Exh. NSTAR-JJS-2, at 44). This plant is made up of numerous units of property that represent only a small percentage of total depreciable

plant that is added in each vintage year is presumed for reporting purposes to remain in service throughout its anticipated life, and then retired at the end of that period (Exhs. NSTAR-JJS-1, at 11; NSTAR-JJS-2, at 44-45). Consequently, plant that is retired before the end of the amortization period nonetheless remains on the Company's books until the end of the amortization period. Plant that remains in service as of the end of the amortization period is retired for plant accounting purposes but is not necessarily removed from actual service (Exhs. NSTAR-JJS-2, at 10-11; AG-3-7).

The Company proposes to replace its current across-the-board 15-year amortization rate with several account-specific amortization rates. First, the Company proposes to apply a 20-year amortization rate to Account 390.1-Leasehold Improvements, Account 390.2-Office Furniture, and Account 393-Stores Equipment (Exh. NSTAR-JJS-2, at 49). Second, the Company proposes to apply a five-year amortization rate to Account 391.2-Computers (Exh. NSTAR-JJS-2, at 49). Third, the Company proposes to apply a 25-year amortization rate to Account 393-Tools, Shop, and Garage Equipment (Exh. NSTAR-JJS-2, at 49). Fourth, the Company proposes to apply a 9.28 percent amortization rate to Account 396-Power Operated Equipment (Exh. NSTAR-JJS-2, at 49). Finally, the Company proposes to maintain its current 15-year amortization rate for Accounts 397-Communications Equipment and 398-Miscellaneous Equipment (Exh. NSTAR-JJS-2, at 49).

In the process of conducting the depreciation study, NSTAR Gas identified a deficiency of $3,111,026 in the amortization reserves associated with Accounts 391.1-Office Furniture and Equipment, 391.2-Computers, 393-Stores Equipment, 394-Tools, Shop, and Garage Equipment,

plant in the aggregate but would require a disproportionately large plant accounting effort (Exh. NSTAR-JJS-2, at 11, 44; Tr. 3, at 289-290).

397-Comunications Equipment, and 398-Miscellaneous Equipment[107] (Exh. NSTAR-JJS-2, at 50). The Company attributed this deficiency in large part to the revised amortization rates (Exh. NSTAR-JJS-R1, at 64). In order to adjust the unrecovered reserve and to create what it considers more stable accrual rates for these accounts, the Company identified for each account the reserve balance that would have existed had the proposed amortization rate been used for all assets in that account, as well as the unrecovered difference (Exh. NSTAR-JJS-R1, at 64).[108] The Company proposes to recover the aggregate difference, a total of $3,111,026, over a five-year period, resulting in an annual amortization of $622,205 (Exhs. NSTAR-JJS-1, at 11, 15; NSTAR-JJS-2, at 50; AG-2-12).

3. <u>Attorney General's Depreciation Analysis</u>

The Attorney General examined NSTAR Gas' depreciation study and proposed several adjustments to the Company's ASLs, salvage factors, and amortization components (Exhs. AG/JP-1; AG/JP-2; AG/JP-1/Rebuttal). Based on her review, the Attorney General proposes different ASLs for: (1) Account 367-Mains; (2) Account 380-Services; (3) Account 390-Structures and Improvements; and (4) Account 391.2-Computers (Exh. AG/JP-1, at 10). The application of the Attorney General's proposed ASLs to these

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[107] The Company's reported under-accruals consist of: (1) $94,971 in Account 391.1; (2) $2,011,742 in Account 391.2; (3) $22,844 in Account 393; (4) $999,842 in Account 397; and (5) $8,296 in Account 398 (Exh. NSTAR-JJS-2, at 50). These under-accruals were partially offset by an over-accrual of $26,669 in Account 394 (Exh. NSTAR-JJS-2, at 50).

[108] For example, of the total reserve associated with Account 391.2-Computers of $3,774,313, the Company assigned $1,209,795 to the reserves to those plant assets still considered to be in service and classified the remaining $2,011,742 as the unrecovered difference (Exh. NSTAR-JJS-R1, at 40).

accounts results in a reduction of $2,065,402 in the Company's proposed depreciation expense[109] (Exh. AG/JP-1, at 10). In addition, the Attorney General asserts that the Company should increase the amortization period for Account 303-Intangible Plant – Software from the current five years to at least eight years, which produces a reduction of $195,759 to the Company's proposed amortization expense (Exh. AG/JP-1, at 69-72).

In addition to her service life recommendations, the Attorney General proposes different salvage factors for Accounts 367, 380, and 390. The application of her proposed salvage factors results in a further reduction of $2,776,124 in the Company's proposed depreciation expense[110] (Exh. AG/JP-1, at 52). Finally, the Attorney General asserts that the Company should not be permitted to apply a separate amortization to recover general plant account under-accruals, which produces a further reduction of $622,205 to the Company's proposed amortization expense (Exh. AG/JP-1, at 72-73). Based on these adjustments, the Attorney General recommends an overall reduction of $5,659,490 to the Company's proposed depreciation and amortization expense (Exh. AG/JP-1, at 10, 52, 72, 73).

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109 Specifically, the Attorney General proposes the use of the following ASLs and Iowa curves: (1) 80-R2.5 curve for Account 367; (2) 58-R1.5 curve for Account 380; (3) 50-S0 curve for Account 390; and (4) 7-SQ curve for Account 391.2 (Exh. AG/JP-1, at 10).

110 Specifically, the Attorney General proposes the use of the following salvage factors: (1) negative 35 percent factor for Account 367; (2) negative 35 percent salvage factor for Account 380; and (3) a positive 50 percent salvage factor for Account (Exh. AG/JP-1, at 52).

4. Positions of the Parties

a. Attorney General

i. Overview

The Attorney General argues that the Company's proposal relies on an overly simplistic analysis of the data that is not informed by a meaningful investigation into the trends of net salvage rates (Attorney General Brief at 32). The Attorney General explains that net salvage is not readily ascertained through quantitative methods such as actuarial analyses but rather represents a more subjective area of depreciation analysis requiring the use of historical trends (Attorney General Brief at 32, citing Exh. AG/JP-1-Rebuttal, at 21). The Attorney General contends that because the Company's historical retirement data are limited, it is necessary to determine to what degree it can be relied upon for forecasting depreciation (Attorney General Brief at 32, citing Exh. AG/JP-1-Rebuttal, at 21). The Attorney General adds that while the Company primarily relies on historical averaging, she provided a more detailed analysis of trends that offers a more accurate forecast of future net salvage factors (Attorney General Brief at 32-33).

ii. Account 303 - Software Investment

The Attorney General contends that NSTAR Gas has considerably understated the useful life of its software (Attorney General Brief at 35). In support of her position, the Attorney General notes that the Company has identified 36 software systems that remain in service providing benefits to customers even though the systems were fully depreciated during the past ten years (Attorney General Brief at 35, citing Exhs. AG/JP-1, at 68; AG-3-6, Att.; AG 3-7; AG-14-18). The Attorney General explains that by underestimating the amortization period, the

Company is able to collect an excessive return, rather than recovering only the actual investment in its software (Attorney General Brief at 35, citing Exh. AG/JP-1, at 67–68).

The Attorney General argues that the sole basis for NSTAR Gas' proposed five-year amortization period is a depreciation study that was submitted as part of the Company's last base rate case, D.T.E. 05-85 (Attorney General Reply Brief at 19). The Attorney General contends that the depreciation study in that proceeding is irrelevant, because the underlying proceeding was ultimately settled and the merits of the depreciation study were never adjudicated (Attorney General Reply Brief at 19). The Attorney General adds that even if the depreciation study had been adjudicated, the Company nonetheless must be able to support its proposed amortization in the instant case (Attorney General Reply Brief at 19-20).

Based on these considerations, the Attorney General recommends that the Department reject the Company's proposed five-year amortization period for Account 303 and instead apply an eight-year amortization period (Attorney General Brief at 34-35). The Attorney General contends that an eight-year amortization period is more indicative of the actual useful lives of the Company's computer software (Attorney General Brief at 35, citing Exh. AG/JP-1, at 67-68). The Attorney General also recommends that the Department direct NSTAR Gas to perform a study of life estimations for the Company's software assets (Attorney General Brief at 35).

iii. Account 367-Mains and Account 380-Services

The Attorney General argues that her selected life curve combinations produce better statistical and visual fits than the Company's combinations for Account 367-Mains and Account 380-Services (Attorney General Brief at 25). In support of her position, she asserts that the Company has conceded that the Attorney General's proposed life curve combinations are a better statistical fit than the Company's own proposed life curve combinations for the historical data of Accounts 367 and 380 (Attorney General Brief at 25, 27, citing Exh. NSTAR-JJS-R1, at 9, 22; Tr. 3, at 196-197). Therefore, the Attorney General concludes that there is no material dispute that her proposed life curves are better statistical fits for the historical data in Accounts 367 and 380 than the Company's proposed survivor curves (Attorney General Brief at 26).

Further, the Attorney General asserts that while the Department has previously found that informed judgment can justify a departure from a result otherwise dictated by statistics, sufficient justification for such a departure is required (Attorney General Brief at 28, citing D.P.U. 92-250, at 64; The Berkshire Gas Company, D.P.U. 905, at 13-15 (1982); Massachusetts Electric Company, D.P.U. 200, at 21 (1980)). In this regard, the Attorney General contends that the Company incorrectly assumes that the accelerated replacement of cast iron and bare steel will result in shorter service lives (Attorney General Brief at 28-29, citing Tr. 3, at 296). The Attorney General concludes that the Company has provided insufficient justification to depart from what she considers to be her statistically superior results, and further claims that any deviation from the statistical results of her analyses for Accounts 367 and 380 is not supported by the evidence (Attorney General Brief at 26). Thus, the Attorney General dismisses the Company's use of "informed judgment" to support its proposed survivor curves as "an invention after-the-fact" used to justify shorter average lives to generate additional revenues[111] (Attorney General Brief at 26-27).

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111 By way of example, the Attorney General contends that the Company's depreciation witness contradicted himself by claiming in his direct testimony that the statistical analyses were unaffected by external information, such as the accelerated replacement of cast iron and bare steel mains under the GSEP, and then later claiming in his rebuttal testimony that such accelerated replacements warranted shorter lives than the statistical

Turning to NSTAR Gas' salvage analysis, the Attorney General argues that the Company's use of rolling averages does not sufficiently explain trends in its net salvage values that are historically volatile for these accounts (Attorney General Brief at 33, citing Exhs. NSTAR-JJS-2, at 100; NSTAR-JJS-2, at 104).[112] The Attorney General contends that the Department has previously rejected net salvage proposals based only on averages that are "not based on any analysis of the underlying data" (Attorney General Brief at 34, citing D.P.U. 10-55, at 373). The Attorney General argues that the Company failed to significantly check for the basis of trends in the data supporting its net salvage values and, therefore, the Company's net salvage proposal should not be adopted by the Department (Attorney General Brief at 34).

The Attorney General attributes the higher level of negative net salvage in recent years to abnormally high retirement rates for cast iron and bare steel mains and services (Attorney General Brief at 33, citing Exhs. AG/JP-1-Rebuttal, at 55-56, 60-61). The Attorney General predicts that these high levels of retirements will not continue in the future because the remaining plant balances of cast iron and bare steel mains and services are nominal, representing only four percent of the mains account and less than 0.5 percent of services (Attorney General Brief at 34, citing Exhs. AG/JP-1-Rebuttal, at 55-56, 60-61). The Attorney General asserts that,

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data indicated (Attorney General Brief at 26-27, citing Exhs. NSTAR-JJS-2, at 35; NSTAR-JJS-R1, at 28; Tr. 3, at 185-186).

112 For example, the Attorney General notes that for Account 367, historical data show a difference of over 100 percentage points in net salvage between 2003 and 2004 (Attorney General Brief at 33, citing Exh. NSTAR-JJS-2, at 100). Similarly, the Attorney General notes that for Account 380, the Company recorded negative 21 percent, negative 134 percent, and negative 109 percent net salvage from 2008 to 2010, respectively (Attorney General Brief at 33, citing Exh. NSTAR-JJS-2, at 104).

in fact, the Company's recent experience with net salvage indicates a trend towards less negative salvage factors (Attorney General Brief at 34, citing Exh. AG/JP-1, at 53-63; Attorney General Reply Brief at 18, citing RR-AG-2-3). Finally, the Attorney General contends that her recommended historical net salvage values are closer to industry averages than the net salvage values the Company proposes (Attorney General Brief at 34, citing Exhs. AG/JP-1-Rebuttal, at 58; AG-2-2 Att.; Attorney General Reply Brief at 19, citing Exhs. AG/JP-1, at 58; AG-2-2, Att.).

Based on these considerations, the Attorney General recommends that the Department direct the Company to recalculate its depreciation expense for Account 367 using the 80-R2.5 survivor curve and to recalculate its depreciation expense for Account 380 using the 58-R1.5 survivor curve (Attorney General Brief at 29). The Attorney General further recommends that the Department use her proposed net salvage factors of negative 35 percent for Account 367 and negative 60 percent for Account 380 (Attorney General Brief at 34; Attorney General Reply Brief at 19).

Finally, the Attorney General argues that the Company has not been accounting for the material composition of its mains and services when tracking plant additions and retirements (Attorney General Brief at 37). The Attorney General argues that because ASLs and salvage factors vary depending upon the type of material used in mains and services, the Department should require the Company to maintain records of material types of all mains and services additions and retirements (Attorney General Brief at 37).

iv. Account 390-Structures and Improvements

The Attorney General argues that the Company failed to support its proposed life estimation for Account 390-Structures and Improvements (Attorney General Brief at 29; Attorney General Reply Brief at 16). The Attorney General claims that the Company's analysis here was confined to conclusory statements about its witness' own observations and discussions about the practices of others in the industry and not based on an analysis of relevant data (Attorney General Brief at 29, citing Tr. 3, at 226; Attorney General Reply Brief at 17). In particular, the Attorney General maintains that the Company failed to provide any documentation regarding any other analyses that may have been conducted (e.g., such as records or notes), statistical analysis, or examples of life use (Attorney General Brief at 30, citing Exh. AG-14-14). The Attorney General contends that the Company's "judgment-" or "experience-" based recommendations provide no basis on which to evaluate NSTAR Gas' proposal and that the Department's acceptance of such recommendations here would create a dangerous precedent by allowing companies to propose, in effect, any service life they want for buildings (Attorney General Brief at 30). By contrast, the Attorney General argues that her proposed ASL for Account 390 is supported by an analysis of the Company's historical data of the asset mix in the account, the location, and description of the facilities, and information provided by NSTAR Gas[113] (Attorney General Brief at 30, citing Exh. AG/JP-1, at 43–45).

113 For example, the Attorney General contends that the only evidence supporting the Company's proposed ASL for one office building is that the Company's Worcester general office is 63 years old and that the Company has no plans to retire this building (Attorney General Brief at 31, citing Exhs. AG-14-14; AG-2-30, Att.; Tr. 3, at 226–27; Attorney General Reply Brief at 16-17). Based on the Company's actual experience with its Worcester office, the Attorney General argues that retirement dates much longer than

Turning to NSTAR Gas' salvage analysis for Account 390, the Attorney General argues that the Company omitted crucial data in its analysis (Attorney General Brief at 34-35). Specifically, the Attorney General maintains that NSTAR Gas excluded from its salvage analysis the sale of an office building that generated a positive salvage (Attorney General Brief at 35). Further, the Attorney General maintains that the Company's witness was unaware and, therefore, did not account for a second sale of a service center that had taken place in 2000 (Attorney General Brief at 35, citing Exh. AG/JP-1, at 44, 64-65; Attorney General Reply Brief at 19, citing Exh. AG/JP-1, at 64). The Attorney General contends that the net salvage from those excluded buildings is highly likely to be representative of the net salvage associated with the two major property assets in Account 390 (Attorney General Brief at 35, citing Exhs. AG/JP-1, at 64–65). The Attorney General maintains that including the two buildings in the calculation of net salvage produces a positive net salvage value of 50 percent for this account (Attorney General Brief at 35, citing Exhs. AG/JP-1, at 63-65; NSTAR-JJS-2, at 112; AG-2-17; AG-14-13).

Based on these considerations, the Attorney General recommends that the Department accept her proposed 50-S0 survivor curve and net salvage value of positive 50 percent for Account 390 (Attorney General Brief at 31, 35-36; Attorney General Reply Brief at 19). The Attorney General also requests that the Department direct the Company to conduct and provide life studies in its next depreciation study (Attorney General Brief at 31, citing Exh. AG/JP-1, at 45).

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60 years for the Southborough facility and 65 years for the Summit facility are warranted (Attorney General Brief at 31, citing Exhs. AG/JP-1, at 44-45; AG-14-14).

v. Account 391.2-Computers

The Attorney General argues that the Company's proposed life estimation for Account 391.2 is unsupported by the evidence (Attorney General Brief at 31-32). In this regard, the Attorney General contends that NSTAR Gas provided no statistical analysis or other support for its proposed life estimation but rather selected service lives used by other utilities and the Company for similar assets under depreciation accounting (Attorney General Brief at 32, citing Exh. NSTAR-JJS-2, at 44).

The Attorney General contrasts the Company's analysis for Account 391.2 with her own analysis, including her investigation of vintages of this category of plant still in service (Attorney General Brief at 32, citing Exh. AG/JP-1 at 47; Attorney General Reply Brief at 18). In particular, the Attorney General argues that her 7-SQ life curve recommendation is supported based on a review of industry data (Attorney General Brief at 32, citing Exh. AG/JP-1 at 47). Therefore, the Attorney General recommends that the Department direct the Company to calculate its depreciation expense for Account 391.2 using the 7-SQ life curve combination (Attorney General Brief at 32; Attorney General Reply Brief at 18).

vi. Amortization Reserve Deficiency Adjustment

The Attorney General urges the Department to deny the Company's proposal to collect $622,205 of unrecovered amortization[114] (Attorney General Brief at 36). The Attorney General claims that Account 391.2 has been fully accrued and, therefore, it is no longer necessary to collect additional amortization expense for this type of plant (Attorney General Brief at 36,

114 On brief, the Attorney General attributes the entire proposed amortization to Account 391.2 (Attorney General Brief at 36).

citing Exh. AG/JP-1-Rebuttal, at 19-20). The Attorney General contends that the Company conceded this point (Attorney General Brief at 36, citing Exh. NSTAR-JJS-2, at 49).

The Attorney General also contends that the Company has failed to substantiate its claim that its proposed 15-year amortization period for Account 391.2 had been established in D.T.E. 05-85 (Attorney General Brief at 36, citing Tr. 3, at 278–279). In support of her position, the Attorney General maintains that NSTAR Gas provided other evidence that it implemented a five-year amortization for Account 391.2 pursuant to D.T.E. 05-85[115] (Attorney General Brief at 36, citing Exh. AG-2-22; Tr. 1, at 38-39).

b. Company

i. Life Estimation

NSTAR Gas disputes the Attorney General's contention that her survivor curves are a better fit both statistically and visually, and that the Company's explanations for departing from the statistical best fit lack credibility and justification (Company Brief at 124, citing Attorney General Brief at 25). The Company contends that the Attorney General's criticisms are unfounded and that her suggested survivor curves are unsound (Company Brief at 124).

The Company claims that Attorney General's analysis relies solely on historical data without using informed judgment in estimating service lives (Company Brief at 124, citing Exh. NSTAR-JJS-R1, at 5, 19; Tr. 3, at 194-195, 299-300). The Company maintains that the Attorney General's life estimation approach consists of plotting historical data on a graph,

[115] The Attorney General argues that the testimony of this internal witness, whose responsibilities include overseeing the Company's revenues, should be credited over that of an outside witness who contradicted himself in his own depreciation study (Attorney General Brief at 36-37).

rather than an analytical approach that includes forecasting based on historical data of the property currently in service (Company Brief at 124-125, citing Exh. NSTAR-JJS-R1, at 5, 19; Tr. 3, at 194-195, 299-300). The Company maintains that while the Attorney General's survivor curves may appear to be plotted more accurately, they are not necessarily more useful for forecasting (Company Brief at 125, citing Exh. NSTAR-JJS-R1, at 5, 19; Tr. 3, at 194-195, 299-300).

Further, the Company contends that the Department recognizes the role of informed judgment and expertise on the part of the preparer of a depreciation study (Company Brief at 125, citing D.P.U. 12-25 at 306; D.P.U. 10-55 at 369. The Company identifies a number of factors relevant to informed judgment, such as asset age, customer requirements, and accelerated plant replacement as part of the GSEP, all of which the Company contends can be factored into a depreciation study (Company Brief at 125, citing Exh. NSTAR-JJS-1, at 13-14; Tr. 3, at 198, 207-210).

In addition, the Company argues that depreciation experts agree that field studies are necessary to form accurate conclusions regarding depreciation (Company Brief at 125, citing Exh. NSTAR Gas-5; Tr. 12, at 989). The Company maintains that the Department has acknowledged the necessity of field inspections in order to consider the underlying physical assets (Company Brief at 125, citing D.T.E. 05-27, at 257-258). The Company asserts that its witness was the only one in this proceeding who obtained the necessary information from management and operating personnel and through a field inspection of representative Company assets (Company Brief at 125, citing Exhs. NSTAR-JJS-1, at 6, 8; AG 2-8; Tr. 3, at 198, 293-294; Company Reply Brief at 51). NSTAR Gas contrasts its efforts with those of the

Attorney General, who the Company claims never attempted to conduct a field inspection of assets (Company Brief at 125-126, citing Tr. 12, at 980). The Company argues that in the absence of information obtained from a field inspection or from Company personnel, any survivor curve recommendation lacks informed judgment and, therefore, is inherently flawed (Company Brief at 126).

ii. Account 303 - Software

NSTAR Gas argues that the Department should reject the Attorney General's proposal to use a longer amortization period for Account 303 (Company Brief at 135). The Company maintains that its proposed five-year amortization period is consistent with both the five-year amortization for this account used in D.T.E. 05-85 and with the five-year amortization it proposes to apply for Account 391.2 Computers (Company Brief at 135, citing Exh. AG-3-7; Company Reply Brief at 55).

iii. Account 367-Mains and Account 380-Services

NSTAR Gas argues that because the Attorney General only considered statistical analysis in examining Account 367-Mains and Account 380-Services, she has not appropriately accounted for the Company's commitment through its GSEP to replace obsolete cast iron and steel mains at an accelerated pace (Company Brief at 126-127, citing Exh. NSTAR-JJS-1, at 19, 21). The Company contends that depreciation rates must recognize not only historical experience but also future expectations (Company Reply Brief at 52, citing D.P.U. 10-55, at 370; D.T.E. 05-27, at 258).

NSTAR Gas also argues that the Attorney General has understated the effect of GSEP-related mains and services replacements on its life estimates (Company Reply Brief at 51-52). The Company maintains that, based on the experience of similar companies for which data are available, its 75-year ASL for Account 367 is already near the upper end of the array of estimates for cast iron, steel, and plastic mains (Company Brief at 126, citing Exh. NSTAR-JJS-1, at 21). The Company contends that because it plans to replace older cast iron and steel mains at an accelerated pace under its GSEP, implementing an ASL that is at or beyond the experience of similar companies would be inappropriate (Company Brief at 126, citing Exh. NSTAR-JJS-1, at 21; Company Reply Brief at 52).

With respect to the Attorney General's arguments regarding the life of plastic pipe, the Company maintains that because plastic pipe has only been in use on gas distribution systems for approximately 40 years, there is no record evidence supporting the Attorney General's claim that plastic pipe will last for over 100 years (Company Reply Brief at 52, citing Exh;. NSTAR-JJS-R1, at 23). The Company contends that based on its own 40 years of historical data relating to plastic pipe, its selected 75-R2.5 survivor curve for Account 367 offers a better fit than the Attorney General proposed survivor curve (Company Reply Brief at 52, citing Exh. NSTAR-JJS-R1, at 24). Further, the Company maintains that given the increasing rate of retirement, the selection of a longer curve to recognize this trend is appropriate and its proposed 54-R2 survivor curve provides an accurate forecast for Account 380 (Company Brief at 127, citing Exh. NSTAR-JJS-1, at 14).

With respect to net salvage, the Company argues that its historic average net salvage for Account 367 has been negative 50 percent as proposed, however, it is less than the negative 70 percent net salvage that it recorded for this account over the last five years (Company Brief at 130, citing Exh. NSTAR-JJS-1, at 48). NSTAR Gas also maintains that while its overall historic average net salvage for Account 380 has been negative 63 percent, over the last five years its net salvage has increased to negative 95 percent (Company Brief at 130, citing Exh. NSTAR-JJS-1, at 56, Tr. 3, at 248-249; Company Reply Brief at 54).

The Company maintains that the Attorney General's recommended salvage factors are flawed and that they understate the recent trend toward an increased negative net salvage (Company Brief at 129). The Company claims that over the past ten years, it has not experienced the negative 35 percent negative net salvage for Account 367 as recommended by the Attorney General (Company Brief at 130, citing Exh. NSTAR-JJS-1, at 48). In addition, the Company contends that the Attorney General's proposed negative 60 percent net salvage factor for Account 380 is lower than both the historic and recent averages (Company Brief at 130-131, citing Exh. NSTAR-JJS-1, at 56). Further, the Company argues that the Attorney General's claims of a trend toward a reduction in negative salvage costs for both Accounts 367 and 380 is misleading because the actual negative net salvage experience has exceeded the estimates of both the Company and the Attorney General over the past five years (Company Reply Brief at 54, citing Exh. NSTAR-JJS-R1, at 50).

Moreover, the Company disputes the Attorney General's claim that recent higher levels of negative net salvage are caused by unusually large retirements of cast iron and bare steel mains and services (Company Brief at 130-131). First, the Company argues that these types of mains and services will continue to be retired each year under its GSEP (Company Brief at 130-131, citing Exh. NSTAR-JJS-1, at 52). Second, NSTAR Gas contends that it will have to replace these types of mains and services in thickly settled areas, which it asserts is an expensive undertaking (Company Brief at 130-131, citing Exh. NSTAR-JJS-1, at 52). Third, the Company contends that, like other gas companies, it has experienced increased costs of removal for a number of reasons, such as with labor, permitting, environmental and safety, and various regulatory costs (Company Brief at 131, citing Exh. NSTAR-JJS-1, at 46; Tr. 3, at 207, 265-266; Company Reply Brief at 53-54). For these reasons, the Company requests that the Department approve its proposed net salvage factors (Company Brief at 131).

Finally, turning to the Attorney General's recommendation that the Company be required to track the type of material associated with additions or retirements of its mains and services, NSTAR Gas maintains that such a study is unnecessary (Company Brief at 136). Specifically, the Company maintains that the Department has previously reviewed NSTAR Gas' depreciation rates without this information (Company Brief at 136).

iv. Account 390 - Structures and Improvements

NSTAR Gas argues that the Attorney General's recommendation to use one retirement method for all Company buildings is not appropriate. Instead, the Company argues that the lifespan method should be used for larger buildings because all of the assets, structures and equipment at these facilities will eventually be retired together at the end of the facilities' useful lives (Company Brief at 127-128, citing Exh. NSTAR-JJS-1, at 30-31). For example, the Company maintains that its Southborough facility was built in 1974 at a cost of approximately $3.5 million and has undergone approximately $17.4 million in various upgrades, including building expansions (Company Brief at 128, citing Exh. NSTAR-JJS-1, at 32). The Company asserts that based on the life span method, the dollar weighted ASL for the entire Southborough facility is approximately 39.5 years (Company Brief at 128, citing Exh. NSTAR-JJS-1, at 34). The Company argues that the Attorney General's proposed life of 50 years is unrealistic because the newer investments in these facilities are projected to have shorter lives than the original facility (Company Brief at 128, citing Exh. NSTAR-JJS-1, at 33).

Further, the Company argues that its selection of a 45-R.1.5 curve for minor office structures was intended to accommodate the large retirement of an entire facility (Company Brief at 128, citing Exh. NSTAR-JJS-1, at 36). The Company contrasts its curve selection with the Attorney General's proposed 50-S0 survivor curve. The Company maintains that the Attorney General's proposed curve is flatter and more suited to a fairly constant rate of retirement each year and, therefore, not to the retirement rate associated with this account (Company Brief at 128, citing Exh. NSTAR-JJS-1, at 36). NSTAR Gas also contends that the Attorney General has misinterpreted the scope of the data from other gas utilities used in the Company's depreciation study. The Company maintains that most of these data are based on life span analysis and not actuarial analysis, as suggested by the Attorney General (Company Reply Brief at 52-53). Based on these arguments, the Company urges the Department to approve as a reasonable estimate of forecasted retirements its proposed life span method for major structures and 45-R1.5 interim survivor curve for minor structures (Company Brief at 128-129).

With respect to net salvage, NSTAR Gas asserts that the Attorney General's salvage analysis erroneously disregards actual historic experience in favor of speculation (Company Brief at 131; Company Reply Brief at 54). In particular, NSTAR Gas argues that the Attorney General incorrectly presumes that the Company will receive significant proceeds from the sale of retired buildings (Company Reply Brief at 55). According to the Company, a retired building is typically no longer useful and, to the extent that there are sales proceeds, most of that value is based on underlying land that is non-depreciable and not included in net salvage calculations (Company Brief at 132, citing Exh. NSTAR-JJS-1, at 60; Company Reply Brief at 55). Further, the Company maintains that net salvage costs associated with improvements made during a structure's useful life are significant and tend to produce an overall negative net salvage (Company Brief at 131, citing Exh. NSTAR-JJS-1, at 59-60; Tr. 3, at 243-244). For all of these reasons, NSTAR Gas asserts that the Department should approve the Company's proposed net salvage factors of negative five percent for major structures and negative 20 percent for minor structures (Company Brief at 132; Company Reply Brief at 55).

v. Account 391.2 - Computers

NSTAR Gas argues that the Attorney General's proposed life for this account is longer than the industry standard (Company Brief at 129, citing Exh. NSTAR-JJS-1, at 39, 42). According to the Company, the vast majority of utilities use an amortization period of five years for these types of assets, with personal computers being somewhat less than five years and other equipment, such as routers, having a longer service life (Company Brief at 129, citing Exh. NSTAR-JJS-1, at 39, 42). The Company maintains that the lifespan of computer servers is relatively short because this equipment is constantly replaced as storage capacity and greater computing power are required[116] (Company Reply Brief at 53). Therefore, the Company requests the Department to approve a five-year amortization period for computer equipment (Company Brief at 129).

[116] The Company also disputes the Attorney General's claim that this account consists primarily of routers and network wiring (Company Reply Brief at 53).

vi. Amortization Reserve Deficiency Adjustment

The Company refutes the Attorney General's contention that allowing recovery of $622,205 annually would amount to double recovery of costs (Company Brief at 132, citing Attorney General Brief at 37). According to NSTAR Gas, the Company implemented amortization accounting for general plant pursuant to its rate settlement in Commonwealth Gas Company, D.P.U. 91-60, at 3-4 (1991) and used a 15-year amortization period[117] (Company Brief at 133, citing Exhs. AG-3-7; AG-2-2; Tr. 1, at 38; Tr. 14, at 1258-1259). Further, the Company maintains that as of year-end 2013 (i.e., the year-end used as the basis of its depreciation study), it had approximately $7.3 million of assets booked to Account 391.2, with vintages ranging from 1999 to 2013 and an accumulated depreciation balance of approximately $3.8 million (Company Brief at 133, citing Exh. NSTAR-JJS-R1, at 38-39). Consequently, the Company argues that even under the Attorney General's definition of "fully accrued" plant, the Company has not fully recovered its investment in Account 391.2 (Company Brief at 133-134, citing Exh. NSTAR-JJS-1, at 40; Company Reply Brief at 56, citing Exh. NSTAR-JJS-1, at 39-40). Therefore, the Company argues that its proposed unrecovered reserve adjustment is necessary in order to guarantee complete recovery of its investment in amortized plant accounts (Company Brief at 133, citing Exh. NSTAR-JJS-1, at 63).

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117 NSTAR Gas disputes the Attorney General's claim that a Company witness referenced a five-year amortization for Account 391.2 (Company Brief at 134-135). The Company argues that the witness was, instead, referring to the amortization of intangible plant and the Company's proposed five-year amortization of depreciation under-accruals (Company Brief at 134-135, citing Tr. 14, at 1258-1260).

Further, the Company argues that the Attorney General's opposition to its proposal to collect its unrecovered reserve is inconsistent with the remaining life method of accounting, in which true-ups are necessary whenever an amortization period is changed (Company Brief at 135, citing Exh. NSTAR-JJS-1, at 66). In this regard, the Company notes that if the amortization period should change, then the Department would require the Company to reconcile that account to ensure full recovery (Company Brief at 135, citing Exh. NSTAR-JJS-1, at 67). For all of these reasons, the Company asserts that the Department should approve a five-year amortization to adjust its unrecovered reserve (Company Brief at 135).

5. Analysis and Findings

a. Standard of Review

Depreciation expense allows a company to recover its capital investments in a timely and equitable fashion over the service lives of the investments. D.T.E. 98-51, at 75; D.P.U. 96-50 (Phase I) at 104; Milford Water Company, D.P.U. 84-135, at 23 (1985); Boston Edison Company, D.P.U. 1350, at 97 (1983). 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 company reaches a conclusion about a depreciation study that is at variance with that witness' engineering and statistical analysis, the Department will not accept such a conclusion absent sufficient justification on the record for such a departure. D.P.U. 92-250, at 64; D.P.U. 905, at 13-15; D.P.U. 200, at 21.

The Department recognizes that the determination of depreciation accrual rates requires both statistical analysis and the application of the preparer's judgment and expertise. D.T.E. 02-24/25, at 132; D.P.U. 92-250, at 64. Because depreciation studies rely by their nature on examining historic performance to assess future events, a degree of subjectivity is inevitable.[118] Nevertheless, the product of a depreciation study consists of specific accrual rates to be applied to specific account balances associated with depreciable property. A mere assertion that judgment and experience warrant a particular conclusion does not constitute evidence. See Eastern Edison Company, D.P.U. 243, at 16-17 (1980); D.P.U. 200, at 20-21; Lowell Gas Company, D.P.U. 19037/19037-A at 23 (1977).

It thus follows that the reviewer of a depreciation study must be able to determine, preferably through the direct filing and at least in the form of comprehensive responses to well-prepared discovery, the reasons why the preparer of the study chose one particular life-span curve or salvage value over another. The Department will continue to look to the expert witness for interpretation of statistical analyses, but will consider expert testimony and evidence that challenges the preparer's interpretation and expects sufficient justification on the record for any variances resulting from the engineering and statistical analyses. Commonwealth Electric Company, D.P.U. 89-114/90-331/91-80 Phase One at 54-55 (1991). To the extent a depreciation study provides a clear and comprehensive explanation of the factors that went into the selection of accrual rates, such an approach will facilitate Department and intervener review.

b. Account 303-Software

The Company proposes a five-year amortization period, with no salvage component, for all software applications booked to Account 303 (Exh. NSTAR-JJS-2, at 49-50). The Attorney General recommends an amortization period of eight years, on the basis that the Company has

[118] This is especially relevant in the calculation of net salvage factors where the cost to demolish or retire facilities cannot be known until the actual event occurs. D.P.U. 92-250, at 66; Boston Edison Company, D.P.U. 1720, at 44 (1984); D.P.U. 1350, at 109-110.

understated the useful life of assets in this account and, thereby, creates an intergenerational inequity (Exh. AG/JP-1, at 67-69).

The amortization period for this type of investment should strike a balance between the need to continue improvements in service technology and the need to maintain intergenerational equity, and may involve consideration of the purpose of the particular application as well as consistency among and between similar applications. D.T.E. 02-24/25, at 153; Boston Gas Company, D.P.U. 93-60-D at 4 (1994). The Company maintains various software applications, a number of which remain in service even after their retirement for plant accounting purposes (Exhs. AG-3-7; AG-14-17, Att.; AG-14-18, Att.). Examination of the Company's retired software indicates that NSTAR Gas used these applications for five to seven years before replacement, with the majority of applications retired (as distinct from fully amortized) after five years (Exh. AG-14-18, Att.).

Despite this apparent uniformity, the majority of these retired software applications represent relatively inexpensive applications costing less than $50,000 (Exh. AG-14-18, Att.). The Company's 13 software applications that remain in use had development costs ranging from $2,932 to $4,439,781, with in-service dates ranging from 1990 through 2006[119] (Exh. AG-14-17, Att.). The Company's three largest software applications make up more than 90 percent of total software costs; the GIS data conversion and gas service mobile data applications have been in service since 2006, and the customer information center software has been in service since 1990

[119] Exhibit AG-14-17 indicates that the Company's customer information system software application package was assigned a 15-year amortization; considering the particular software cost and monthly amortization, the reported 15 years appears to be a typographical error carried forward from a depreciation study conducted in 2004 (Exh. AG-2-22, at 43).

(Exh. AG-14-17, Att.). In view of the length of service associated with NSTAR Gas' software applications, the Department finds that a five-year amortization of assets in this account fails to recognize the Company's actual experience and purpose of these applications, as well as the need for intergenerational equity.

An excessive amortization period would tend to discourage utilities from innovations that serve to improve service to their ratepayers. At the same time, major software applications, such as the Company's customer information system, would be expected to remain in service for a number of years. It would be inappropriate to shift the benefits of such applications from future ratepayers through short amortization periods. D.P.U. 93-60-D at 4.

The Department has examined the software applications in use by NSTAR Gas and has taken into consideration their purpose and development costs (Exh. AG-14-18, Att.). Based on our review, the Department finds that a ten-year amortization represents a reasonable balance between the need to continue improvements in service technology and the need to maintain intergenerational equity. Therefore, the Department will apply an amortization rate of ten percent for Account 303.[120]

c. Account 367-Mains and Account 380-Services

For Account 367, NSTAR Gas proposes to replace the existing 70-R3 curve with a 75-R2 curve which, when combined with a proposed net salvage factor of negative 50 percent, results in an accrual rate of 2.15 percent (Exhs. NSTAR-JJS-2, at 49; NSTAR-JJS-3; NSTAR-JJS-R1, at 3). Alternately, the Attorney General proposes an 80-R2.5 curve with a salvage factor of

[120] Because the information in Exhibit AG-14-18 provides sufficient detail on the useful lives of software booked to Account 303, the Department finds that it is not necessary to require the Company to provide a life estimation analysis, as recommended by the Attorney General, as part of its next rate case.

negative 35 percent for this account (Exh. AG/JP-1, at 10, 52). For Account 380, NSTAR Gas proposes to replace the existing 45-R2 curve with a 54-R2 curve which, when combined with a proposed net salvage factor of negative 75 percent, results in an accrual rate of 2.87 percent (Exhs. NSTAR-JJS-2, at 49; NSTAR-JJS-3; NSTAR-JJS-R1, at 3). The Attorney General proposes a 58-1.5 curve with a salvage factor of negative 60 percent for this account (Exh. AG/JP-1, at 10, 52).

A pure comparison of the actuarial data for Account 367 suggests that an 80-R2.5 curve provides a better statistical fit than the 75-R2 curve, at least for the first 50 years (Exhs. AG/JP-1, at 10; NSTAR-JJS-R1, at 22; Tr. 3, at 196-197). However, because plastic mains were not installed before the 1970s, the data points beyond year 40 are largely composed of cast iron and unprotected steel mains that will be replaced under the GSEP (Exh. NSTAR-JJS-R1, at 22-23). While the Attorney General contends that less than four percent of the mains that will be replaced under the GSEP are cast iron and unprotected steel, most of the older assets to be replaced have vintages of 1924 or newer (Exh. NSTAR-JJS-R1, at 23). Because the Company intends to replace virtually all of these assets over the next ten to 15 years, most of these older assets will be replaced before they reach 104 years in service (Exh. NSTAR-JJS-R1, at 23). In contrast, the Attorney General's proposed ASL presumes that a significant portion of these assets will remain in service beyond 100 years (Exh. NSTAR-JJS-R1, at 23). Consequently, the Attorney General's proposed ASL for Account 367 tends to overestimate the length of time that cast iron and unprotected mains will remain in service (Exh. NSTAR-JJS-R1, at 23). In addition, the actuarial data suggest a trend towards longer lives (Exh. NSTAR-JJS-R1, at 6, 8, 29). Based on these considerations, the Department finds that the use of a 75-R2 curve for Account 367 is reasonable.

The Company proposes a net salvage rate of negative 50 percent for Account 367 (Exh. NSTAR-JJS-1, at 48). The current salvage factor for this account is negative 25 percent (Exh. NSTAR-JJS-R1, at 44). The Company's salvage data for this account indicate negative 50 percent over the period 1992 through 2013, and negative 70 percent over the period 2009 through 2013 (Exh. NSTAR-JJS-2, at 100-101). The Company's three-year rolling averages during this period indicate an overall upward trend in negative salvage in recent years (Exh. NSTAR-JJS-2, at 100-101). This trend, however, may not continue because GSEP-related replacements are influencing retirement activity on this account (Exh. AG/JP-1-Rebuttal at 55-56).

NSTAR Gas demonstrates a relationship between net salvage and average retirement ages through an overall increasing trend for both caused by the effect of inflation on retirement costs (Exh. NSTAR-JJS-R1, at 50-51). The more recent salvage data are influenced by the accelerated retirement of cast iron and bare steel mains and services that, due to their age, currently represent a relatively small portion of undepreciated plant (Exhs. AG/JP-1-Rebuttal, at 55-56, 58, 60–61; AG-2-2, Att).[121] Nevertheless, the Company's GSEP program will affect future retirement activities (Exh. NSTAR-JJS-R1, at 52). Based on these factors, the Department finds that the Company's proposed salvage rate is an appropriate, conservative estimate of the

121 The Company's current inventory of cast iron and bare steel mains and services represents approximately four percent of the current balance for mains and less than 0.5 percent for services (Exhs. AG/JP-1-Rebuttal, at 55-56, 58, 60-61; AG-2-2, Att).

future net salvage associated with Account 367. Therefore, the Department accepts the Company's proposed use of a negative 50 percent net salvage factor for Account 367.

With respect to Account 380, a comparison of the actuarial data for this account suggests that both the 54-R2 curve (as proposed by the Company) and the 58-R1.5 curve (as proposed by the Attorney General) provide good fits to the statistical data (Exhs. NSTAR-JJS-R1, at 26; AG/JP-1, at 10). Because plastic services were not in use before the 1970s, however, the later years represented in the survivor curve have a higher proportion of cast iron and unprotected steel services (Exh. NSTAR-JJS-R1, at 27-28). As these older assets are replaced under the GSEP, the future experience of assets at the end of the survivor curve can reasonably be expected to differ from historical patterns (Exh. NSTAR-JJS-R1, at 28). Moreover, as the Company's GSEP is implemented, it is expected that there will be fewer early retirements and more retirements at later ages; the combination these factors would tend to increase the mode of the survivor curve (i.e., skew the shape of the curve) away from the Attorney General's proposed 58-R1.5 curve towards a curve that more resembles the 54-R2 curve (Exh. NSTAR-JJS-R1, at 29). Based on these considerations, the Department finds that use of a 54-R2 curve for Account 380 is reasonable.

The Company has proposed a salvage factor of negative 75 percent for Account 380 (Exh. NSTAR-JJS-2, at 56). The current salvage factor for this account is negative 80 percent (Exh. NSTAR-JJS-R1, at 44). The Company's salvage data for this account indicate negative 63 percent over the period 1992 through 2013, and negative 95 percent over the period 2009 through 2013 (Exh. NSTAR-JJS-2, at 104-105). The Company's three-year rolling averages for this account demonstrate that an overall upward trend in negative salvage reversed itself during the 2000s, before resuming around 2010 (Exh. NSTAR-JJS-2, at 104-105).

As with Account 367, NSTAR Gas demonstrates a relationship between net salvage and average retirement ages associated with Account 380 through an overall increasing trend for both caused by the effect of inflation on retirement costs (Exh. NSTAR-JJS-R1, at 57-58). The industry data provided by the Company indicate that, after adjusting salvage data for statistical outliers, other gas utilities are experiencing negative salvage of approximately 60 percent for services (Exhs. AG/JP-R1, at 61; AG-2-2, Att.). Because company-specific accounting policies and practices have an effect on net salvage, comparisons of data from individual companies will tend to demonstrate greater variability among net salvage factor estimates than among their life estimates (Exh. NSTAR-JJS-R1, at 46). In view of this information, the Department finds that it is appropriate to adjust the Company’s proposed net salvage factor and decrease it to negative 70 percent.

Application of a R-75.2 curve with negative 50 percent net salvage factor to Account 367 produces an accrual rate of 2.15 percent for this account. Application of a 54-R2 curve with negative 70 percent net salvage factor to Account 380 produces an accrual rate of 2.79 percent for this account. Accordingly, the Department directs the Company to apply a depreciation accrual rate of 2.15 percent to Account 367, and a depreciation accrual rate of 2.79 percent to Account 380.

Finally, the Attorney General recommends that the Department direct the Company to identify the material types of its mains and services when tracking plant additions and retirements in order to aid in establishing ASLs and salvage costs (Attorney General Brief at 37).

The Company objects to the additional burden of this type of accounting, adding that the Department has evaluated depreciation expense without this added procedure (Company Brief at 136).

The Department has acknowledged 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. The ongoing retirement of cast iron and bare steel mains in favor of plastic mains would also be expected to affect the ASL for the distribution mains account. Consequently, the Department has recognized that the continued use of a composite ASL may no longer provide a reliable indication of the actual service lives associated with newer mains. D.T.E. 03-40, at 294; see also D.P.U. 93-60, at 185. Therefore, the Department finds that an identification of the material types of a company's mains and services is now appropriate to establish ASLs and salvage costs. Accordingly, each gas distribution company shall submit a gas main material analysis, along with proposed material-specific accrual rates, as part of its next depreciation study. D.T.E. 03-40, at 294; D.T.E. 02-24/25, at 134, n.62; D.T.E. 01-56, at 95.

d. Account 390-Structures and Improvements

For major structures in Account 390, NSTAR Gas proposes to apply a lifespan analysis, using a 60-year life span for its Southborough office and a 65-year life span for its Summit office, in conjunction with a 100-S1.5 interim survivor curve (Exh. NSTAR-JJS-2, at 49-50, 134-135). When combined with a proposed net salvage factor of negative five percent, the resulting accrual rate is 2.97 percent (Exhs. NSTAR-JJS-2, at 49-50; NSTAR-JJS-3). For minor structures in this account, NSTAR Gas proposes to replace the existing 45-R3 curve with a 45-R1.5 curve which, combined with a proposed net salvage factor of negative 20 percent, results in an accrual rate of 2.94 percent (Exhs. NSTAR-JJS-2, at 49; NSTAR-JJS-3; NSTAR-JJS-R1, at 3). Alternately, the Attorney General proposes a 50-S0 curve with a salvage factor of positive 50 percent for both major and minor structures (Exh. AG/JP-1, at 10, 52).

Use of the life span method for a utility building requires the consideration of factors such as service crew response times, future customer load growth centers, staffing needs, and business functions (Exh. AG-14-14). The estimation process must also take into consideration interim retirements because interim retirements, by their nature, will reduce the average life of the overall elements at the facility (Exh. NSTAR-JJS-R1, at 33).

Approximately 75 percent of the Company's Account 390 balance is associated with the Southborough office and approximately 93 percent of the account balance represents buildings classified by NSTAR Gas as major facilities (i.e., the Southborough and Summit offices) (Exhs. NSTAR-JJS-2, at 49; NSTAR-JJS-R1, at 33; AG-2-30, Att.). Facilities such as these exhibit a general pattern of initial construction, interim additions and retirements through renovations or remodeling, and final retirement of all building elements at the same time regardless of their installation dates (Exh. NSTAR-JJS-R1, at 32-33, 61). Single-location assets of this type are well-suited for the life span method. D.P.U. 12-25, at 315; D.P.U. 92-250, at 65-66. Therefore, the Department will apply the life span method to determine the appropriate depreciation accrual rates for the Company's Southborough and Summit offices.

The pattern of interim additions and retirements associated with the Company's Southborough office indicates that, while the structures themselves may well have useful lives beyond 60 or 65 years, the overall average life of the assets at each of these facilities will be shorter because of interim additions and retirements (Exh. NSTAR-JJS-R1, at 32). Nevertheless, a significant portion of the assets associated with Account 390 represent long-lived assets such as structural elements, and the Company's experience with its Worcester general office suggests that this type of facility could be in service for at least 65 years (Exhs. AG-2-20; AG-2-30; AG-14-14). Based on these considerations, the Department finds that it is appropriate to increase in the service life of the Southborough facility to 65 years, consistent with the anticipated service life of the Company's Summit facility.

Turning to the minor buildings in Account 390, these structures consist of operations facilities such as office space, gas regulating buildings, and warehouses (Exhs. AG-2-30, Att.; AG-12-23). Both the Company's proposed 45-R1.5 curve and the Attorney General's 50-S0 curve appear to produce similar results, particularly during the first 40 years (Exhs. NSTAR-JJS-R1, at 35; AG/JP-Rebuttal at 18). The Attorney General's curve selection for this account, however, is relatively flat and presumes a fairly constant rate of retirements, particularly in the later years (Exh. NSTAR-JJS-R1, at 36). Moreover, the retirement of an entire building will produce a large retirement, suggesting the use of a higher mode curve such as the R1.5 curve. While the presence of early retirements in the data warrants closer examination as to their reasons, the Department finds it appropriate to consider all factors, including such early retirements, in the evaluation of service lives (Exh. NSTAR-JJS-2, at 89).

Based on the above considerations, the Department finds that NSTAR Gas has adequately substantiated its judgment that the results of the statistical analyses warrant the use of its proposed 45-R1.5 curve for this account. Accordingly, the Department will apply a 45-R1.5 curve to Account 390.

NSTAR Gas proposes a net salvage factor of negative five percent for major structures based on common industry practice, and a net salvage factor of negative 20 percent for minor structures based on historic data for this account (Exh. NSTAR-JJS-1, at 59-60; Tr. 3, at 231). The Attorney General recommends a net salvage factor of 50 percent for all structures (Exh. AG/JP-1, at 10).[122]

The Company's salvage data for Account 390 indicate negative 19 percent net salvage over the period 1992 through 2013, and negative 45 percent net salvage over the period 2009 through 2013 that is not expected to continue in the future (Exhs. NSTAR-JJS-2, at 112-113; AG-12-11). The three-year rolling average indicates declining net salvage costs during the early 2000s, with a trend thereafter towards increasing negative salvage costs (Exh. NSTAR-JJS-2, at 112-113).

While the data indicate that only $1,573 in salvage proceeds were realized over the period 1992 through 2013, the Company excluded from its salvage analysis the 2002 sale of a Cambridge building that generated $814,355 in positive net salvage, as well as the 2000 sale of its Plymouth service center that generated a positive 705 percent net salvage (Exhs. NSTAR-JJS-2, at 112; NSTAR-AG-1-21; AG-2-17, Atts. (a), (b); AG-14-13). The Company considers these sales to be outliers (Exhs. AG-2-17; AG-12-12; Tr. 3, at 242). The Department finds, however, that they represent retirements that should be taken into consideration. To the extent that a company considers data to be unrepresentative, such information should be presented in the depreciation study with appropriate narrative as to the applicability of such information.

122 The Company owns the buildings booked to Account 390; leasehold improvements associated with leased facilities are booked to Account 390.1 (Exh. NSTAR-JJS-2, at 49).

The Company's experience with its former Cambridge and Plymouth offices suggests that larger facilities, such as the Southborough and Summit offices, will realize positive salvage values (Exh. AG-2-17, Atts. (a), (b)). While NSTAR Gas maintains that a retired building has little remaining value apart from the associated land, the Department is unpersuaded that significant facilities, as exemplified by the Southborough and Summit offices, have little or no potential for reuse upon their retirements. Accordingly, the Department finds that the Company's proposed net salvage factor for major buildings in Account 390 is significantly understated. Based on the Company's actual experience with larger structures and the inherent element of subjectivity associated with determining salvage factors, the Department finds that it is appropriate to adjust the Company's proposed net salvage factor for major buildings in Account 390 to 20 percent.

While the Company's minor buildings exhibit the same general life cycle as major buildings (i.e., initial construction, interim additions and retirements, and final retirement), some of the structures in this account are industrial-type facilities such as warehouses and garages, and are located in industrial areas (Exh. NSTAR-JJS-R1, at 59). Because of their specialized nature and locations, these facilities are more likely to be demolished upon retirement (Exh. NSTAR-JJS-R1, at 59-60). Based on the nature of structures in this account, as well as the Company's actual experience with Account 390, the Department finds that it is appropriate to adjust the Company's proposed net salvage factor for minor buildings in Account 390 to negative five percent.

Application of a 65-year life span analysis with a 20 percent net salvage factor to major buildings in Account 390 produces an accrual rate of 2.13 percent for this account. Application of a 45-R1.5 curve with negative five percent net salvage factor to minor buildings in Account 390 produces an accrual rate of 2.33 percent for this account. Accordingly, the Department directs the Company to apply a depreciation accrual rate of 2.13 percent to major buildings in Account 390, and a depreciation accrual rate of 2.33 percent to minor buildings in Account 390.

e. Account 391.2-Computers

The Company proposes a five-year amortization period for Account 391.2, while the Attorney General recommends an amortization period of seven years (Exhs. NSTAR-JJS-1, at 49; AG/JP-1, at 10). The Attorney General argues that almost all of the plant associated with this account represents equipment other than personal computers and suggests that most of the investment is related to equipment with longer useful lives than personal computers (Exhs. AG/JP-1, at 47; AG/JP-Rebuttal at 19).

Because of the number and small dollar values attached to assets in this account, as well as the retirement of assets in this account for reporting purposes after the end of the amortization period, there are no actuarial analyses associated with amortized plant (Exh. NSTAR-JJS-R1, at 37-38). The Department has previously accepted service lives of five years for computer equipment. D.P.U. 08-27, at 105, 122-123; NSTAR Merger, D.T.E. 06-40, at 78 (2006). The data provided by NSTAR Gas shows that a majority of utilities apply a five-year amortization to these types of assets (Exhs. NSTAR-JJS-R1, at 39-42; AG-2-2, Att.). While individual items may have lives shorter than five years, other equipment may have lives longer than five years. For these reasons, the Department accepts the Company's proposed amortization period of five years for Account 391.2

f. Amortization Reserve Deficiency Adjustment

The Company proposes a five-year amortization of what it considers to be $3,111,026 in under-accruals in its general plant accounts (Exh. NSTAR-JJS-2, at 11, 50). The Attorney General argues that the Company's proposed amortization should be disallowed on the basis that: (1) the Company has failed to demonstrate that the 15-year amortization of general plant had been approved as part of the settlement in D.P.U. 05-85; (2) the Company' testimony on this matter is contradictory; and (3) Account 391.2 is already fully accrued (Attorney General Brief at 36-37, citing Exh. AG/JP-1, at 72-73; Tr. 1, at 38-39; Tr. 3, at 278-279).

An accrual rate must be sufficient to permit a company to recover its original capital investment over the productive life of the asset, while avoiding placing the financial burden solely on current or future customers. D.T.E. 98-51, at 76. Where the Department determines that under-accruals have developed because of neglectful practices of management, ratepayers should not bear the financial burden of such negligence. Boston Gas Company, D.P.U. 19470, at 49-50 (1978); Wannacomet Water Company, D.P.U. 13525 (1962).

The Company began to apply a 15-year amortization period to general plant booked to Accounts 391 through 398 pursuant to a 1991 rate settlement. D.P.U. 91-60, at 3-4. In 2005, the Company commissioned a new depreciation study that was submitted as part of the rate settlement in D.T.E. 05-85 (Exh. AG-2-22, Att.). In relevant part, the 2005 depreciation study recommended two revisions to the Company's amortization rates: (1) a 20-year amortization for Account 390.1-Leasehold Improvements; and (2) a five-year amortization for Account 391.2-Computers (Exh. AG-2-22, Att. at 43, 115-129). Because the settlement in D.T.E. 05-85 was approved by the Department, the depreciation study submitted in that proceeding was never litigated. Consequently, the Company has continued to apply the 15-year amortization approved in D.P.U. 91-60 to the present date (Exhs. NSTAR-JJS-3, at 2, AG-1-24; AG-3-18).

Based on this history, the Department finds that the Company has applied an amortization period of 15 years for general plant since 1991. Moreover, based on our review of the testimony, we find that the Company's cost of service witness was referring to the amortization of intangible plant in proposing a five-year amortization of depreciation under-accruals, not to the amortization of general plant as claimed by the Attorney General (Tr. 3, at 38-39; Tr. 14, at 1258-1260). On this basis, the Department finds that there is no contradiction in the evidentiary record regarding the amortization period associated with general plant.

There is no indication that depreciation under-accruals existed for these accounts in the years subsequent to the settlement in D.P.U. 91-60, as evidenced by a recommendation in the 2005 depreciation study that the 15-year amortization be maintained for all but two of the general plant accounts (Exh. AG-2-22, Att. at 43). Of the reported $3,111,026 in under-accruals, $2,011,742 represents under-accruals associated with Account 391.2-Computers (Exh. NSTAR-JJS-2, at 50). This under-accrual is attributable to the change from a 15-year amortization to a five-year amortization. Similarly, the under-accruals in Accounts 391.1, 393, 397, and 398, as well as the over-accrual in Account 394, are attributable to the Company's changes in the respective amortization rates and are not the result of any imprudent actions on the part of NSTAR Gas[123] (Exh. NSTAR-JJS-R1, at 63-64). Accordingly, the Department finds

123 Given the recommendations of the 2005 depreciation study to significantly increase the amortization rate for Account 391.2, the Company was at least generally aware by 2005 that the 15-year amortization rate for this account was inadequate (Exh. AG-2-22, Att. at 43). There is, however, no evidence as to the amount of the under-accrual, or whether such an under-accrual would have necessitated corrective action by the Company.

that NSTAR Gas has correctly calculated the under-accruals associated with its general plant accounts. In reaching this conclusion, the Department finds that the Company's proposed amortization rates for Accounts 391 through 398 are reasonable and supported by the evidence (Exh. NSTAR-JJS-2, at 44-45, 138-144; AG-3-18; AG-3-19).

The Department has examined NSTAR Gas' proposed method to eliminate its amortization under-accruals. The remaining lives of general plant assets booked to Accounts 391.1, 391.2, 393, 394, 397, and 398 range from 2.7 years for Account 391.2 to 21.4 years for Account 394, with a dollar-weighted overall average of 11.3 years (see Exh. NSTAR-JJS-2, at 49). In view of this range, the Department finds that a five-year amortization is excessive. Instead, the Department finds an amortization period of eight years strikes a reasonable balance between the need to eliminate the under-accruals and the need for intergenerational equity among current and future customers. See D.P.U. 08-27, at 123; D.T.E. 98-51, at 76-77. Accordingly, the Department will apply an eight-year amortization to the under-accrual of $3,111,026, producing an annual amortization of $388,878 for its general plant under-accruals.

g. Conclusion

In order to calculate the Company's annual depreciation expense based on the revised accrual rates for Accounts 380 and 390, the Department has applied the accrual rates approved by this Order to the Company's depreciable plant balances included in rate base. As discussed in Section IV.B.6.f.iii, above, the Department has allowed the inclusion of most of the Company's post-test year plant additions, but also has excluded from rate base $119,928 booked to Account 303; $4,325,538 booked to Account 367; $4,762 booked to Account 369; $1,331,738 booked to Account 380; $784,048 booked to Account 390; and $119,359 booked to

Account 391; these amounts have been excluded from the depreciable and amortizable plant balances used to derive the Company's pro forma depreciation expense. Finally, the Department has reduced the amortization reserve deficiency adjustment from the Company's proposed $622,205 to $388,878. Based on this analysis, the Department finds that the Company's annual depreciation expense is $25,755,780.[124] Accordingly, the Company's proposed depreciation expense is reduced by $1,276,690.

F. Advertising Expense

1. Introduction

During the test year, NSTAR Gas booked $425,202 in advertising expense (Exh. NSTAR-MFF-2, Sch. MFF-7 (August 21, 2015)). The Company removed from its proposed revenue requirement $269,911 in test year advertising costs associated with its HHPP business, consistent with its decision to sell that business (Exhs. NSTAR-MFF-1, at 21; NSTAR-MFF-2, Sch. MFF-7 (August 21, 2015)). Of the remaining $155,291 in advertising costs, the Company proposes to reduce its test year expense by $72,827 to reflect the removal of expenses related to corporate initiatives or corporate imaging (Exhs. NSTAR-MFF-1, at 21; NSTAR-MFF-2, Sch. MFF-7 (August 21, 2015); Tr. 2, at 154-155). As a result of these

124 As noted above, the Company's depreciation study disaggregates general structures booked to Account 390 among two subaccounts, and disaggregates office furniture and equipment booked to Account 39 among four subaccounts. In order to calculate the depreciation expense for these accounts, the Department has allocated $3,815,322 in 2014 plant additions booked to Account 390 on the basis of the subaccount ratios provided in the Company's depreciation study, and has allocated $35,635 in 2014 plant additions booked to Account 391 to subaccounts 391 (office furniture and equipment) and 391.2 (computers) on the basis of the subaccount ratios provided in the depreciation study.

adjustments, the Company proposes to include in its cost of service $82,464 in advertising expense (Exhs. NSTAR-MFF-1, at 21; NSTAR-MFF-2, Sch. MFF-7 (August 21, 2015)).

2. Positions of the Parties

The Company argues that its advertising expense proposal is consistent with Department precedent (Company Brief at 89, citing Exh. NSTAR-MFF-1, at 21; Tr. 2, at 152; D.T.E. 05-27, at 213). In particular, the Company states that it removed all advertising costs associated with its HHPP business to reflect the sale of that business (Company Brief at 89, citing Exh. NSTAR-MFF-1, at 21). Based on the above, the Company asserts that the Department should approve its proposed advertising adjustment (Company Brief at 89). No other party commented on the Company's proposed adjustment.

3. Analysis and Findings

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; Bay State Gas Company, D.P.U. 92-111-A at 8 (1993). Exempt from this provision, however, is advertising "which relates to any explanation or justification of existing or proposed rate schedules, or notification of hearings thereon 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 government agency." G.L. c. 164, § 33A.

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.[125] D.P.U. 96-50 (Phase I) at 64; D.P.U. 92-111, at 182-191; The Berkshire Gas Company, D.P.U. 90-121, at 130-136 (1990). The Department further separates the promotional class into the following: (1) advertising that promotes the use of gas explicitly in competition with an unregulated fuel; (2) advertising that promotes the use of gas but does not explicitly reference an unregulated fuel; and (3) advertising that promotes non-utility 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.[126]

NSTAR Gas categorizes advertising expenses into three groupings: informational, promotional, and other/miscellaneous expenses (Exh. NSTAR-MFF-2, Sch. MFF-7 (August 21, 2015); Tr. 2, at 152). As noted above, the Company removed all advertising expense associated with its HHPP business (Exhs. NSTAR-MFF-1, at 21; NSTAR-MFF-2, Sch. MFF-7 (August 21, 2015); AG-1-73, Att. (a)). Further, the Company removed advertising expense related to corporate initiatives or imagining (Exhs. NSTAR-MFF-1, at 21; NSTAR-MFF-2, Sch. MFF-7 (August 21, 2015); AG-1-73, Att. (c)). The remaining advertising expense is classified as promotional in nature (Exh. NSTAR-MFF-2, Sch. MFF-7 (August 21, 2015); AG-1-73, Att. (b)).

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125 The Department recognizes additional advertising categories such as political advertising, which is explicitly precluded from rate recovery under G.L. c. 164, § 33A, and conservation-related advertising, which is permitted. D.P.U. 92-210, at 99 n.56.

126 The Department has long-recognized the difficulties associated with determining the eligibility of advertising expense for rate recovery. As we noted in D.T.E. 03-40, at 277, the review process is akin to "commanding haystacks to render up their needles."

The Department has examined the evidence regarding the Company's proposed advertising expense, including the supporting advertising materials (Exhs. NSTAR-MFF-2, Sch. MFF-7 (August 21, 2015); NSTAR-MFF-5 WP 7 (August 21, 2015); AG-1-73, Att. (b); Tr. 2, at 155-157; RR-DPU-8). These advertisements inform consumers of and encourage the use of products or services that are subject to direct competition from products or services of entities not regulated by the Department (e.g., oil). Therefore, the costs associated with these advertisements are eligible for recovery in rates. See D.T.E. 05-27, at 217; D.P.U. 92-111, at 186; D.P.U. 90-121, at 133. Accordingly, the Department accepts NSTAR Gas' proposed adjustments to its test year cost of service.

G. Lease Expense

1. Introduction

The Company booked $389,658 in lease expense during the test year associated with two leases (Exh. NSTAR-MFF-2, Sch. MFF-18, at 1 (August 21, 2015)). The first lease is for office space at the Prudential Center in Boston that is used to house executive, legal, and corporate relations personnel of NUSCO, all of whom provide services to NSTAR Gas (Exh. NSTAR-MFF-1, at 38; Tr. 2, at 151). The lease at the Prudential Center runs through November 2017, with an annual lease expense of $1,463,532, plus applicable operating costs and real estate taxes (Exhs. NSTAR-MFF-1, at 38; NSTAR-MFF-2, Sch. MFF-18, at 2 (August 21, 2015); AG-1-64, Att. (c) at 1). The Company reports that adjusted 2013 operating costs, plus 2014 operating costs and real estate taxes, totaled $231,621, for a total occupancy cost of $1,695,153 (Exhs. NSTAR-MFF-1, at 38; NSTAR-MFF-2, Sch. MFF-18, at 2 (August 21, 2015)). NSTAR Gas was allocated 12.67 percent of this amount, or $214,708, based on a common company allocator that equally weighs total operating revenues and capitalization (Exhs. NSTAR-MFF-1, at 38; NSTAR-MFF-2, Sch. MFF-18, at 2 (August 21, 2015); DPU-12-3 & Att.).

The second lease is for a service center located in Hyde Park that the Company shares with NSTAR Electric Company (Exh. NSTAR-MFF-1, at 38). The lease at the Hyde Park facility runs through July 15, 2018, with an annual lease expense of $338,688, plus applicable real estate taxes (Exhs. NSTAR-MFF-1, at 38; NSTAR-MFF-2, Sch. MFF-18, at 2 (August 21, 2015); AG-1-64, Att. (b) at 1). The Company reports that the real estate bills for the last two quarters of 2014 and the first two quarters of 2015 totaled $62,427, for a total occupancy cost of $401,115 (Exhs. NSTAR-MFF-1, at 38; NSTAR-MFF-2, Sch. MFF-18, at 2 (August 21, 2015)). NSTAR is allocated 55 percent of this amount, or $220,613, based on the amount of the Company's square footage occupancy of the building (Exhs. NSTAR-MFF-1, at 38; NSTAR-MFF-2, Sch. MFF-18, at 2 (August 21, 2015); DPU-12-4).

The total expense related to these two leases and allocated to NSTAR Gas is $435,322 ($214,708 plus $220,613) (Exhs. NSTAR-MFF-1, at 38; NSTAR-MFF-2, Sch. MFF-18 (August 21, 2015)). The Company proposes to increase its test year level of lease expense by $45,664 (Exhs. NSTAR-MFF-1, at 37-38; NSTAR-MFF-2, Sch. MFF-18 (August 21, 2015)).

2. Positions of the Parties

NSTAR Gas argues that both the Prudential Center and Hyde Park facilities provide services to the Company, and that the proposed adjustments are known and measurable, and reasonable in amount (Company Brief at 105, citing Tr. 2, at 151). Therefore, the Company argues that the Department should approve its proposed lease expense adjustment

(Company Brief at 105). No other party commented on the Company's proposed adjustment.

3. Analysis and Findings

A company's lease expense represents an allowable cost that qualifies for inclusion in its overall cost of service. D.T.E. 03-40, at 171; D.P.U. 88-161/168, at 123-125. Known and measureable 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 applies a standard of reasonableness for inclusion of lease expense in the cost of service. D.P.U. 89-114/90-331/91-80 (Phase I) at 96.

In support of its proposed lease expense, the Company has provided executed lease agreements for the Prudential and Hyde Park facilities and documentation showing related operating costs and real estate taxes (Exhs. DPU-12-3 & Att.; DPU-12-4; AG-1-64, Atts. (b), (c); NSTAR-MFF-2, Sch. MFF-18 (August 21, 2015)). Further, the Company has shown that both facilities will be used by NSTAR Gas throughout the terms of the leases (Exh. NSTAR-MFF-1, at 38; Tr. 2, at 151). Based on our review, we find that the proposed adjustment to NSTAR Gas' lease expense is reasonable and represents a known and measurable change to the Company's test year lease expense. Accordingly, the Department accepts the Company's proposal to increase its cost of service by $45,664.

H. Postage

1. Introduction

During the test year, the Company booked $730,269 in postage expense (Exh. NSTAR-MFF-2, Sch. MFF-15 (August 21, 2015)). The Company states that on

January 26, 2014, the price of first class postage increased from $0.46 to $0.49, or 6.52 percent (Exh. NSTAR-MFF-1, at 35). Therefore, the Company proposes to increase its test year postage expense by 6.52 to percent, or $47,626 (Exhs. NSTAR-MFF-1, at 35; NSTAR-MFF-2, Sch. MFF-15 (August 21, 2015)).

2. Positions of the Parties

The Attorney General argues that the vast majority of the Company's postage is not first class stamped mail, but presorted bulk mail, which costs significantly less than first class mail (Attorney General Brief at 20, citing Tr. 5, at 383-384). According to the Attorney General, the increase in the bulk mail rate as of January 2014 was only 5.88 percent (Attorney General Brief at 20, citing Tr. 5, at 383-384). Thus, the Attorney General asserts that the Department should allow only a 5.88 percent increase in the Company's postage expense (Attorney General Brief at 20). The Company does not contest the Attorney General's position (Company Brief at 99). No other party commented on the Company's proposed adjustment.

3. Analysis and Findings

The Department recognizes postage expense as a legitimate cost of doing business. If a postage rate increase occurs prior to the issuance 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. 08-35, at 108; D.T.E. 05-27, at 194; Massachusetts American Water Company, D.P.U. 88-172, at 23-24 (1989); Massachusetts Electric Company, D.P.U. 800, at 29-30 (1982).

The postage increases that went into effect on January 26, 2014, are known and measurable.[127] Therefore, the Company is eligible for an adjustment to its cost of service.

127 See https://about.usps.com/news/national-releases/2013/pr13_077.htm.

D.P.U. 08-35, at 108; D.T.E. 05-27, at 194. With respect to the amount of the adjustment, during the test year, the majority of the Company's mail was presorted and priced at a bulk rate (Exh. AG-18-14; Tr. 5, at 382-383). The Company acknowledges that the postage rate for bulk mail increased in January 2014 from $0.357 to $0.378, or 5.88 percent (Exh. AG-18-14).

The Company booked $730,269 in postage expense in the test year (Exh. NSTAR-MFF-2, Sch. MFF-15 (August 21, 2015)). A 5.88 percent increase in test year postage expense results in an adjustment of $42,940. Accordingly, the Department will reduce the Company's proposed cost of service by $4,686 ($47,626 minus $42,940).

I. Property Tax Expense

1. Introduction

During the test year, the Company booked $13,541,671 in property tax expense (Exh. NSTAR-MFF-2, Sch. MFF-24, at 1 (August 21, 2015)). NSTAR Gas proposes to increase the test year amount by $2,803,737 to reflect the expected level of property taxes in fiscal year 2016 (Exh. NSTAR-MFF-2, Sch. MFF-24, at 1 (August 21, 2015)).

In order to estimate the fiscal year 2016 property taxes, NSTAR Gas calculated a composite tax rate of 2.522 percent based on fiscal year 2014 tax bills and multiplied that rate by its December 31, 2014, net plant balance of $648,125,424 to arrive at an expected fiscal year 2016 property tax amount of $16,345,408 (see Exhs. NSTAR-MFF-1, at 53-54; NSTAR-MFF-2, Schs. MFF-24, at 2, MFF-28, MFF-29 (August 21, 2015); NSTAR-MFF-5, WP MFF-24 (8/18/15); Tr. 14, at 1245-1246).

2. Positions of the Parties

a. Attorney General

The Attorney General argues that the 2015 tax bills used in the calculation of the composite tax rate include "over-valuations" of the Company's property in Worcester and Westborough (Attorney General Brief at 20). The Attorney General notes that the Company has challenged these valuations at the appellate tax board (Attorney General Brief at 20). The Attorney General argues that the calculation of the composite tax rate should be based on property taxes reflecting the net book value of the property in Worcester and Westborough, excluding the contested valuations (Attorney General Brief at 20). The Attorney General's recommendation results in a composite tax rate of 2.469 percent (Attorney General Brief at 20, citing RR-AG-20). The Attorney General asserts that the Department should use the 2.469 percent composite tax rate in "any future rate determinations to ensure that customers are not double-charged for the contested property valuations" levied by Worcester and Westborough (Attorney General Brief at 20).[128]

b. Company

NSTAR Gas argues that its proposed property tax expense is calculated in a manner that is consistent with Department precedent, as the proposed expense is based on the most recent property tax bills that the Company received from the various municipalities in which it owns property (Company Brief at 113, citing D.T.E. 02-24/25 at 123; D.P.U. 96-50, at 109). The

[128] The Attorney General argues that the Department should use a "2.499 percent" composite rate in "any future rate determinations" but, based on the nature of the Attorney General's argument, this appears to be a typographical error (Attorney General Brief at 20; c.f., RR-AG-20).

Company contends that the Attorney General's recommendation to "normalize" property tax expense by adjusting property taxes assessed by Worcester and Westborough is inconsistent with Department precedent (Company Brief at 113-114). NSTAR Gas claims that customers will not be double charged for taxes levied by Worcester and Westborough because customers will receive the benefit of any tax abatements that result from the Company's challenge of purported overvaluations of property in these municipalities (Company Brief at 114 n. 27).[129]

3. Analysis and Findings

The Department's policy is to base property tax expense on the most recent property tax bills a utility receives from communities in which it has property. D.P.U. 08-35, at 150; D.P.U. 96-50 (Phase I) at 108-109; D.P.U. 86-280-A at 7, 17; Colonial Gas Company, D.P.U. 84-94, at 19 (1984). The Department holds the record in a proceeding open to receive the most current tax bills from cities and towns to the utility. D.P.U. 88-67 (Phase I) at 165-166; D.P.U. 84-94, at 19.

The Company proposes to base its property tax expense on current tax assessments and tax rates, increased by a generalized projection of future increases. The Department has repeatedly rejected the use of projected data to determine a company's municipal tax expenses.[130] D.P.U. 11-01/D.P.U. 11-02, at 280-281; D.P.U. 10-114, at 263; D.P.U. 09-39,

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[129] The Department addresses the Company's abatement efforts in Section IX, below.

[130] The Department notes that in D.P.U. 13-75 and D.P.U. 12-25, it appears that the Company derived its property tax expense based on a composite rate formula. However, neither Order discusses the reasons for this treatment or contains a justification for the departure from the Department's otherwise log-standing precedent. We find that there was no express intention on the Department's part to change its long-standing precedent on property tax expense and, therefore, neither case is dispositive of our treatment of the matter here.

at 244; D.P.U. 08-35, at 150; D.P.U. 96-50 (Phase I) at 109-110. The Company has offered no persuasive reason to depart from our precedent here. Therefore, we decline to adopt the Company's proposed property tax calculation.

Further, we decline to adopt the Attorney General's proposal to adjust the property tax bills received from Worcester and Westborough to account for purported over-valuations of the tax assessments. As discussed further in Section IX below, the appeals process associated with the Company's tax abatement requests for these municipalities is ongoing. Therefore, at this time, the known and measurable amount of property taxes owed by the Company to Worcester and Westborough is the amount billed by the municipalities.

Based on the Company's most recent property valuations, actual property tax rates, and Community Preservation Act assessments, NSTAR Gas' current property taxes payable to municipalities, fire districts, and water districts total $15,319,233 (Exh. NSTAR-MFF-5, WP MFF-24, at 1 (August 21, 2015); Tr. 14, at 1247-1248). This amount is known and measurable and represents a $1,777,562 increase in the test year amount of property tax expense. NSTAR Gas proposed to increase the test year amount by $2,803,737. Accordingly, we will reduce the Company's proposed cost of service by $1,026,175 ($2,803,737 minus $1,777,562).

J. Shareholder Services

1. Introduction

During the test year, the Company booked $88,279 in shareholder services (Exh. AG-1-76). NSTAR Gas states that these costs include items such as transfer agent fees, New York Stock Exchange listing fees, and investor relation costs (Exh. AG-18-56).

2. Positions of the Parties

a. Attorney General

The Attorney General argues that Department precedent requires the removal from the Company's cost of service of shareholder services expenses because such costs benefit shareholders rather than customers (Attorney General Brief at 19, citing Western Massachusetts Electric Company, D.P.U. 89-255, at 62-63 (1990); Western Massachusetts Electric Company, D.P.U. 88-250, at (1989)). Accordingly, the Attorney General asserts that the Department should reduce the Company's cost of service by $88,279, and make any associated inflation, working capital, and bad debt adjustments (Attorney General Brief at 19).

b. Company

The Company argues that although the Department's policy is to exclude shareholder-related expenses from the cost of service, this policy is based on expenses that are specific to shareholders such as shareholder plans and programs, transfer agent fees, annual meeting expenses, and shareholder communications (Company Brief at 115, citing D.P.U. 11-01/D.P.U.11-02, at 309-12; D.P.U. 89-255, at 62-63; D.P.U. 88-250, at 47. According to NSTAR Gas, the Department has acknowledged the potential for companies to recover costs other than traditional shareholder service expenses if such costs are shown to benefit ratepayers (Company Brief at 115, citing D.P.U. 11-01/D.P.U. 11-02, at 312).

NSTAR Gas maintains that the disputed costs incurred by the Company include items such as New York Stock Exchange listing fees, which are distinct from traditional shareholder service expenses and are "necessary and appropriate" to enable the Company to obtain access to capital at reasonable terms (Company Brief at 115, citing Exh. AG-18-56). Thus, the Company asserts that these costs have a direct benefit to ratepayers and should be allowed in the cost of service (Company Brief at 115).

3. Analysis and Findings

The Department's policy is 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. In the test year, NSTAR Gas booked $88,279 to shareholder services (Exh. AG-1-76). The Company itemized this expense into the following categories: (1) Shareholder Services - $52,895; (2) Labor and Employee Benefits - $31,429; (3) Employee Expenses - $3,037; (4) Materials and Supplies - $745; and (5) Miscellaneous - $173 (Exh. AG-1-76).

The amount booked to shareholder services in the test year "include[s] items such as transfer agent fees, [New York Stock Exchange] listing fees, and investor relation costs" (Exh. AG-18-56). The Company argues that, despite Department policy, such items should be eligible for rate recovery because they provide benefit to ratepayers (Company Brief at 115).

The Company has failed to sufficiently itemize the amounts booked to shareholder services or to provide any documentation (receipts, invoices, etc.) to support its description of the nature of these costs and to allow us to assess their purported direct benefit to ratepayers. Accordingly, the Department will exclude shareholder services expenses from the Company's cost of service. See D.P.U. 11-01/D.P.U. 11-02, at 312; D.P.U. 10-70, at 186. The Department will reduce the Company's proposed cost of service by $88,279.

K. Rate Case Expense

1. Introduction

Initially, the Company estimated that it would incur $2,061,881 in rate case expense, but later increased this amount to $2,141,881 to account for inadvertently omitted costs (Exhs. NSTAR-MFF-2, Sch. MFF-16; NSTAR-EHC-6; DPU-1-16). The Company's proposed rate case expense includes costs related to legal representation, contractor costs, expenses associated with producing and filing the rate case, and expert services related to the following: (1) marginal cost study; (2) embedded cost of service study; (3) cost of capital study; (4) depreciation study; (5) employee benefits study; and (6) rate base audit (Exhs. NSTAR-EHC-1, at 21-26; NSTAR-EHC-6).

Based on its final invoices and projected costs to complete the compliance filing,[131] the Company now states that its total rate case expense is $1,707,365 (Exh. NSTAR-MFF-2, Sch. MFF-16 (August 21, 2015)). NSTAR Gas proposes to normalize its rate case expense over nine years (Exhs. NSTAR-MFF-1, at 36-37; NSTAR-MFF-2, Sch. MFF-16 (August 21, 2015); NSTAR-EHC-6). Normalizing the Company's proposed rate case expense of $1,707,365 over nine years produces an annual expense of $189,707 (Exhs. NSTAR-MFF-2, Sch. MFF-16 (August 21, 2015)).

2. Positions of the Parties

The Company states that it sought to contain costs by inviting vendors to participate in a competitive bidding process and then designating an internal review committee to evaluate the

[131] As discussed below, the Company proposes to include the following amounts in rate case expense for work to complete the compliance filing: (1) $25,000 for legal representation; and (2) $7,618 for consulting services related to the marginal and embedded cost studies (Exh. DPU-1-8, Att. (a) at 168, Att. (b) at 45 (Supp. 3)).

bids submitted for each request for proposals ("RFP") based on vendor qualifications, relevant experience, capabilities, personnel, and price (Company Brief at 102, citing Exh. NSTAR-EHC-1, at 22). The Company asserts that it further sought to contain costs by conducting studies internally to the extent resources allowed, such as having in-house personnel prepare the Company's lead/lag study (Company Brief at 102).

The Company states that it selected an outside consultant to perform an independent accounting study of the Company's rate base and Annual Return verification (Company Brief at 103). The Company explains that the merger settlement with DOER approved by the Department in D.P.U. 10-170 required NSTAR Electric to present the Department with an independent accounting study and that the Company elected to extend the study to include NSTAR Gas and HOPCO, as it contends that this would improve the Department's ability to review a fundamental component of the cost of service as well as provide additional transparency (Company Brief at 103, citing Exh. NSTAR-EHC-1, at 13-14; Tr. 2, at 139).

Finally, the Company argues that it updated its rate case expense throughout the proceeding, as is consistent with Department precedent (Company Brief at 104, citing Exh. NSTAR-MFF-2, Sch. MFF-16, at 1 (June 15, 2015)). Thus, the Company argues that, based on the Company's adherence to the Department's standards regarding rate case expense, the Department should approve the recovery of the Company's proposed rate case expense (Company Brief at 104). No other party commented on the Company's proposal.

3. Analysis and Findings

a. Introduction

The Department allows recovery for rate case expense based on two important considerations. First, the Department permits recovery of rate case expense that has been actually incurred and, thus, is considered known and measurable. D.P.U. 10-114, at 219-220; D.P.U. 07-71, at 99; D.T.E. 05-27, at 157; D.T.E. 98-51, at 61-62. Second, such expenses must be reasonable, appropriate, and prudently incurred. D.P.U. 10-114, at 219-220; D.P.U. 09-30, at 227; D.T.E. 98-51, at 58; D.P.U. 95-118, at 115-119; D.P.U. 84-32, at 14.

The overall level of rate case expense among utilities has been, and remains, a matter of concern for the Department. D.P.U. 10-114, at 219-220; D.P.U. 07-71, at 99; D.T.E. 03-40, at 147; D.T.E. 02-24/25, at 192; D.P.U. 93-60, at 145. Rate case expense, like any other expenditure, is an area in which companies must seek to contain costs. D.P.U. 10-114, at 219-220; D.P.U. 07-71, at 99; D.T.E. 03-40, at 147-148; D.T.E. 02-24/25, at 192; D.P.U. 96-50 (Phase I) at 79. All companies are on notice that the risk of non-recovery of rate case expenses looms should they fail to sustain their burden to demonstrate cost containment associated with their selection and retention of outside service providers. D.P.U. 10-114, at 219-220; D.P.U. 09-39, at 290-293; D.P.U. 09-30, at 238-239; D.T.E. 03-40, at 153. Further, the Department has found that rate case expenses will not be allowed in cost of service where such expenses are disproportionate to the relief being sought. D.P.U. 10-114, at 219-220; D.P.U. 10-55, at 323; see also Barnstable Water Company, D.P.U. 93-233-B at 16 (1994). Moreover, in its continuing scrutiny of the overall level of rate case expense, the Department may require shareholders to shoulder a portion of the expense. D.P.U. 10-114, at 219-220; D.P.U. 08-35, at 135.

b. Competitive Bidding

i. Introduction

The Department has consistently emphasized the importance of competitive bidding for outside services in a petitioner's overall strategy to contain rate case expense. See, e.g., D.P.U. 10-114, at 221; D.P.U. 09-30, at 227; D.T.E. 05-27, at 158-159; D.T.E. 03-40, at 148; D.T.E. 02-24/25, at 192. If a petitioner elects to secure outside services for rate case expense, it must engage in a competitive bidding process for these services. D.P.U. 10-114, at 221; D.P.U. 09-30, at 227; D.P.U. 07-71, at 99-100, 101; D.T.E. 03-40, at 153. In all but the most unusual of circumstances, it is reasonable to expect that a company can comply with the competitive bidding requirement. D.P.U. 10-55, at 342. The Department fully expects that competitive bidding for outside rate case services, including legal services, will be the norm. D.P.U. 10-55, at 342.

The requirement of having to submit a competitive bid in a structured and organized process serves several important purposes. First, the competitive bidding and qualification process provides an essential, objective benchmark for the reasonableness of the cost of the services sought. D.P.U. 10-114, at 221; D.P.U. 09-30, at 228-229; D.P.U. 07-71, at 101; D.T.E. 03-40, at 152. Second, it keeps even a consultant with a stellar past performance from taking the relationship with a company for granted. D.P.U. 10-114, at 221; D.P.U. 07-71, at 101; D.T.E. 03-40, at 152. Finally, a competitive solicitation process serves as a means of cost containment for a company. D.T.E. 03-40, at 152-153.

The competitive bidding process must be structured and objective, and based on an RFP process that is fair, open, and transparent. D.P.U. 10-114, at 221, 224; D.P.U. 09-30, at 227-228; D.P.U. 07-71, at 99-100; D.T.E. 03-40, at 153. The timing of the RFP process should be appropriate to allow for a suitable field of potential consultants to provide complete bids, and provide for sufficient time to evaluate the bids. D.P.U. 10-114, at 221; D.P.U. 10-55, at 342-343. Further, the RFPs issued to solicit consultants must clearly identify the scope of work to be performed and the criteria by which the consultants will be evaluated. D.P.U. 10-114, at 221-222; D.P.U. 10-55, at 343.

The Department does not seek to substitute its judgment for that of a petitioner in determining which consultant may be best suited to serve the petitioner's interests, and obtaining competitive bids does not mean that a company must necessarily retain the services of the lowest bidder regardless of its qualifications. D.P.U. 10-114, at 222; D.T.E. 03-40, at 153. The need to contain rate case expense, however, should be accorded a high priority in the review of bids received for rate case work. D.P.U. 10-114, at 222; D.T.E. 03-40, at 153. In seeking recovery of rate case expenses, companies must provide an adequate justification and showing, with contemporaneous documentation, that their choice of outside services is both reasonable and cost effective. D.P.U. 10-114, at 222; D.T.E. 03-40, at 153.

ii. The Company's RFP Process

The Company seeks to include in rates the legal and consulting expenses associated with its: (1) legal representation; (2) marginal cost study; (3) allocated cost of service study; (4) cost of capital and capital structure; (5) depreciation study; and (6) rate base audit and Annual Return verification (Exhs. NSTAR-EHC-1, at 21-26; NSTAR-EHC-6). NSTAR Gas conducted a competitive bidding process for each of the above categories of service providers and received at least two bids in each category (Exhs. NSTAR-EHC-1, at 13-15; 21-26; DPU-1-2; DPU-1-3; DPU-1-4). For the most part, the Company selected service providers that offered the lowest prices for their respective services (Exhs. DPU-1-4, Atts. (a) through (e); DPU-1-5, Att.). Where NSTAR Gas chose service providers that did not offer the lowest prices for their respective services, the Company's primary objective was to select the vendor that would provide high-quality services at a reasonable price in a cost-effective manner (Exh. DPU-1-5). Thus, the Company considered the overall anticipated cost of a provider, in addition to the hourly rates or other individual pricing components, and selected the best cost option in each area (Exh. DPU-1-5). Two of the bidders chosen had the second-lowest total bid, but the Company's evaluation committees ranked them highest among all respondents (Exhs. DPU-1-4, Atts. (a), (d); DPU-1-5, Att.). Neither the Attorney General nor any other party challenges the Company's retention of these attorneys and consultants, or the costs associated with their services. Nevertheless, NSTAR Gas bears the burden to demonstrate that its choice of attorneys and consultants was both reasonable and cost-effective. See D.P.U. 10-55, at 343; D.P.U. 09-30, at 230-231; D.T.E. 03-40, at 153.

Based on our review of the bids, the Company's bid evaluation process, and the invoices provided, we conclude that the Company's choice of attorneys and consultants was both reasonable and cost-effective. As noted above, NSTAR Gas chose the lowest bidder or the best option for the overall cost in each service category. We also find that the Company gave proper consideration to price and non-price factors before selecting the providers that it determined would provide the best combination of price and appropriate quality of service (Exhs. DPU-1-4, Atts.; DPU-1-5, Att.; DPU-1-21; Tr. 2, at 91). For each category, the Company appropriately selected a provider who possesses expertise and experience, knowledge of Department ratemaking precedent and practice, familiarity with the Company's operations, and a comprehensive understanding of the tasks for which it was requested to bid (Exhs. DPU-1-4, Atts.; DPU-1-5, Att.).

In addition, we conclude that NSTAR Gas selected consultants and attorneys that offered the Company adequate cost-control measures. For example, many of the consultants agreed to implement a "not to exceed" price cap on portions of the consultant's work (Exhs. DPU-1-3, Atts.; DPU-1-4, Atts.). With respect to legal services, the selected law firm offered a fee structure that was beneficial to the Company (Exh. DPU-1-3, Att. (i)).

The Company did not solicit bids for the employee benefits study or contractor costs (Exhs. DPU-1-15; DPU-1-16; DPU-1-18). The Department has determined that if a company decides to forgo the competitive bidding process, the company must provide an adequate justification for its decision to do so. D.T.E. 01-56, at 76. For the employee benefits study, the Company stated that the consultant was retained as part of a multijurisdictional benefits study that commenced prior to this proceeding (Exh. DPU-1-15; Tr. 2, at 88). Regarding contractor costs, the Company stated that they were part of an overall award that was competitively solicited and that the rate case expense estimate was based on an annualized cost estimate for work performed by a contractor serving a similar support role on a recent rate case in Connecticut for Connecticut Light & Power (Exh. DPU-1-16; Tr. 2, at 88). In these specific circumstances, the Department finds that conducting separate RFPs for the sake of process, rather than to establish a field of potential bidders and establish price and non-price qualifications, would have been inefficient. See D.P.U. 13-75, at 237; D.P.U. 12-25, at 192; D.P.U. 10-114, at 231; D.P.U. 09-30, at 232. Thus, we find that the Company has provided sufficient justification for forgoing the competitive bidding process in selecting these outside service providers. Going forward, the Department fully expects that competitive bidding for outside rate case services, even consultants with a demonstrated relationship with the Company, will be the norm. D.P.U. 10-55, at 342; D.P.U. 10-114, at 221; D.P.U. 09-30, at 228-229; D.P.U. 07-71, at 101; D.T.E. 03-40, at 152-153.

c. Various Rate Case Expenses

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 the services performed. D.P.U. 10-114, at 235-236; D.T.E. 03-40, at 157; D.T.E. 02-24/25, at 193-194. The Department has reviewed the invoices provided by the Company and finds that the invoices are properly itemized (Exh. DPU-1-8, Atts.). With the exception noted below, we find that the total costs associated with each service provider were reasonable, appropriate, proportionate to the overall scope of work provided, and prudently incurred (Exh. DPU-1-8, Atts.).

The exception to our findings above concerns the Company's request to include the rate base audit conducted for NSTAR Gas and HOPCO as rate case expense. Article III (3) of the DOER Settlement approved in D.P.U. 10-170-B required NSTAR Electric to present the Department with an independent accounting study. The Company chose to extend the scope of the study required for NSTAR Electric to include NSTAR Gas and HOPCO, claiming that this would improve the Department's ability to review a fundamental component of the cost of service as well as provide additional transparency (Company Brief at 103; Exh. NSTAR-EHC-1, at 13-14; Tr. 2, at 138-139). Nevertheless, as beneficial as the study may be, neither the Department nor the terms of the Merger Settlement required the Company to conduct the study for NSTAR Gas or HOPCO.

Further, because this proceeding establishes rates for NSTAR Gas, none of the expenses relevant to HOPCO – including the verification of asset study – are appropriate for recovery as rate case expense here (Exh. DPU-1-8, Att. (c); Tr. 5, at 353-356). Moreover, we find that the expenses are nonrecurring and non-extraordinary and, therefore, not eligible for recovery in rates outside of rate case expense.[132] See, e.g., D.P.U. 1270/1414, at 32-33 (1983). Accordingly, the Department disallows $373,859 from the Company's total requested rate case expense (Exh. NSTAR-MFF-5, WP MFF-16).

d. Fees for Rate Case Completion

The Company has included $32,618 in its proposed rate case expense related to completion of the rate proceeding (Exh. DPU-1-8, Att. (a) at 168, Att. (b) at 45 (Supp.3)). This amount includes fixed fees for: (1) legal representation; and (2) marginal cost study and embedded cost study consulting services. (Exh. DPU-1-8, Att. (a) at 168, Att. (b) at 45 (Supp.3)).

The Department's long-standing precedent allows only known and measurable changes to test year expenses to be included as adjustments to cost of service. D.P.U. 10-114, at 237; D.T.E. 03-40, at 161; D.T.E. 02-24/25, at 195; D.T.E. 98-51, at 61-62. Proposed adjustments based on projections or estimates are not known and measurable, and recovery of those expenses

[132] In addition, expenses of this nature are already recoverable in the context of the Company's overall outside legal fees expense or regulatory expense.

is not allowed. D.P.U. 10-114, at 237; D.T.E. 03-40, at 161-162; D.T.E. 02-24/25, at 196; D.T.E. 01-56, at 75. The Department does not, however, 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.P.U. 10-114, at 237; D.T.E. 03-40, at 162; D.T.E. 02-24/25, at 196. Given an adequate showing of the reasonableness of fixed contracts for services to complete a case after the record closes and briefs are filed, a company may qualify to recover such expenses. D.P.U. 10-114, at 237; D.T.E. 03-40, at 162; D.T.E. 02-24/25, at 196. Documented and itemized proof is a prerequisite to recovery. D.P.U. 10-114, at 237; D.T.E. 03-40, at 162; D.T.E. 02-24/25, at 196. Assuming that the fixed fee agreement is properly supported, the fact that the consultants and the company have agreed to complete the service for a fixed fee gives the Department a level of confidence in the reasonableness of the level of effort and consequent expenditure to carry the case through to the compliance filing. D.P.U. 10-114, at 237; D.P.U. 10-55, at 338.

In its initial fee proposal, the Company's legal counsel agreed to perform the compliance services for a fixed fee (Exh. DPU-1-3, Att. (i) at 4). In its final invoice, legal counsel included that fixed amount to cover compliance services (Exh. DPU-1-8, at 2 & Att. (a) at 1, 168 (Supp.3)). Given the scope of work to complete the compliance phase of this proceeding, we find that this fixed cost is reasonable and supported by sufficient evidence.

For the consulting services related to marginal and embedded cost studies, the Company provided an invoice showing the fixed cost based on the number of hours anticipated to be spent and the billing rate (Exh. DPU-1-8, Att. (b) at 45 (Supp.3)). The Department finds that these fixed costs are reasonable for the services to be provided and supported by sufficient evidence.

e. Normalization of Rate Case Expense

The proper method to calculate a rate case expense adjustment is to determine the rate case expense, normalize the expense over an appropriate period, and then compare it to the test year level to determine the adjustment. D.P.U. 10-55, at 338-339; D.T.E. 05-27, at 163; D.T.E. 03-40, at 163; 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 expense so that a representative annual amount is included in the cost of service. D.P.U. 10-55, at 339; D.T.E. 05-27, at 163; D.T.E. 03-40, at 163; D.T.E. 02-24/25, at 191; D.T.E. 01-56, at 77; D.T.E. 98-51, at 53; D.P.U. 96-50 (Phase I) at 77; The Berkshire Gas Company, D.P.U. 1490, at 33 (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.P.U. 10-55, at 339; D.T.E. 05-27, at 163; D.T.E. 03-40, at 163-164; D.T.E. 02-24/25, at 191; D.P.U. 96-50 (Phase I) at 77.

The Department determines the appropriate period for recovery of rate case expense 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.P.U. 10-55, at 339; D.T.E. 05-27, at 163 n.105; D.T.E. 03-40, at 164 n.77; D.T.E. 02-24/25, at 191. If the resulting normalization period is deemed unreasonable or if the company has an inadequate rate case filing history, the Department will determine the appropriate normalization period based on the particular facts of the case. South Egremont Water Company, D.P.U. 86-149, at 2-3 (1986).

NSTAR Gas proposes a nine-year rate case expense normalization period (Exh. NSTAR-MFF-2, Sch. MFF-16 (August 21, 2015)). The average interval between the Company's last four rate cases is 9.17 years (Exh. NSTAR-MFF-2, Sch. MFF-16

(August 21, 2015)).[133] Accordingly, the Department concludes that the appropriate normalization period for the Company's rate case expense is nine years.

4. Requirement to Control Rate Case Expense

The Department recognizes the extraordinary nature of a base rate proceeding and the associated investment of resources that is required for a petitioner to litigate its case before the Department. We emphasize yet again, however, our concern with the amount of rate case expense associated with base rate proceedings and the need for companies to control these costs. D.P.U. 11-01/D.P.U. 11-02, at 270; D.P.U. 10-55, at 341; D.P.U. 09-39, at 286; D.P.U. 09-30, at 227; D.P.U. 08-35, at 129; D.P.U. 07-71, at 99; D.T.E. 03-40, at 147; D.T.E. 02-24/25, at 192; D.P.U. 93-60, at 145.

The Department will continue to closely scrutinize rate case expense, and the requirement that a rate case petitioner engage in a competitive bidding process for its rate case consultants will be enforced. See Plymouth Water Company, D.P.U. 14-120, at 86-87 (2015); D.P.U. 11-01/D.P.U. 11-02, at 270; D.P.U. 10-55, at 343. We will disallow recovery of rate case expense where a petitioner fails to adhere to Department precedent and cannot demonstrate that its choice of consultants is reasonable and cost effective. See D.P.U. 14-120, at 86-87; D.P.U. 11-01/D.P.U. 11-02, at 270; D.P.U. 10-55, at 343.

There are benefits to shareholders from approval of rate increases and, therefore, the Department has found that it may be appropriate for shareholders to shoulder a portion of the expense. See D.P.U. 11-01/D.P.U. 11-02, at 270; D.P.U. 10-55, at 343; D.P.U. 10-70, at 166;

133 In addition to the current filing, the Company's prior rate case filings were D.T.E. 05-85, D.P.U. 91-60, and D.P.U. 87-122 (Exh. NSTAR-MFF-2, Sch. MFF-16 (August 21, 2015)).

D.P.U. 08-35, at 135. As one means to demonstrate that rate case expense has been contained, the Department has directed all electric and gas companies in future rate case filings to consider proposals for some portion of the rate case expense to be borne by shareholders. D.P.U. 11-01/D.P.U. 11-02, at 270; D.P.U. 10-55, at 343-344.

The Company does not agree that there is a legal basis for the premise that shareholders should be required to bear a portion of rate case expense (Exh. DPU-1-24). Nonetheless, the Company notes that Department precedent to normalize the recovery of rate case expense over a number of years without carrying charges ensures that some portion of rate case expense is borne by shareholders (Exh. DPU-1-24, citing Exh. NSTAR-MFF-2, Sch. 16). According to the Company, in addition to the loss associated with the time-value of money, the Company will lose recovery of uncollected rate case expense to the extent that a subsequent rate case is filed before the normalization period expires (Exh. DPU-1-24).

As discussed above, the Department's practice is to set a normalization period for rate case expense based on the Company's recent rate case experience, thus establishing a representative annual amount of expense to include in rates. D.P.U. 10-55, at 339. Normalization is not intended to ensure a company dollar-for-dollar recovery of a particular regulatory expense. D.P.U. 10-55, at 339; D.P.U. 91-106/91-138, at 20. Rather, the amount in rates is intended to reflect a representative annual level of regulatory litigation expenses. D.P.U. 91-106/91-138, at 20. The Department recognizes that, at times, a company will file a rate case before the interval predicted by the normalization period has elapsed; at other times, the interval between the company's regulatory filings will be longer than the interval assumed in calculating the representative amount reflected in base rates. D.P.U. 91-106/91-138, at 20.

In fact, a company largely controls the amount of its recovery of a normalized expense by deciding when to file a new rate case. For example, if the Department determines that rate case expense should be normalized over four years and a company files a new rate case after only three years (i.e., before the normalization period has run), shareholders will, in effect, bear a portion of the rate case expense because the company has recovered only approximately three-quarters of the amount of rate case expense through rates. On the other hand, if a company chooses to file a new rate case sometime after the four-year normalization period has run, the company will have recovered the anticipated amount of rate case expense during the first four years, and will continue to collect the representative annual amount in rates during the subsequent years. Because base distribution rates are not reconciling, the Department will not readjust the level of recovery to remove those costs from rates. Consequently, the company (i.e., its shareholders) will collect more rate case expense than it incurred.

In this proceeding, NSTAR Gas argues that shareholders will likely bear a portion of rate case expense given the proposed normalization period (Exh. DPU-1-24). As discussed above, whether NSTAR Gas recovers all or a portion of a normalized expense is largely within its control and, if the Company decides to forgo a rate case filing for a number of years in excess of the normalization period, it will collect more rate case expense than it incurred. Further, the Company's normalization argument does not speak directly to cost control.

Nevertheless, we find that the Company has made a satisfactory effort to comply with all of our cost-control mandates in this case, both in terms of competitive bidding and other measures such as "not to exceed" price caps on portions of the consultants' work, discounted consultant rates, and using internal resources to assist and support outside service providers with activities such as data collection and project management (Exhs. DPU-1-3, Atts.; DPU-1-4, Atts.; DPU-1-8, at 1 (Supp.3); DPU-1-21; DPU-1-22). In fact, this is one of the few rate case proceedings in which the Attorney General or other parties did not challenge at least some aspect of the Company's proposed rate case expense. In comparison with other recent rate cases of similar complexity, the Company's estimate of rate case expense was reasonable and, based on the final invoices, the actual rate case expense fell below its initial estimate (Exhs. NSTAR-MFF-2, Sch. MFF-16 (August 21, 2015); NSTAR-MFF-2, Sch. MFF-16). Cf. D.P.U. 10-55, at 313-314 (company initially estimated that it would incur rate case expense of $1,731,840 for Boston Gas/Essex Gas and $897,242 for Colonial Gas, but subsequently proposed total rate case expense of $2,187,216 for Boston Gas/Essex Gas and $1,188,815 for Colonial Gas).

For these reasons, we will not require the Company's shareholders to bear a portion of the rate case expense incurred in this proceeding. We reach this conclusion based on the specific facts of this case and do not establish a universally applicable rule at this time. Nonetheless, we remain concerned with the amount of rate case expense associated with base rate proceedings and fully expect companies to demonstrate they have taken aggressive measures to control these costs. Failure to do so will result in the disallowance of all or a portion of rate case expense.

5. Conclusion

NSTAR Gas has proposed a total rate case expense of $1,707,365 (Exh. NSTAR-MFF-2, Sch. MFF-16 (June 15, 2015). The Department has determined that this amount should be reduced by $373,859 for costs associated with the rate base audit, thereby producing an allowable rate case expense of $1,333,506. Based on these findings, the Department concludes that the correct level of normalized rate case expense is $148,167 ($1,333,506 divided by nine years). Accordingly, the Department reduces the Company's proposed cost of service by $41,540 ($189,707 minus $148,167).

L. Amortization of Goodwill

1. Introduction

In 1999, the Department approved a rate plan for Boston Edison Company, Cambridge Electric Company, Commonwealth Electric Company and Commonwealth Gas Company ("Companies"). D.T.E. 99-19. The rate plan was filed in conjunction with the merger of the foregoing Companies' parent companies, BEC Energy and ComEnergy ("BEC Energy-ComEnergy System merger"). D.T.E. 99-19, at 1. The merging Companies became known as NSTAR. D.T.E. 99-19, at 1.

In D.T.E. 99-19, at 62, the Department approved the recovery of an acquisition premium[134] associated with the merger. The Department found that the Companies had demonstrated that recovery of an acquisition premium estimated at that time to be $500,059,252 was necessary to consummate the merger but that the final acquisition premium amount could not be determined until after the merger. D.T.E. 99-19, at 62. Consequently, the Department directed the Companies to provide the journal entries or a schedule summarizing such entries upon completion of the merger, in sufficient detail so as to determine the actual acquisition premium. D.T.E. 99-19, at 62. The Department also directed the Companies to develop a cost allocation system for transactions among the subsidiaries of BEC Energy and ComEnergy,

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[134] Where a utility is purchased at a price above its depreciated original cost, the acquisition premium is the difference between that price and that cost. The acquisition premium is recorded as goodwill on the balance sheet.

including the allocation of the acquisition premium. D.T.E. 99-19, at 91-94. Finally, the Department approved a 40-year (or 480 month) amortization period for the recovery of the acquisition premium. See D.T.E. 99-19, at 59.

On November 23, 1999, the Companies reported to the Department that the acquisition premium as of September 1, 1999, totaled $477,945,697 (Exh. AG-6-25, Att. (c) at 2, 5). The Companies proposed to allocate the acquisition premium among the affiliates of both BEC Energy and ComEnergy (Exh. AG-6-25, Att. (c) at 5-6). The Companies first revalued ComEnergy's unregulated subsidiaries to $11,881,441, representing their aggregate fair market values net of tax effects as of August 31, 1999 (i.e., immediately prior to the merger), as required by generally accepted accounting principles (Exh. AG-6-25, Att. (c) at 5).
See also D.T.E. 99-19, at 86-87. The $11,881,441 basis adjustment, as well as $8,676,000 in merger costs, were added to ComEnergy's common equity balance as of the date of the merger (i.e., $439,947,850), producing a revised common equity balance for ComEnergy as of September 1, 1999, of $460,507,291[135] (Exh. AG-6-25, Att. (c) at 5). The Companies then subtracted the revised common equity balance of $460,507,291 from the $938,452,988 in total consideration paid for ComEnergy, producing an acquisition premium of $477,945,697 (Exh. AG-6-25, Att. (c) at 5). This amount was allocated among the Companies' regulated utilities based on an equal weighting of the number of customers and distribution revenues, producing an allocation of $90,961,429 (or 19.72 percent) in acquisition premiums to NSTAR Gas (Exh. AG-6-25, Att. (c) at 6).

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135 The basis adjustment of $11,881,441 ensured that a portion of the total acquisition premium was implicitly assigned to ComEnergy's unregulated operations. D.T.E. 99-19, at 87.

As part of the year-end close in 1999, the Companies reconciled and finalized the goodwill calculation, which included updating ComEnergy's common equity balance as of the date of the merger to $442,540,306, and adding a loss contingency of $5,992,297 to the goodwill balance, producing a total goodwill balance of $490,023,538 (Exh. AG-6-25, Att. (d) at 2; Tr. 8, at 741-742). The revised goodwill balance was reallocated among the Companies' regulated subsidiaries, producing a revised goodwill allocation of $69,312,933 (or 14.14 percent) to NSTAR Gas (Exh. AG-6-25 & Att. (d) at 3). The Companies submitted their calculations to the FERC on April 2, 2001 (Exh. AG-6-25, Att. (d)). FERC authorized the Companies to treat the goodwill as regulatory assets booked to Account 182.3, Other Regulatory Assets (RR-DPU-16, Att. (b)).[136]

2. Company's Proposal

NSTAR Gas reports that from September 1999 through December 2014 (184 months), it recovered $26,565,501 in goodwill amortization (Exhs. NSTAR-MFF-5, WP MFF-22, at 4 (August 21, 2015); DPU-10-1, Att.). Thus, the Company states that the remaining balance of goodwill amortization is $42,747,432 (Exhs. NSTAR-MFF-5, WP MFF-22, at 4 (August 21, 2015); DPU-10-1 & Att.; Tr. 8, at 742). NSTAR Gas adds to this balance deferred income taxes of $17,184,468 and a tax gross-up of $11,552,100,[137] for a total goodwill regulatory asset of $71,484,000 (Exhs. NSTAR-MFF-5, WP MFF-22, at 4 (August 21, 2015); DPU-10-1, Att.).

136 Account 182.3 is a FERC account. NSTAR Gas continues to record the goodwill for Department accounting purposes to Account 186, Miscellaneous Deferred Debits, as required by the USOA-Gas (Tr. 8, at 759).

137 The goodwill amortization is not deductible for federal or Massachusetts income tax purposes (Exh. NSTAR-MFF-1, at 44; Tr. 8, at 742). Therefore, NSTAR Gas states that it included a tax gross-up to recognize the appropriate tax treatment of the goodwill

The Company states that the remaining amortization amount of $71,484,000, amortized over the 296 months of the 40-year amortization period approved in D.T.E. 99-19 remaining as of December 31, 2014, results in an annual amortization of $2,898,000 (Exhs. NSTAR-MFF-1, at 42; NSTAR-MFF-2, Sch. MFF-22 (August 21, 2015); NSTAR-MFF-5, WP MFF-22, at 4 (August 21, 2015); DPU-10-1, Att.). During the test year, the Company booked $2,851,342 in goodwill amortization (Exhs. NSTAR-MFF-1, at 42; NSTAR-MFF-2, Sch. MFF-22 (August 21, 2015); NSTAR-MFF-5, WP MFF-22, at 4 (August 21, 2015); DPU-10-1, Att.). Therefore, the Company proposes to increase its test year amortization expense by $46,658 (Exhs. NSTAR-MFF-2, Sch. MFF-22 (August 21, 2015); NSTAR-MFF-5, WP MFF-22, at 4 (August 21, 2015); DPU-10-1 & Att.).

3. Positions of the Parties

The Attorney General does not raise any objection to the Company's proposal to include in its cost of service, recovery of the unamortized amount of goodwill approved in D.T.E. 99-19 (see Attorney General Brief at 41-42).[138] The Company reiterated its proposal on brief (Company Brief at 107-108, citing Exh. NSTAR-MFF-1, at 43). No other party commented on the Company's proposed adjustment.

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amortization and to ensure that the Company is able to collect the income tax liability created as a result of the increase in billed revenue necessary to recover the acquisition premium (Exh. NSTAR-MFF-1, at 44; Tr. 8, at 742-743).

138 She contends, however, that NSTAR Gas' proposal to include the unamortized balance of goodwill in the Company's common equity structure is inappropriate and should be rejected (Attorney General Brief at 42-45). This issue is discussed further in Section XII.B below.

4. Analysis and Findings

The Company seeks to amortize $71,484,000 in remaining acquisition premiums over 296 months for an annual amortization expense of $2,898,000 (Exhs. NSTAR-MFF-1, at 42; NSTAR-MFF-2, Sch. MFF-22 (August 21, 2015); NSTAR-MFF-5, WP MFF-22, at 4 (August 21, 2015); DPU-10-1, Att.). The Department has reviewed the Company's calculation of the remaining amortization amount related to the D.T.E. 99-19 acquisition premium (Exhs. NSTAR-MFF-1, at 42; NSTAR-MFF-2, Sch. MFF-22 (August 21, 2015); NSTAR-MFF-5, WP MFF-22, at 4 (August 21, 2015)). Based on our review, the Department finds that the basis adjustment does not include all of ComEnergy's unregulated affiliates. Specifically, the revaluations are confined to Advanced Energy Systems, a combined heat and power facility, and four real estate companies (Exh. AG-6-25, Att. (c) at 5). At the time of the merger, however, ComEnergy also operated ComEnergy Steam, which provided steam service in the City of Cambridge. Cambridge Electric Light Company, D.T.E. 02-76, at 2-3 (2003); Cambridge Electric Light Company, Commonwealth Electric Light Company, Canal Electric Company, D.T.E. 98-78/83, at 6 (1998). The Department questions the Company's implicit assumption that ComEnergy Steam had no market value as of the date of the merger. While the Department will not adjust the Company's calculation of its basis adjustment here, we put NSTAR Gas on notice that this calculation will be the subject of inquiry in the Company's next base rate proceeding.

Moreover, the Company included $5,992,297 in loss contingencies in its goodwill calculation (Exh. AG-6-25, Att. (d) at 2). Loss contingencies represent auditor assessments of potential liabilities based on its evaluation of the underlying assets.[139] Because loss contingencies represent predictions of future probabilities, this type of accounting entry[140] does not represent an element of an acquisition premium that should be borne by ratepayers.[141] Therefore, the Department will exclude the $5,992,297 in loss contingencies from the calculation of goodwill associated with D.T.E. 99-19. This adjustment produces a revised goodwill balance of $484,031,241, of which 14.14 percent, or $68,442,017, is allocable to NSTAR Gas.

The Company had amortized $26,565,501 in goodwill through December 31, 2014, resulting in an unrecovered balance of $41,876,516 as of that date (see Exhs. NSTAR-MFF-5, WP MFF-22, at 4 (August 21, 2015); DPU-10-1, Att.). Based on the current amortization rate, an additional $2,851,342 will have been amortized by the effective date of the rates being authorized by this Order, leaving a remaining unamortized balance of $39,051,274. With the inclusion of an additional 40.2 percent, or $15,688,120, in deferred income taxes and an additional $9,381,456 in associated income taxes, the Company's unamortized goodwill and

139 See "Accounting for Contingencies," FASB Statement of Financial Accounting Standards No. 5, ¶ 1 (FASB Co. #450-10-05).

140 A post-merger reduction in value of assets might be viewed as an improvident investment by shareholders. Regardless of such characterization, this impairment in the value determined by an auditor and booked to goodwill does not result in a restatement of the acquisition premium for Department ratemaking purposes and the associated costs shall not be borne by ratepayers.

141 The Department has long held that neither financial nor tax accounting standards automatically dictate ratemaking treatment. Boston Edison Company, D.P.U./D.T.E. 97-95, at 76-77 (2001); D.P.U. 95-118, at 107; D.P.U. 94-50, at 305; Massachusetts Electric Company, D.P.U. 92-78, at 79-80 (1992); Cape Cod Gas Company, D.P.U. 20103, at 18-19 (1979). Regardless of whether NSTAR Gas is obligated to record loss contingencies for financial reporting purposes, the Company's regulatory accounting and ratemaking standards are established by the Department – not FASB. See G.L. c. 25; G.L. c. 164, § 94.

associated income taxes are $64,120,850 (see Exhs. NSTAR-MFF-5, WP MFF-22, at 4 (August 21, 2015); DPU-10-1, Att.).

The $64,120,850, divided by the remaining amortization period of 284 months[142] as of the effective date of the rates being authorized by this Order, produces a monthly amortization expense of $225,778 or an annual amortization expense of $2,709,336. The Company proposed an amortization expense of $2,898,000 (Exh. NSTAR-MFF-2, Sch. MFF-22 (August, 21, 2015). Therefore, the Department will reduce the Company's proposed cost of service by $188,664.

M. Amortization of Hardship Accounts Arrearage Balances

1. Introduction

Hardship protected accounts are residential service accounts that apply to customers who are protected from shut-off by a utility for non-payment. 220 C.M.R. §§ 25.03, 25.05. To qualify for protected status from service termination, customers must be elderly or demonstrate that they have a financial hardship and meet certain other requirements, such as having a serious illness or residing with a child under twelve months of age. See 220 C.M.R. § 25.03(1); 220 C.M.R. § 25.03(3); 220 C.M.R. § 25.05(3). Customers who meet the income eligibility requirements for the federal Low Income Home Energy Assistance Program are deemed to have a financial hardship. 220 C.M.R. § 25.01(2).

Many such accounts remain in protected status for long periods of time and, during this time, the Company is not permitted to pursue collection or write-off the associated uncollected revenues without incurring a significant charge to equity (see Exh. NSTAR-MFF-1, at 45-46).

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[142] The remaining amortization period is calculated as follows: 296 months remaining as of December 31, 2014 minus twelve months for the period January 1, 2015 to December 31, 2015.

According to NSTAR Gas, its active hardship accounts receivable balances in arrears has grown significantly to over $5.2 million as of October 31, 2014, and the Company has no mechanism to collect the balances (Exh. NSTAR-MFF-1, at 46-48). Of this total, the Company reports that $2,882,049 in active hardship receivables are over 360 days in arrears (Exhs. NSTAR-MFF-1, at 45; NSTAR-MFF-5, WP MFF-22, at 2 (August 21, 2015)). The Company proposes to recover the $2,882,049 over a five-year period, which results in an annual amortization expense of $576,410 (Exhs. NSTAR-MFF-1, at 45-46; NSTAR-MFF-2, Sch. MFF-22 (August 21, 2015); NSTAR-MFF-5, WP MFF-22, at 1 (August 21, 2015)).

2. Positions of the Parties

The Company maintains that because hardship protected accounts cannot be disconnected, the accounts remain active and, therefore, do not become part of the bad debt expense to be recovered from ratepayers (Company Brief at 108). According to the Company, its proposal to amortize the arrearage balance of its hardship protected accounts is consistent with Department precedent (Company Brief at 108, citing D.P.U. 13-90, at 163-167; D.P.U. 10-70, at 214-216). No other party commented on the Company's proposed adjustment.

3. Analysis and Findings

Under current ratemaking practice, there is no cost of service mechanism for the Company to recover the balance of protected hardship accounts receivable. See D.P.U. 10-70, at 210-211 n.12. Unlike expenses that may be deferred for recovery in a subsequent rate case, the balance of protected hardship accounts receivable cannot be recovered in rates unless the asset is deemed impaired and written off. D.P.U. 10-70, at 210-211 n.12. However, because NSTAR Gas' hardship protected accounts remain active, the Company cannot write off the unpaid balance and, therefore, cannot recover the amounts as bad debt expense on a timely basis (Exh. NSTAR-MFF-1, at 45; Tr. 10, at 873-874).

In this case, the record shows that the Company's arrearage balance for such accounts has increased significantly (Exhs. NSTAR-MFF-1, at 46; NSTAR-MFF-5, WP MFF-22, at 2 (August 21, 2015)). While the Company did not describe the reasons for the increase, it stands to reason that expanded eligibility for hardship protection has contributed to the growing arrearage balance. See D.P.U. 13-90, at 163-164, citing Investigation Commencing a Rulemaking Pursuant to 220 C.M.R. § 2.00 et seq., D.P.U. 08-104-A (2009). The Company's total arrearage balance as of October 2014 was over $5.2 million, with over 50 percent of that total attributable to active hardship receivables that are over 360 days in arrears (Exhs. NSTAR-MFF-1, at 45-46; NSTAR-MFF-5, WP MFF-22, at 2 (August 21, 2015)).

We find that the Company's proposal to recover a portion of the active hardship arrearage balance through distribution rates amortized over five years, is consistent with Department precedent. See D.P.U. 13-90, at 163-168; D.P.U. 10-70, at 214-221. By allowing the amortization of a significant level of the protected account outstanding balance, the Department provides assurance to the Company of the probability of recovery, which should alleviate the need to record a significant charge to its income statement or to create any reserve account. See D.P.U. 13-90, at 176; D.P.U. 10-70, at 219. Accordingly, we approve the Company's proposed increase to test year cost of service of $576,410. We direct the Company to credit any subsequent payments made by customers towards the amortized balance to all customers through the LDAC, consistent with our findings in Section XIII.D below.

N. Amortization of ASC 740 Regulatory Asset

1. Introduction

On July 24, 2013, the Legislature passed An Act Relative to Transportation Finance, St. 2013, c. 46 ("Transportation Finance Bill"). In pertinent part, the Transportation Finance Bill repealed G.L. c. 63, § 52A, which provided for a state franchise tax rate of 6.5 percent for public utility corporations (see Exh. NSTAR-MFF-1, at 48). See also G.L. c. 46, § 39.[143] Consequently, utility corporations lost their separate tax status for tax years beginning on and after January 1, 2014, and became subject to the tax rates applicable to corporations pursuant to G.L. c. 63, § 39 (Exh. NSTAR-MFF-1, at 48; Tr. 10, at 867). For NSTAR Gas, the tax rate increased to 8.0 percent (Exh. NSTAR-MFF-1, at 48).

NSTAR Gas states that the increase in the franchise tax rate created an accumulated deferred income taxes deficiency on the Company's books (Exh. NSTAR-MFF-1, at 49). As a result, pursuant to Accounting Standards Codification 740 ("ASC 740"), the Company recorded an additional $2,920,280 in accumulated deferred income taxes liability and grossed-up this amount to $4,883,411 to recognize the tax effect of this liability on the revenue requirement (Exhs. NSTAR-MFF-1, at 49; NSTAR-MFF-5, WP MFF-22, at 3 (August 21, 2015); AG-6-27). The Company proposes to recover the $4,883,411 over a five-year period, which results in an

143 Electric, gas, water, telephone, railroad, and similar businesses within Massachusetts were previously taxed at a rate of 6.5 percent on their net income. G.L. c. 63, § 52A, repealed by G.L. c. 46, § 39 (2013). In contrast, other Massachusetts business corporations pay corporate excise taxes equal to the greater of either: (1) the sum of eight percent on their net income and 0.26 percent of (a) its tangible property or (b) its net worth if it is an intangible property corporation; or (2) $456.00. G.L. c. 63, § 39; see also Milford Water Company, D.P.U. 12-86, at 245 (2013).

annual amortization expense of $976,682 (Exhs. NSTAR-MFF-1, at 49; NSTAR-MFF-2, Sch. MFF-22 (August 21, 2015); NSTAR-MFF-5, WP MFF-22, at 3 (August 21, 2015)).

2. Positions of the Parties

a. Attorney General

The Attorney General argues that, because the majority of the increase in deferred tax liability was property related, the increase in the deferred tax liability was not payable immediately, nor will it be payable over the next five years (Attorney General Brief at 17-18, citing Exh. AG-DJE-1, at 15-16). Rather, the Attorney General contends that the tax liability will be paid back over the remaining life of the property as the property depreciates (Attorney General Brief at 18, citing Exh. AG-DJE-1, at 15-16). Therefore, the Attorney General asserts that the Company's propose use of a five-year amortization period is inappropriate because such a short amortization period would allow the Company to recover the increased income taxes more rapidly than they are actually being paid (Attorney General Brief at 17-18, citing Exh. AG-DJE-1, at 15-16).

The Attorney General argues that, consistent with Department precedent, the appropriate amortization period for the ASC 740 regulatory asset is the estimated remaining service lives of the Company's plant assets (Attorney General Brief at 18-19, citing D.P.U. 13-75, at 269-270; D.P.U. 92-111, at 172-173; Attorney General Reply Brief at 12-13). According to the Attorney General, the average remaining life of the Company's net plant in service as of the end of the test year is 30.6 years (Attorney General Brief at 18, citing Exh. AG-DJE-1, at 16). Amortizing the ASC 740 regulatory asset over 30.6 years reduces the Company's annual amortization to $159,787 (Attorney General Brief at 19). The Attorney General argues that the Company has failed to provide any reason why its proposed amortization period should be accepted in place of established Department precedent (Attorney General Reply Brief at 13).

b. Company

The Company argues that the Attorney General's proposal to amortize its ASC 740 regulatory asset over 30.6 years is incorrect and therefore, should not be accepted by the Department (Company Brief at 109). According to the Company, deferred income tax liabilities are created when an incurred cost is deducted for income tax purposes in a period prior to its recognition as expense for financial reporting purposes (Company Brief at 109, citing Exh. NSTAR-MFF-1, at 48-49). The Company contends that when tax rates change, an imbalance occurs whereby the deferred income taxes are not stated at the new tax rate (Company Brief at 109, citing Exh. NSTAR-MFF-1, at 48-49). Therefore, the Company claims that its accumulated deferred income taxes balance became understated when the corporate tax rate was increased from 6.5 percent to 8.0 percent (Company Brief at 109, citing Exh. NSTAR-MFF-1, at 48-49; Tr. 10, at 867).

The Company argues that its proposed amortization period is appropriate because, if it files a distribution rate case in five years, its deferred income taxes would be fully reinstated at the correct tax rate, which would benefit customers through a reduction in rate base (Company Brief at 110, citing Tr. 10, at 868-869). Further, the Company contends that deferred income taxes account for multiple book-tax timing differences that will reverse over varying timeframes (Company Brief at 110, citing Tr. 10, at 870-871). Accordingly, the Company argues that a five-year reinstatement of those balances, with a corresponding rate base reduction for all customers, is more appropriate than an amortization period which reflects an "average" of one component of the accumulated deferred income taxes balance (Company Brief at 110).

In this regard, NSTAR Gas contends that approximately 26 percent of the accumulated deferred income taxes deficiency is due to non-plant related book-tax timing differences which, according to the Company, can "turn around" as quickly as in one year's time (Company Brief at 110; Company Reply Brief at 50). Therefore, NSTAR Gas asserts that applying an amortization period based on the average remaining life of the Company's existing plant balance would not appropriately apportion the reinstatement of the accumulated deferred income taxes deficiency to customers (Company Brief at 110; Company Reply Brief at 50-51). Finally, the Company suggests that if the Department were to determine that an amortization period based on remaining service life is appropriate, the Department should not rely on the Attorney General's proposed amortization period but, instead, determine the appropriate estimated remaining service life (Company Reply Brief at 50).

3. Analysis and Findings

ASC 740 (formerly Statement of Financial Accounting Standard No. 109 ("FAS 109")) requires companies to recognize on their financial statements all previously unrecorded future income tax liabilities[144] (see Exh. NSTAR-MFF-1, at 48). See also D.P.U. 13-75, at 269; D.T.E. 05-27, at 227. The change in NSTAR Gas' state income tax expense arising from the enactment of the Transportation Finance Bill results in deficiencies in the Company's deferred state income tax reserve (Exh. NSTAR-MFF-1, at 49). The Department has reviewed the

[144] In 2009, as part of a general recodification of the Financial Accounting Standards Board's accounting rulings, FAS 109 became part of ACS 740.

Company's deferred income tax liability calculations and finds them to be accurate (Exhs. NSTAR-MFF-5, WP MFF-22, at 3 (August 21, 2015); AG-6-26 & Att.; AG-6-27). Thus, we find that the Company may recover $4,883,411 in accumulated deferred income taxes as a result of the increase in the franchise tax rate.

With respect to the Company's proposed amortization period, the Company states that its proposed amortization period of five years is intended to reflect a typical time lag between base rate cases and, therefore, would result in the regulatory asset being fully recovered by the time of a subsequent base rate proceeding (Exhs. DPU-10-8; AG-6-28). The Department, however, has found that it is appropriate to recover FAS 109 regulatory assets over an amortization period reflective of the remaining life of the company's utility plant in service at the time, pursuant to the South Georgia method.[145] See, e.g., D.P.U. 13-75, at 269-270; D.T.E. 05-27, at 227-228 n.136; D.P.U. 95-40, at 50; D.P.U. 92-111, at 172-173; Essex County Gas Company, D.P.U. 87-59, at 55-56 (1987). The Company has provided no compelling reasons to depart from this precedent for plant-related items.

Approximately 26 percent of the Company's accumulated deferred income taxes deficiency, however, is due to non-plant related book-tax timing differences, which can be subject to a quicker turnaround than most plant items (Exh. AG-6-26, Att.). The Department

[145] Pursuant to the South Georgia method, accumulated deferred income tax deficiencies resulting from changes in tax rates are recovered on a straight-line basis, by amortizing the deficiency over the remaining regulatory life of the property (Exh. DPU-24-21). This approach is referred to as the "South Georgia" method because it was first prescribed by the Federal Power Commission in South Georgia Natural Gas Company, FPC RP-77-32. D.P.U. 92-111, at 171 n.49; D.P.U. 87-59, at 55-56.

finds that it is appropriate to consider the shorter turnaround associated with non-plant related timing differences in determining the appropriate amortization period in this instance.

NSTAR Gas' net plant balance at the end of 2014 was $650,528,325 (Exh. NSTAR-MFF-2, Sch. MFF-27 (August 21, 2015)). Application of the depreciation accrual rates approved in this Order to the respective plant investment account balances produces a depreciation expense of $25,755,780. Accordingly, we find that the remaining life of the Company's plant is 25.3 years.[146] The Department will apply a five-year amortization period to the 26 percent of non-plant-related accumulated deferred income taxes and a 25.3 year amortization period to the 74 percent of plant-related accumulated deferred income taxes, resulting in a total amortization period of 20.02 years. Thus, the Department finds that the appropriate amortization period for the Company's 740 ASC regulatory asset is 20 years.

Based on the foregoing, the Department approves the Company's recovery of its deferred income tax liability of $4,883,411 over a period of 20 years. Of this amount, $4,055,012 shall be recovered through the Company's base distribution rates. The remaining $828,399 relates to pension/PBOP regulatory assets and shall be recovered through the Company's pension adjustment factor (see Exh, AG-6-26, Att.). See D.P.U. 13-75, at 270.

NSTAR Gas has included the entire $4,883,411 in its distribution rate income tax calculation, producing an income tax adjustment of $976,682 ($4,883,411 over five years) (Exhs. NSTAR-MFF-1, at 49; NSTAR-MFF-2, Sch. MFF-22 (August 21, 2015); NSTAR-MFF-5, WP MFF-22, at 3 (August 21, 2015)). Because only $4,055,012 will be recovered through the Company's distribution rates, the Department finds that the correct income

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146 The $650,528,325 net plant balance divided by a depreciation expense of $25,755,780 results in a remaining life equal to 25.3 years.

tax adjustment is $202,751 ($4,055,012 over 20 years). Accordingly, the Department will reduce NSTAR Gas' proposed income tax adjustment by $773,931. The effect of this adjustment on the Company's income tax expense is presented in Schedule 8 of this Order.

O. Amortization of Deferred Repair Study Costs

1. Introduction

In September 2013, the Internal Revenue Service ("IRS") adopted new regulations governing the tax treatment of amounts paid to acquire, produce, or improve tangible property.[147] The Company states that it expects to receive an incremental tax deduction as a result of the new regulations (Exh. NSTAR-MFF-1, at 50).[148]

In order to fully evaluate the potential benefit of an expected incremental tax deduction on an enterprise-wide basis, NUSCO contracted with Ernst & Young LLP ("Ernst & Young") to perform a study of the new regulations and their impact on the Company and its affiliates (Exhs. NSTAR-MFF-1, at 50; NSTAR-MFF-5, WP MFF-22, at 6-13 (August 21, 2015); RR-DPU-7). On October 13, 2014, Ernst & Young provided to Northeast Utilities a "Statement of Work" that outlined Ernst & Young's responsibilities (Exh. NSTAR-MFF-5, WP MFF-22, at 6-13 (August 21, 2015)). The Statement of Work also provided an estimated study cost of $500,000 to $650,000 (Exh. NSTAR-MFF-5, WP MFF-22, at 11). The Company estimated that

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147 For a summary of the new regulations, see Internal Revenue Bulletin: 2013-43, T.D. 9636 Guidance Regarding Deduction and Capitalization of Expenditures Related to Tangible Property (October 21, 2013), found at: http://www.irs.gov/irb/2013-43_IRB/ar05.html#d0e133.

148 The Company estimated the amount of the tax deduction at approximately $4,000,000 (Exhs. NSTAR-MFF-1, at 61; NSTAR-MFF-2, Sch. MFF-30 (August 21, 2015)). During the course of the proceedings, the Company updated the accumulated deferred income taxes impact to $20.5 million as of year-end 2014 (Exh. NSTAR-MFF-5, WP MFF-30).

its allocated share of the cost of the study would be $100,000 (approximately one-sixth of the expected total cost of the study), given that Ernst & Young would be performing services on behalf of six utilities under the Northeast Utilities umbrella (Exh. NSTAR-MFF-1, at 50; Tr. 2, at 148-150). According to NSTAR Gas, the incremental tax deduction will reduce the Company's cost of service for customers (Exh. NSTAR-MFF-1, at 50). Accordingly, the Company proposes to recover the cost of the study from customers through an annual amortization of $20,000 for five years (Exh. NSTAR-MFF-1, at 50). No party commented on the Company's proposal.

2. Analysis and Findings

NSTAR Gas seeks to amortize $100,000 in expenses related to the Ernst & Young study over a five year period for an annual amortization amount of $20,000 (Exhs. NSTAR-MFF-1, at 50; NSTAR-MFF-5, WP MFF-22, at 3 (August 21, 2015)). The Company readily concedes that the costs associated with the study represent a one-time expense that will not recur on an annual basis (Tr. 2, at 144-145). Further, all costs associated with the Ernst & Young study will be incurred post-test year, as the agreement with Ernst & Young is dated October 13, 2014 (Exh. NSTAR-MFF-5, WP MFF-22, at 6 (August 21, 2015)).

As of early June 2015, the Ernst & Young study had not been completed (see Tr. 2, at 144). The Company did not provide evidence of any actual total costs it has incurred to date related to the study but, instead, provided only an estimated and allocated share of costs based on Ernst & Young's estimate of the total costs (see Exh. NSTAR-MFF-5, WP MFF-22, at 6 (August 21, 2015); Tr. 2, at 149-150). The Department typically does not allow proposed adjustments based on projections or estimates. D.T.E. 98-51, at 62, citing D.P.U. 92-210, at 83; Dedham Water Company, D.P.U. 849, at 32-34 (1982).

Further, the Department permits a company to include an expense in its cost of service if the company can demonstrate that the expense is (1) either annually or periodically recurring; or (2) if non-recurring, is extraordinary in nature. D.P.U. 89-114/90-331/91-80 (Phase I) at 152; D.P.U. 88-250, at 65-66; D.P.U. 1270/1414, at 33. Non-recurring expenses incurred in the test year are ineligible for inclusion in the cost of service unless it is demonstrated that they are so extraordinary in nature and amount as to warrant their collection by amortizing them over an appropriate time period. D.P.U. 1270/1414, at 33. Post-test year expenses of this nature, such as the expenses associated with the Ernst & Young study incurred in 2014 and 2015, may be accorded the same treatment. D.P.U. 1720, at 87-88.

The appropriate standard to determine what constitutes an extraordinary expense is derived from the Department's standard for determining eligibility for deferral accounting, which is based on total operating revenues. D.P.U. 13-75, at 261; see also, Fitchburg Gas and Electric Light Company, D.P.U. 09-61, at 11 (2009); Aquarion Water Company of Massachusetts, D.T.E. 03-127, at 9 (2004); D.T.E. 03-40, at 30; D.T.E. 02-24/25, at 80-81; D.P.U. 93-229, at 7. The Company's total gas operating revenues during calendar year 2013 were $420,324,617 (Exh. NSTAR-MFF-2, Sch. MFF-33, at 9 (August 21, 2015)). Even if the Company could demonstrate that the expense was known and appropriately allocated to NSTAR Gas, a one-time expense of approximately $100,000 for a gas distribution company with annual revenues of approximately $420 million is not extraordinary in amount.

Based on the foregoing, we reject the Company's proposal to include in its cost of service any expenses related to the Ernst & Young study. Accordingly, the Department will reduce the Company's proposed cost of service by $20,000.

P. Inflation Allowance

1. Introduction

In its initial filing, NSTAR Gas proposed an inflation adjustment of $1,238,312 (Exhs. NSTAR-MFF-1, at 39; NSTAR-MFF-2, Schs. MFF-6, MFF-19, MFF-33, at 2). The Company then revised its inflation adjustment to $722,586 based on updated expense reporting (Exh. NSTAR-MFF-2, Schs. MFF-6, MFF-19, MFF-33, at 2 (August 21, 2015)). The Company used the gross domestic product implicit price deflator ("GDPIPD") (as sourced from the Bureau of Economic Analysis and Moody's Analytics) to calculate its inflation allowance (Exhs. NSTAR-MFF-1, at 39; NSTAR-MFF-5, WP MFF-19 (August 21, 2015)). The Company calculated the change in the GDPIPD from the midpoint of the test year to the midpoint of the rate year,[149] to calculate a 4.662 percent inflation factor (Exhs. NSTAR-MFF-1, at 39; NSTAR-MFF-5, WP MFF-19 (August 21, 2015)).

To arrive at its proposed inflation adjustment of $722,586, NSTAR Gas first calculated an adjusted test year expense associated with all O&M expenses of $71,335,401 (Exhs. NSTAR-MFF-2, Sch. MFF-6, at 2 (August 21, 2015); NSTAR-MFF-5, WP MFF-19 (August 21, 2015). NSTAR Gas then removed from its inflation allowance calculation

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[149] The test year is the twelve-month period ending December 31, 2013 (Exh. NSTAR-MFF-1, at 3). The rate year is the period January 1, 2016 through December 31, 2016, and the midpoint of the rate year is July 1, 2016 (Exh. NSTAR MFF-1, at 3, 7).

$55,835,926, which represents adjusted test year expenses associated with the various categories of O&M expense for which it seeks separate adjustments (Exh. NSTAR-MFF-5, WP MFF-19 (August 21, 2015)).[150] Next, NSTAR Gas multiplied the 4.662 percent inflation factor by $15,499,926, which represents the adjusted test year residual expense associated with various O&M expense categories that the Company determined were eligible for an inflation allowance (Exhs. NSTAR-MFF-2, Sch. MFF-6, at 2 (August 21, 2015); NSTAR-MFF-5, WP MFF-19 (August 21, 2015)).[151]

2. Positions of the Parties

The Company argues that its method of calculating an inflation allowance, including the use of the GDPIPD, is consistent with Department precedent (Company Brief at 106-107, citing D.P.U. 13-75, at 251; D.P.U. 08-35, at 154-155; D.T.E. 02-24/25, at 184; D.P.U. 95-40, at 64; D.P.U. 92-250, at 97-98). Thus, NSTAR Gas asserts that the Department should approve the inflation allowance adjustment to the Company's cost of service (Company Brief at 107). No other party commented on the Company's proposed inflation allowance.

3. 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;

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150 These expense categories are: (1) advertising expense; (2) uncollectible expense; (3) computer services; (4) dues and memberships; (5) employee benefits; (6) insurance expense and injuries and damages; (7) payroll expense; (8) variable compensation; (9) postage expense; (10) rate case expense; (11) regulatory assessments; (12) leases expense; and (13) HHPP costs (Exh. NSTAR-MFF-5, WP MFF-19 (August 21, 2015)).

151 These categories include expenses associated with transmission and distribution, customer accounts, sales, and administrative and general (Exh. NSTAR-MFF-2, Sch. MFF-6, at 2 (August 21, 2015)).

D.T.E. 01-56, at 71; D.T.E. 98-51, at 100-101; D.P.U. 96-50 (Phase I), at 112-113; D.P.U. 95-40, at 64. The inflation allowance is intended to adjust certain O&M expenses for inflation where the expenses are heterogeneous in nature and include no single expense large enough to warrant specific focus and effort in adjusting. Boston Edison Company, D.P.U. 1720, at 19-21 (1984). The Department permits utilities to increase their test year residual O&M expense by an independently published price index from the midpoint of the test year to the midpoint of the rate year. D.P.U. 08-35, at 154-155; D.T.E. 02-24/25, at 184; D.P.U. 95-40, at 64; D.P.U. 92-250, at 97-98. 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. 09-30, at 285; D.P.U. 08-35, at 154; D.T.E. 02-24/25, at 184.

In the instant case, NSTAR Gas calculated its inflation allowance from the midpoint of the test year to the midpoint of the rate year, using the GDPIPD as an inflation measure (Exhs. NSTAR-MFF-1, at 39; NSTAR-MFF-5, WP MFF-19 (August 21, 2015)). This calculation method and use of GDPIPD are consistent with Department precedent. D.P.U. 08-35, at 154-155; D.T.E. 02-24/25, at 184; D.P.U. 95-40, at 64; D.P.U. 92-250, at 97-98. Further, we conclude that the Company properly derived its proposed 4.662 percent inflation factor (Exh. NSTAR-MFF-5, WP MFF-19 (August 21, 2015)).

With respect to cost-containment, as discussed in Section VI.B.6.c above, the Company has provided a number of examples of cost-containment measures relative to its health care expenses (Exhs. NSTAR- BPP-1, at 5-8; AG-1-52; DPU-6-10; AG-11-1; AG-11-3, Att.; AG-11-4; AG-11-5; AG-11-8; AG-11-10; AG-11-11; AG-11-19, Atts. (a) at 26-36, (b) at 18-23, (c); AG-11-20). In addition, the Company has demonstrated reasonable measures to control its property and liability insurance expense (Exh. NSTAR-MFF-1, at 29). Based on the above considerations, the Department finds that the Company has implemented cost-containment measures that provide customer benefits sufficient to warrant the allowance of an inflation adjustment. However, we expect that in future base rate proceedings companies will provide specific examples of cost containment measures applicable to the residual O&M expenses that are subject to the inflation allowance.

The Department finds that an inflation allowance adjustment equal to the most recent forecast of GDPIPD for the period proposed by NSTAR Gas, applied to the Company's approved level of residual O&M expense, is appropriate. If an O&M expense has been adjusted or disallowed for ratemaking purposes, such that the adjusted expense is representative of costs to be incurred in the year following new rates, the expense also is removed in its entirety from the inflation allowance. D.P.U. 09-39, at 322; D.T.E. 05-27, at 204; D.T.E. 02-24/25, at 184-185; D.T.E. 01-50, at 19; D.P.U. 88-67 (Phase I) at 141; Commonwealth Gas Company, D.P.U. 87-122, at 82 (1987). The Company has proposed adjustments to the following expense categories and, therefore, removed them from the proposed inflation allowance: (1) advertising expense; (2) uncollectible expense; (3) computer services; (4) dues and memberships; (5) employee benefits; (6) insurance expense; (7) payroll expense; (8) variable compensation; (9) postage; (10) rate case expense; (11) regulatory assessments; (12) leases expense; and (13) HHPP costs (Exh. NSTAR-MFF-5, WP MFF-19 (August 21, 2015)). In addition, the Department has adjusted the Company's expenses associated with shareholder services. Therefore, the test year expense associated with this item, totaling $88,279, will be removed from NSTAR Gas' residual O&M expense calculations, as shown in Table 1.

As shown on Table 1, the inflation allowance for NSTAR Gas is $718,470. The Company proposed an inflation allowance of $722,586. Accordingly, the Department will reduce the Company's proposed cost of service by $4,116.

TABLE 1

Adjusted Test Year O&M Expense per Books	$ 71,335,402
Less Company Adjusted O&M Expenses:	
Advertising	155,291
Uncollectibles	5,638,292
Computer Services	1,790,114
Dues And Memberships	146,097
Employee Benefits	5,157,558
Insurance Expense And Injuries & Damages	2,966,412
Payroll	33,614,160
Variable Compensation	3,144,373
Postage	730,269
Rate Case	-
Regulatory Assessments	698,447
Leases	389,658
Home Heating Protection Plan (HHPP)	1,405,255
Total O&M Adjustments	$ 55,835,926
Subtotal (Adjusted per Books Less Company Adjustments)	$ 15,499,476
Less Excluded Test Year Expenses	
Shareholder Services	88,279
Total	$ 88,279
Residual O&M Expense	$ 15,411,197
Inflation Factor	4.662%
Inflation Allowance	$ 718,470

VII. GAINS ON THE SALE OF PROPERTY

A. Introduction

NSTAR Gas proposes to reduce its revenue requirement to reflect gains on the sale of three parcels of property and the sale of its appliance business. The first property sale occurred on October 1, 2008, when the Company sold land adjacent to its Westwood, Massachusetts office building ("Westwood land sale") for $280,000 (Exhs. NSTAR-MFF-1, at 51; AG-2-32, Att.). NSTAR Gas states that the land was jointly owned with NSTAR Electric Company and that the sale yielded the Company net proceeds of $277,837 (Exhs. NSTAR-MFF-1, at 51; AG-1-20, Att.; AG-2-32, Att.). The Company subtracted from the net proceeds the book value of the property, which was reported as $48,187, to realize a gain of $229,650 (Exhs. NSTAR-MFF-1, at 51; NSTAR-MFF-2, Sch. MFF-23 (August 21, 2015); AG-1-20, Att.; AG-2-32, Att.)

The second property sale occurred on December 27, 2013, when the Company sold land located on LaCombe Street in Marlborough, Massachusetts for $2,500 (Exhs. NSTAR-MFF-1, at 51-52; AG-1-20, Att.; AG-2-32, Att.). NSTAR Gas reported no costs associated with the sale (see Exh. AG-1-20, Att.). The Company subtracted from the proceeds the book value of the land, which was reported as $664, to realize a gain of $1,836 (Exhs. NSTAR-MFF-2, Sch. MFF-23 (August 21, 2015); AG-1-20 & Att.; AG-1-20 (Supp.); AG-2-32, Att.).

The third property sale occurred on March 21, 2014, when the Company sold land located on Quinsigamond Avenue in Worcester, Massachusetts for $1,956,220 (Exhs. AG-1-20 (Supp). & Att.; AG-2-32, Att.). NSTAR Gas reports that total closing costs amounted to $225,497 and, therefore, net proceeds from the sale totaled $1,730,723 (Exhs. AG-1-20, Att. (a)

(Supp.); AG-2-32, Att.). The Company states that this property was classified as non-utility property at the time it was sold in 2014 (Exh. AG-1-20 (Supp.)). However, according to Company records, from 1973 to 1982 portions of the land were transferred from utility plant to non-utility property and, therefore, at one time, these parcels were considered utility property (Exh. AG-1-20, at 1 (Supp.)). The Company reports that net book value of the total property transferred in the 2014 sale was $172,268 (Exh. AG-1-20, at 1 (Supp.)). Further, an adjacent parcel of non-utility property and fencing with a net book value of $12,577, and a parcel of utility property with a net book value of $2,492, were included in the 2014 sale, thus bringing the total net book value of the land transferred on March 21, 2014, to $187,338 (Exh. AG-1-20, at 1-2 (Supp.)).

In an effort to determine the proper ratemaking treatment associated with the sale of the Quinsigamond Avenue property, the Company retained an independent property valuation consultant to conduct an appraisal of the market value of the land[152] (Exh. AG-1-20, at 2 & Att. (b) (Supp.)). The consultant's study estimated the market value of the land in 1982 to be $950,000 (Exh. AG-1-20, at 2 & Att. (b) (Supp.)). The Company proposes to credit to customers the difference between the market value of the property ($950,000) and the net book value at the time of transfer ($187,338), or $762,662 (Exhs. NSTAR-MFF-2, Sch. MFF-23 (August 21, 2015); AG-1-20, at 2 & Att. (a) (Supp.)).

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[152] The transfer of property to an affiliate and the disposition of associated gains or losses is addressed in 220 C.M.R. § 12.00 et seq. Pursuant to these regulations, the transfer of utility property to an affiliate must be accomplished at the higher of net book value or fair market value at the time of transfer. See 220 C.M.R. § 12.04(1); D.T.E. 01-56, at 45. The Department's regulations at 220 C.M.R. § 12.00 et seq. were not in effect in 1982 when portions of the land were transferred from utility to non-utility property (Exh. AG-1-20, at 2 (Supp.)).

Finally, the Company sold its appliance business in May 2008 to an unaffiliated third party[153] (Exhs. NSTAR-MFF-1, at 52; AG-18-19 & Att.). The Company states that the sale yielded net proceeds of $1,750,000 (Exhs. NSTAR-MFF-1, at 52; AG-18-20, Att., at 1). The Company subtracted from the net proceeds the book value of the appliance business assets of $994,410 and transaction costs of $63,568 to realize a gain of $692,021 (Exhs. NSTAR-MFF-1, at 52; NSTAR-MFF-2, Sch. MFF-23 (August 21, 2015); AG-18-20, Att. at 1).

B. Company Proposal

In its original filing, the Company identified the total amount of the gains on the sale of property and the appliance business as $921,671 (Exhs. NSTAR-MFF-1, at 51; NSTAR-MFF-2, Sch. MFF-23). This amount reflected (1) the gain on the Westwood land sale of $229,650; and (2) the gain on the sale of the appliance business of $692,021 (Exh. NSTAR-MFF-2, Sch. MFF-2). The Company made a pro forma adjustment for the sale of the LaCombe Street property in the amount of $2,500 to bring the adjusted amount of the gains total to $924,171 (Exh. NSTAR-MFF-2, Sch. MFF-23). NSTAR Gas proposed to credit this amount to customers over a five-year amortization period, which amounted to an annual revenue requirement reduction of $184,834 (Exhs. NSTAR-MFF-1, at 51; NSTAR-MFF-2, Schs. MFF-6, at 1, MFF-23, MFF-33, at 3).

During the course of the proceedings, the Company updated its original filing to (1) revise the pro forma adjustment with respect to the sale of the LaCombe Street property to $1,836 to account for effect of the property's book value on the gain, and (2) include a pro forma

153 The Company's appliance business leased conversion burners and water heaters to customers (Exh. NSTAR-MFF-1, at 52). The revenues and expenses related to the business were recorded above-the-line and supported by ratepayers (Exh. NSTAR-MFF-1, at 52).

adjustment in the amount of $762,662 to reflect the gain on the sale of the Quinsigamond Avenue property (Exhs. NSTAR-MFF-2, Sch. MFF-23 (August 21, 2015); AG-1-20; AG-1-20 (Supp.) & Atts.). As a result of the updated information, the Company now proposes to credit customers a total of $1,686,169 (Exh. NSTAR-MFF-2, Sch. MFF-23 (August 21, 2015)). The Company proposes to credit this amount to customers over a five-year amortization period, which amounts to an annual revenue requirement reduction of $337,234 (Exh. NSTAR-MFF-2, Schs. MFF-6, at 1, MFF-23, MFF-33, at 3 (August 21, 2015)). Thus, the Company seeks to further reduce its revenue requirement by $152,400 ($337,234 minus $184,834) (Exh. NSTAR-MFF-2, Sch. MFF 33, at 3 (August 21, 2015)).

C. Positions of the Parties

On brief, the Company summarized the aforementioned property sales (Company Brief at 110-111). The Company argues that its proposed adjustment to the revenue requirement properly reflects the disposition of these sales (Company Brief at 111). No other party commented on the Company's proposed adjustment.

D. Analysis and Findings

1. Calculation of the Gains on the Sales of Property

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, if those assets were recorded above-the-line and supported by ratepayers. D.P.U. 07-71, at 65, citing D.P.U. 96-50 (Phase I) at 111; Barnstable Water Company, D.P.U. 93-223-B at 12 (1994); Commonwealth Electric Company, D.P.U. 88-135/151, at 92 (1989). Therefore, if such property is sold by the utility, it is necessary to include an adjustment which recognizes the appreciation on assets that ratepayers have supported in rates through a return of and on investment. D.P.U. 88-135/151, at 92. A gain (or loss) associated with the transfer of utility plant from a company's plant accounts should properly be reflected in rates regardless of the timing of the transfer relative to the test year. D.P.U. 88-135/151, at 92.

The Department has reviewed the record concerning the Westwood land sale, the sale of the LaCombe Street property and the sale of the appliance business, and we find that the Company properly calculated the gains with respect to each transaction (Exhs. NSTAR-MFF-1, at 51-52; NSTAR-MFF-2, Sch. MFF-23 (August 21, 2015); AG-1-20, Att.; AG-1-20 (Supp.); AG-2-32, Att.; AG-18-19; AG-18-20, Att. at 1). With respect to the sale of the Quinsigamond Avenue property, we find the Company's calculation of the gain requires adjustment.

The Company sold the Quinsigamond Avenue property on March 21, 2014, for $1,956,220 (Exhs. AG-1-20 (Supp.) & Atts.; AG-2-32, Att.). The independent property valuation consultant's report makes no mention of an adjacent parcel of non-utility property and fencing, or a parcel of utility property, being sold with the Quinsigamond Avenue property (see Exh. AG-1-20, Att. (b) (Supp.)). In fact, the report refers to only the Quinsigamond Avenue parcel, and includes a copy of the deed that shows only the sale of that one parcel (Exh. AG-1-20, Att. (b) at 3, 5, 8, 20, 31, 40). Therefore, based on the record before us, we find that in determining the gain on the sale of the Quinsigamond Avenue property, it is inappropriate to consider the other parcels for which there is no information regarding their ownership or market value.

The Company reports that net book value of the Quinsigamond Avenue property at the time of the sale in 2014 sale was $172,268 (Exh. AG-1-20, at 1 (Supp.)). We will not consider the book values of the parcel of non-utility property and fencing, or the parcel of utility property, sold with the Quinsigamond Avenue property. Therefore, we find that the difference between the market value of the Quinsigamond Avenue property ($950,000) and the net book value of that property at the time of transfer ($172,268), or $777,732, is the amount of the gain to be credited to customers. This represents a $15,070 increase in the gain from the amount proposed by the Company.

2. Amortization Period

Next, we turn to the appropriate recovery period applicable to the gains. The Company proposes a five-year amortization period (Exhs. NSTAR-MFF-1, at 51; NSTAR-MFF-2, Sch. MFF-23 (August 21, 2015)). In evaluating the appropriate amortization period applicable to a gain on the sale of a utility asset, the Department balances the interests of the utility and ratepayers and has generally found amortization periods in the range of three to six years to be appropriate. See, e.g., D.P.U. 10-55, at 226-227; D.P.U. 08-35, at 139-140; D.P.U. 88-67 (Phase I) at 78-80; Boston Edison Company, D.P.U. 85-266-A/271-A at 33-34 (1986). The Department has considered such factors as the amount under consideration for amortization, the value of the amount to ratepayers based on certain amortization periods, and the impact of the adjustment on the Company's finances and income. D.P.U. 10-55, at 226-227; D.P.U. 93-223-B at 14; D.P.U. 84-145-A at 54. Based on these considerations, we find five years to be an appropriate amortization period.

3. Conclusion

The Company proposed to credit customers a total of $1,686,169 over a five-year amortization period, which amounts to an annual revenue requirement reduction of $337,234

(Exh. NSTAR-MFF-2, Schs. MFF-6, at 1, MFF-23, MFF-33, at 3 (August 21, 2015)). In light of our findings above, we conclude that the total amount of the gains on the sale of the three properties and the appliance business is $1,701,239. A five-year amortization period, applied to the total gain of $1,701,239 produces an annual amortization amount of $340,248. Accordingly, the Department will further reduce the Company's revenue requirement by $3,014.

VIII. SALE OF THE HHPP BUSINESS

A. Introduction

The HHPP is a residential retail services business that the Company has operated for more than 20 years (Exh. NSTAR-WJA-1, at 30). The HHPP business offers enrollees services such as the inspection and repair of customer-owned domestic water and home heating equipment (Exh. NSTAR-WJA-1, at 31). The Company collects payment for its services through a fee-based plan, which offers customers warranty protection for repairs on furnaces, boilers, and water heaters (Exh. NSTAR-WJA-1, at 31). The HHPP business has no assets (Exh. DPU-5-9). As of December 17, 2014, the Company had approximately 28,500 HHPP contracts (Exh. NSTAR-WJA-1, at 31). The HHPP business assets were recorded above-the-line and, therefore, supported by ratepayers (Tr. 1, at 52).

In September 2015, NSTAR Gas sold its HHPP business (Exh. AG-21-8, Att. (Supp. 2) and (Supp. 3)). The Company states that its primary objective in selling the HHPP business was to free up labor resources to meet core distribution business work requirements[154] (Exh. NSTAR-WJA-1, at 32, 35).

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154 The Company states that HHPP work is cyclical and unpredictable and, therefore, the HHPP business did not have its own, dedicated employees (Exh. NSTAR-WJA-1, at 35;

B. Company Proposal

The Company states that the revenues and certain variable costs associated with the HHPP will be eliminated as a result of its sale of the business (Exh. NSTAR-MFF-1, at 64). Therefore, NSTAR Gas removed $6,362,533 in revenues and $2,427,208 in costs[155] from its proposed revenue requirement to account for the sale (Exhs. NSTAR-MFF-1, at 64, 66; NSTAR-MFF-2, Sch. MFF-20 (August 21, 2015); NSTAR-MFF-4, Sch. 1 (August 21, 2015)).

The Company states that, after the sale, the labor resources that were formerly devoted to the HHPP will be used for distribution-related work (Exh. NSTAR-WJA-1, at 36). Therefore, the Company proposes to retain in cost of service $1,890,968 in test year HHPP labor, labor-related, and non-labor costs (Exhs. NSTAR-MFF-1, at 64; DPU-5-10; RR-DPU-1). This amount includes: (1) $635,242 in direct labor costs; (2) $161,744 in employee benefits; (3) $55,075 in payroll taxes; (4) $624,113 in indirect labor costs; (5) $176,142 in fleet costs; and (6) $238,652 in other support area costs, including the customer interactions center, billing, and dispatch (RR-DPU-1, Att.).[156]

Tr. 1, at 22-23). Rather, the Company called upon NSTAR Gas distribution employees to respond to HHPP service calls (Exh. NSTAR-WJA-1, at 35; Tr. 1, at 22-23).

155 After the application of pro forma adjustments to labor-related overtime costs and payroll taxes, the $2,427,208 in costs are comprised of: (1) $940,418 in labor-related overtime costs; (2) $81,534 in associated payroll taxes; (3) $269,911 in advertising expense; (4) $11,644 for invoice costs; (5) $217,631 in merchant fees; and (6) $906,069 in procurement costs (Exhs. NSTAR-MFF-1, at 66; NSTAR-MFF-2, Sch. MFF-20 (August 21, 2015); see RR-DPU-1, Att.).

156 The Company adjusted test year HHPP direct labor costs by a weighted average payroll increase for Local 12004 and Local 369 of 8.991 percent (RR-DPU-1, Att.). Additionally, NSTAR Gas adjusted associated employee benefits by a non-pension and post-retirement benefits other than pension rate of 21.88 percent and payroll taxes of 8.67 percent (RR-DPU-1, Att.). NSTAR Gas adjusted test year fleet costs of $168,296

The Company states that the gain from the sale of the HHPP business is $4,830,001 (Exh. AG-21-8, Att. (b) (Supp. 3)). As such, the Company proposes to credit the gain to customers, and to do so over five years (i.e., $966,000 annually) (Exh. AG-21-8, Att. (b) (Supp. 3)).

C. Positions of the Parties

1. Attorney General

The Attorney General argues that the HHPP is not a regulated public utility service and, as such, its revenues and expenses have been included in utility operations. Therefore, the Attorney General states that HHPP's net operating margin would have been credited against the Company's total utility revenue requirement if the sale did not occur (Attorney General Brief at 13). The Attorney General calculates a net operating margin of $2,230,401 on the HHPP business in 2013, based on revenues of $6,362,533 and expenses of $4,132,132 (Attorney General Brief at 12-13, citing Exhs. NSTAR-MFF-2, Sch. MFF-5 (June 15, 2015); NSTAR-WJA-2, at 1 (May 20, 2015)).

Although she agrees with the Company's calculation of test year HHPP revenues, the Attorney General contends that the Company has not eliminated all HHPP-related expenses from cost of service and, therefore, has understated the net operating margin to be credited to ratepayers (Attorney General Brief at 12, citing Exh. NSTAR-WJA-1, at 1 (May 20, 2015)). Specifically, the Attorney General argues that the Company only removed $2,427,208 in costs that NSTAR Gas categorized as incremental HHPP expenses (e.g., employee overtime, base

by 4.662 percent for inflation (RR-DPU-1, Att.). Finally, the Company increased indirect labor costs and other support areas by a weighted average composite payroll percentage adjustment of 9.161 percent (RR-DPU-1, Att.).

labor allocated to capital, associated payroll taxes, advertising, procurement, merchant fees, and minor miscellaneous invoices) from cost of service (Attorney General Brief at 13, citing Exh. NSTAR-MFF-2, Sch. MFF-20, at 2 (June 15, 2015)). The Attorney General argues that an additional $1,950,845 in HHPP-related direct labor, indirect labor, benefits, payroll taxes, fleet, dispatch, and other expenses (including pro forma adjustments) incorrectly remain in the Company's cost of service (Attorney General Brief at 14, citing Exh. AG-Rebuttal-DJE-1, Sch. DJE-R-2).[157]

The Attorney General disputes the Company's argument that the retention in cost of service of approximately $1.9 million of HHPP expenses is appropriate to account for future distribution-related work following the sale of the HHPP business (Attorney General Brief at 14-15). Regarding the labor and labor-related expenses, the Attorney General argues that the test year hours worked by NSTAR Gas employees on HHPP-related work are not distribution-related expenses and, therefore, should not remain in rates after the sale (Attorney General Brief at 16; Attorney General Reply Brief at 11). The Attorney General contends that the Company failed to provide sufficient evidence that its distribution operations were understaffed during the test year and how it will use these employees to provide distribution-related services going forward (Attorney General Brief at 15). Regarding non-labor

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[157] The Attorney General states that the following $1,791,691 in expenses remain in the Company's cost of service prior to the application of any pro forma rate year adjustments: (1) $582,839 of direct labor; (2) $571,736 of indirect labor; (3) $250,196 of benefits and payroll taxes; (4) $168,296 of fleet expenses; (5) $125,763 of dispatch expense; and (6) $92,861 of other expenses (Exh. AG-DJE-Rebuttal-1, Sch. DJE-R-2). After applying pro forma adjustments, the Attorney General calculates $1,950,845 in HHPP-related costs as remaining in the Company's cost of service (Exh. AG-DJE-Rebuttal-1, Sch. DJE-R-2).

costs (e.g., fleet, dispatch, and call center costs), the Attorney General contends that the Company failed to provide evidence that these costs will continue at the stated levels after the HHPP business is sold and explain why it is appropriate to include these expenses in cost of service after the sale (Attorney General Brief at 15-16).

Based on the above, the Attorney General contends that the Company's proposal to retain approximately $1.9 million in HHPP-related costs in cost of service overstates the Company's test year distribution-related expenses (Attorney General Brief at 16; Attorney General Reply Brief at 12).[158] Accordingly, the Attorney General argues that the Department should eliminate these expenses in their entirety from cost of service (Attorney General Brief at 15-16; Attorney General Reply Brief at 12). The Attorney General asserts that her recommendation to eliminate these expenses is fully consistent with recent Department precedent addressing Bay State Gas Company's sale of its Energy Products and Services ("EP&S") business (Company Brief at 15-16, citing D.P.U. 13-75, at 84-84; Attorney General Reply Brief at 11-12).

The Attorney General does not comment on the Company's calculation of the gain on the sale of the HHPP business or the proposed amortization period of customer credit. The Attorney General contends, however, that even with the amortization of the gain on sale being credited to

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[158] The Attorney General recommends that the Department reduce the Company's cost of service by $1,950,845 in pro forma HHPP business-related expenses (i.e., $1,791,691 test year expenses, plus pro forma rate year adjustments to expenses for labor, benefits, payroll taxes, and other cost categories (Attorney General Brief at 17, citing Exh. AG-Rebuttal-DJE-1, Sch. DJE-R-2; Attorney General Reply Brief at 12).

the cost of service, the net distribution revenue requirement will increase by approximately $3.0 million as a result of the HHPP divestiture[159] (Attorney General Brief at 14).

2. Company

The Company argues that increasing workload obligations together with employee attrition due to an aging workforce has caused natural gas distribution companies to exit non-regulated service businesses that use distribution personnel (Company Brief at 75). NSTAR Gas disputes the Attorney General's contention that the Company has failed to provide evidence that its distribution operations were understaffed in the test year (Company Brief at 88). Likewise, NSTAR Gas argues that it is selling its HHPP business because it needs full access to all gas service technicians employed by the Company to ensure the continued provision of safe and reliable service to its customers (Company Brief at 75-76).

To address its increasing workload obligations, the Company argues that it has increased staffing in its service department (Company Brief at 80, citing Tr. 1, at 24-27). NSTAR Gas claims, however, that these employees' skills and expertise are not generally available in the market (Company Brief at 78, citing Exh. NSTAR WJA 1, at 35). Therefore, NSTAR Gas asserts that it requires 100 percent of its employees' time to meet increasing work requirements on its system (Company Brief at 78).

159 As noted above, the test year net margin on the HHPP business of $2,230,401 was eliminated from the Company's distribution service revenue requirement (Attorney General Brief at 13, 14). Further, the Company proposes to include $1,791,691 of test year HHPP expenses in the cost of service (Attorney General Brief at 14). Thus, according to the Attorney General's analysis, between the loss of the test year HHPP revenue contribution and the Company's proposed inclusion of test year HHPP expenses, customers are approximately $3.0 million worse off as a result of the sale of the HHPP business once the gain is considered (see Attorney General Brief at 14).

NSTAR Gas asserts that, with the sale of the HHPP business, the Company no longer will receive HHPP revenues and some operating costs will be eliminated (Company Brief at 83, citing Exh. NSTAR-MFF-1, at 64). NSTAR Gas contends, however, that because of its increased distribution-related workload, it is vital for the Company to be able to redirect $1,890,968 in test year HHPP-related operating costs to distribution operations going forward (Company Brief at 85, citing DPU-5-10; RR-DPU-1). Accordingly, NSTAR Gas asserts that the HHPP-related costs it proposes to retain in cost of service appropriately represent the level of costs that it will incur going forward after all employees who formerly performed HHPP-related services dedicate 100 percent of their time to distribution-related work requirements (Company Brief at 88).

Further, NSTAR Gas argues that the Attorney General's reliance on D.P.U. 13-75 to justify the exclusion of the HHPP-related operating costs is misplaced and the instant case presents sufficient factual distinctions to support the Company's proposal (Company Brief at 86-87, citing Exh. NSTAR-WJA-1, at 32, 35). Specifically, the Company asserts that the decision to sell Bay State Gas Company's EP&S business was part of a larger transaction by Bay State's corporate parent, while NSTAR Gas' sale of the HHPP business was made for no other reason than to use 100 percent of the labor dedicated to HHPP for "steadily increasing core distribution system workload" (Company Reply Brief at 32).

The Company maintains that test year HHPP-related expenses will remain as an actual cost as the work shifts to distribution-related activities, because the employees in question are already working to meet NSTAR Gas' increasing distribution system workload demands (Company Reply Brief at 31, 34). The Company argues that exclusion of these costs would understate the Company's actual cost of service and accelerate the filing of NSTAR Gas' next rate case (Company Reply Brief at 32). Accordingly, NSTAR Gas argues that the Department should allow it to maintain the HHPP-related costs in rates, as such costs represent the level of expenses it expects to occur in the rate year and beyond (Company Reply Brief at 32).

Finally, NSTAR Gas argues that the final impact of the sale will be known and measurable prior to the Department's final Order in this case (Company Reply Brief at 27). If the Department accepts the Company's proposal to amortize the gain on the sale over five years, NSTAR Gas contends that its sale of the HHPP business will result in an annual credit to customers of the amortized amount of the proceeds (Company Brief at 84, citing Exh. NSTAR-MFF-2, Sch. MFF-22 (June 15, 2015)).

D. Analysis and Findings

1. Introduction

The issues for our determination are: (1) the Company's proposed retention in the cost of service of HHPP labor-related expenses; and (2) the ratemaking treatment of the gain on the sale of the HHPP business. We address each issue below.

2. HHPP Expenses

As noted above, NSTAR Gas sold its HHPP business in September 2015, after the test year in this proceeding (Exh. AG-21-8, at 1 (Supp. 3)). Accordingly, the sale of the HHPP business represents a known and measurable change that requires an adjustment to the Company's cost of service.

The Department finds that the Company has correctly removed $6,362,533 in test year HHPP business revenues from the proposed revenue requirement (Exhs. NSTAR-MFF-1, at 64, 66; NSTAR-MFF-4, Sch. 1 (August 21, 2015)). With respect to HHPP-related expenses, the Company removed $2,427,208 in costs from the proposed revenue requirement but also proposed to retain $1,890,968 in HHPP labor and labor-related costs to account for distribution-related work going forward (Exhs. NSTAR-MFF-1, at 64, 66; NSTAR-MFF-2, Sch. MFF-20 (August 21, 2015); DPU-5-10; RR-DPU-1). The Attorney General challenges the Company's proposal to retain these HHPP expenses in the cost of service (Attorney General Brief at 14-16; Attorney General Reply Brief at 11-12).

The HHPP business was largely a peak period business with the greatest amount of work required in the winter heating season (Tr. 1, at 22). Entering a fall season, the Company typically experienced a high volume of calls from customers participating in the HHPP, with most of these classified as "no heat" calls (Tr. 1, at 22-23). Rather than build a core of HHPP employees whose services effectively would be required only during peak periods to service those calls, the Company used distribution personnel qualified to respond to HHPP service calls (Exh. NSTAR-WJA-1, at 17; Tr. 1, at 22). Thus, during the test year, the Company's distribution service employees performed functions for the HHPP business. These employees are qualified gas-service technicians with expertise and experience not generally available in the marketplace (Exh. NSTAR-WJA-1, at 35).

The Company has provided persuasive evidence that the amount of distribution-related work has increased since the test year due to the high proportion of aging, leak-prone infrastructure (Exhs. NSTAR-WJA-1, at 26; DPU-8-1; DPU-13-10, at 2).[160] As a result of the

[160] In particular, this workload includes leak detection, investigation, and repair; reduction of leak-prone infrastructure backlogs; management of emergent threats; and damage prevention associated with third-party excavations (Exhs. NSTAR-WJA-1, at 26-27;

sale of the HHPP business in September 2015, the distribution service employees who performed functions for the business now will perform full time distribution-related work (Exhs. NSTAR-WJA-1, at 35-36; DPU-8-1). Such work will include external and inside meter repairs and exchanges, back log reduction related to Class III leaks, and service-related corrosion repairs (Exhs. NSTAR-WJA-1, at 36). Accordingly, the Department finds that the Company has demonstrated that there will not be a reduction in labor costs related to the employees who once performed HHPP work, but rather those labor costs continue to be experienced by NSTAR Gas to meet its distribution system workload demands (Exhs. NSTAR-WJA-1, at 36; DPU-8-1; DPU-13-10, at 2). Further, because the HHPP business represented such a small part of the work undertaken in fleet, dispatch, the Company's customer interaction center, and the billing department, it is unlikely that the sale of the business will result in any cost savings in these areas (Exhs. DPU-8-2; DPU-13-10, at 3; Tr. 1, at 55-56). Based on these findings, the Department accepts the Company's proposal to retain $1,890,968 in HHPP labor and labor-related costs in its cost of service to account for distribution-related work going forward.

3. Gain on Sale

As noted above in Section VII, the Department's long-standing policy with respect to gains on the sale of utility property has been to require the pass through to ratepayers of the

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DPU-8-1; DPU-13-10, at 2). Moreover, recent legislative changes require the Company to perform additional leak surveys, repair more leaks, increase communication with municipalities regarding gas leaks, and increase reporting on gas leak repairs (Exh. NSTAR-WJA-1, at 28; Tr. 1, at 16-17). In addition, local and federal regulatory directives require the Company to address issues related to control room management; perform riser and regulator vent heights inspections and atmospheric corrosion inspections; and inspect and repair gate boxes (Exh. NSTAR-WJA-1, at 28-29). Finally, the Company's Distribution Integrity Management Plan has resulted in increased obligations (Exhs. NSTAR-WJA-1, at 28; DPU-8-1; DPU-13-10, at 2).

entire gain associated with the sale if those assets were recorded above the line and supported by ratepayers. D.P.U. 07-71, at 65, citing D.P.U. 96-50 (Phase I) at 111; D.P.U. 93-223-B at 12; D.P.U. 88-135/151, at 92. The Company recorded its HHPP revenues and expenses above the line and, therefore, ratepayers supported the business (Tr. 1, at 52). Accordingly, NSTAR Gas will be required to pass through to ratepayers the entire gain associated with the sale. D.P.U. 07-71, at 65, citing D.P.U. 96-50 (Phase I) at 111; D.P.U. 93-223-B at 12; D.P.U. 88-135/151, at 92.

No parties dispute the Company's calculation of the gain on the sale of the HHPP business or the proposed amortization period of the customer credit. Based on our review, the Department finds that the gain on the sale of HHPP is $4,830,001 and, further, that the Company is required to return this amount to customers (Exh. AG-21-8, Att. (b) (Supp. 3)).

NSTAR Gas proposes a five-year amortization period for the gain on the sale of the HHPP business (Exh. NSTAR-MFF-5, WP MFF-22, at 5 (August 21, 2015)). The Department has considered the amount to be amortized, the value of the amount to ratepayers based on certain amortization periods, and the impact of the adjustment on the Company's finances and income, and finds that a five year amortization period is appropriate. See, e.g., D.P.U. 10-55, at 226-227; D.P.U. 08-35, at 139-140; D.P.U. 88-67 (Phase I) at 78-80; Boston Edison Company, D.P.U. 85-266-A/271-A at 33-34 (1986).

A five-year amortization period, applied to the $4,830,001 gain on the sale of the HHPP business, produces an annual amortization of $966,000 (Exh. AG-21-8, (Supp. 3)). Accordingly, the Department adjusts the Company's cost of service by $52,156.

IX. EXOGENOUS PROPERTY TAX ADJUSTMENT PROPOSAL

A. Introduction

As discussed in Section IV.B.6.c above, as part of the Merger Settlement approved by the Department in D.P.U. 10-170, the Company agreed to freeze its base distribution rates for a period of approximately four years (Merger Settlement at Art. II (3)); see also D.P.U. 10-170-B, at 18, 36. During the term of the rate freeze, the Company agreed to forgo its usual ability to petition the Department for a change in base distribution rates in the event that its costs increase. Nonetheless, the Merger Settlement contains an exogenous cost recovery provision that permits the NSTAR Gas to request recovery of certain unanticipated cost changes beyond its control that would significantly affect the Company's operations (Merger Settlement at Art. II (5)); see also D.P.U. 10-170-B, at 18.

The Merger Settlement approved by the Department in D.P.U. 10-170 authorizes the Company to recover exogenous costs incurred during the term of the rate freeze if certain conditions are met (Merger Settlement at Art. II (5)); see also D.P.U. 10-170-B, at 18. In particular, the Merger Settlement allows the Company to petition for exogenous recovery of incremental property taxes incurred during the rate freeze related to a change in the valuation method for assessing utility property approved by the Massachusetts the Appellate Tax Board ("Appellate Tax Board") [161] (Merger Settlement at Art. II (5)). Pursuant to the Merger Settlement, the incremental costs must meet a minimum annual threshold, based on a percentage

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[161] The Merger Settlement does not describe the manner in which these costs shall be recovered (see Merger Settlement at Art. II (5)).

of the Company's operating revenues, before the Company may even qualify to propose recovery of an exogenous cost[162] (Merger Settlement at Art. II (5)).

In the instant proceeding, NSTAR Gas seeks to recover as an exogenous cost certain incremental property tax expenses related to the adoption of this new valuation method (Exhs. NSTAR-MFF-1, at 71-72; DPU-18-3 & Att.). In addition, although they are not addressed in the exogenous cost mechanism, NSTAR Gas proposes to recover litigation expenses associated with the Company's current and future challenges to any tax assessments based on the new property valuation method (Exhs. NSTAR-MFF-1, at 74; DPU-18-2; DPU-18-3, Att.). For the reasons stated below, we cannot accept the Company's proposal. However, as described below, we will review proposed exogenous cost recovery in a future filing.

B. Background

On December 16, 2009, the Appellate Tax Board issued a ruling approving the City of Boston Board of Assessors' change in valuation method for assessing utility property (see Exh. DPU-18-1, Att. 2-3; see also Boston Gas Company d/b/a KeySpan Energy Delivery New England v. The Board of Assessors of Boston, Docket No. F275055, F275056 (December 16, 2009)). Pursuant to that ruling, the Appellate Tax Board approved Boston's change in method from assessing utility property based on net book value (i.e., original cost less depreciation) to assessing utility property based on weighing net book value equally with

162 For example, the threshold for fiscal year 2012 is $141,771,397 in base distribution revenue x 0.3212 percent = $455,370 (Exh. NSTAR-MFF-4, Sch. 3 (August 21, 2015)).

"reproduction cost new less depreciation"[163] (Exh. DPU-18-1, Att. at 2-3). Boston Gas Company appealed the ruling to the Supreme Judicial Court ("SJC"), which upheld the Appellate Tax Board's decision and determined that the valuation method used by Boston was reasonable. Boston Gas Company v. Board of Assessors, 458 Mass. 715, 729, 739-740 (2011). The SJC then remanded the matter to the Appellate Tax Board for further findings. On April 21, 2011, the Appellate Tax Board issued a final ruling in the matter. Boston Gas Company d/b/a KeySpan Energy Delivery New England v. The Board of Assessors of Boston, Docket No. F275055, F275056 (April 21, 2011).

NSTAR Gas states that the new valuation method approved by the Appellate Tax Board is only applicable to Boston's valuation of Boston Gas Company's facilities (Exh. NSTAR-MFF-1, at 73). According to NSTAR Gas, in the absence of special circumstances, utility property valuations should still be at net book value on a municipality-by-municipality basis (Exh. NSTAR-MFF-1, at 73). NSTAR Gas states, however, that local cities and towns recognize that the change in valuation has the potential to create significant new tax revenues for local municipalities and, therefore, the Company is starting to experience attempts to increase valuations across a number of cities and towns in its service territory (Exh. NSTAR-MFF-1, at 73).

In particular, according to NSTAR Gas, the municipalities of Worcester and Westborough have adopted Boston's new valuation method for assessing utility property and

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163 "Reproduction cost new less depreciation" applies a cost-inflationary factor to age the property in question, with a 20 percent floor on the value of the asset. See Boston Gas Company d/b/a KeySpan Energy Delivery New England v. The Board of Assessors of Boston, Docket No. F275055, F275056, at Appellate Tax Board 2009-1232 (December 16, 2009).

assessed property taxes accordingly for fiscal years 2012, 2013, and 2014[164] (Exhs. NSTAR-MFF1, at 71-72; NSTAR-MFF-4, Sch. 3 (August 21, 2015); DPU-18-2).[165] NSTAR Gas reports that, for that three fiscal years ending in 2014, the Company was assessed $9,325,093 in property taxes by Worcester and $677,952 by Westborough, for a total of $10,003,047 (Exhs. NSTAR-MFF-4, Sch. 3 (August 21, 2015); AG-18-7 & Atts.; RR-DPU-5, Atts. at 1, 9, 17; RR-AG-8, Att.). By contrast, if Worcester and Westborough had assessed the Company's utility property based on net book value for fiscal years 2012, 2013, and 2014, the Company states that the total assessment would have been $6,654,741 (Exhs. NSTAR-MFF-4, Sch. 3 (August 21, 2015); see also Tr. 5, at 397, 399).

NSTAR Gas paid the entire tax amounts assessed by Worcester and Westborough for fiscal year 2012, which amounted to $2,999,899 (Exhs. NSTAR-MFF-4, Sch. 3 (August 21, 2015); AG-18-7 & Atts.; Tr. 5, at 394; Tr. 6, at 532; RR-DPU-5, Atts. at 1; RR-A-8, Att.). For fiscal years 2013 and 2014, NSTAR Gas states that it paid property taxes levied by Worcester and Westborough only up to the point where the Company determined that the taxes reflected the net book value of the assets, and then withheld the remainder of the assessment from payment[166] (see Exh. NSTAR-MFF-4, Sch. 3 (August 21, 2015); AG-18-7 & Att.; Tr. 6,

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164 Minor discrepancies in the amounts presented in each exhibit appear to be due to rounding.

165 NSTAR Gas notes that Boston also assessed the Company's utility property based on the new valuation method but, to date, use of the new method has not resulted in an increase in Boston property tax expense for the Company (Exh. DPU-18-2).

166 NSTAR Gas states that it withheld tax payments in an attempt to elicit a more expeditious response from the municipalities with respect to the Company's tax abatement requests and subsequent appeals, which are discussed below (Tr. 6, at 524; Tr. 14, at 1262).

at 522-523; Tr. 14, at 1262). Specifically, with respect to fiscal year 2013, the property taxes assessed by Worcester and Westborough were $3,579,747, of which the Company paid $2,539,846 and withheld $1,039,901 (Exhs. NSTAR-MFF-4, Sch. 3 (August 21, 2015); AG-18-7 & Atts.; Tr. 14, at 1262, 1264; RR-DPU-5, Atts. at 9; RR-AG-8, Att.). For fiscal year 2014, the property taxes assessed by Worcester and Westborough were $3,423,399, of which the Company paid $2,609,636 and withheld $816,763 (Exhs. NSTAR-MFF-4, Sch. 3 (August 21, 2015); AG-18-7 & Atts.; Tr. 14, at 1262, 1264; RR-DPU-5, Atts. at 17; RR-AG-8, Att.). The unpaid portion of the property taxes assessed by Worcester and Westborough for fiscal years 2013 and 2014 are accruing interest at an annual rate of 14.0 percent (Tr. 6, at 522-523; Tr. 14, at 1263-1264).

In addition to withholding payment for a portion of the fiscal years 2013 and 2014 tax assessments, the Company challenged the new valuation method by filing for tax abatements in both municipalities for fiscal years 2012, 2013, and 2014 (Exhs. NSTAR-MFF-1, at 73; DPU-18-5; DPU-18-6, Att. (a); Tr. 1, at 71; Tr. 14, at 1261; RR-DPU-5, Att. (a) at 5-6, 13-14, 20-21, Att. (b) at 5-6, 13-14, 21-22). Both Worcester and Westborough denied the abatement requests (Exhs. NSTAR-MFF-1, at 73; DPU-18-5 & Atts.; DPU-18-6, Att. (a); Tr. 1, at 71; Tr. 14, at 1261; RR-DPU-5, Att. (a) at 8, 16, 24, Att. (b) at 16, 24). In response, the Company filed appeals with the Appellate Tax Board, which still are pending (Exhs. NSTAR-MFF-1, at 73; DPU-18-5; Tr. 1, at 71; Tr. 14, at 1261-1262; RR-DPU-5 & Atts.). NSTAR Gas states that if the appeals to the Appellate Tax Board are unsuccessful, the Company will appeal further to the Massachusetts Court of Appeals (Exh. NSTAR-MFF-1, at 73).

C. Company's Proposal

NSTAR Gas proposes to treat as an exogenous cost the incremental property tax expense incurred as a result of the adoption of the new utility property valuation method discussed above and to recover these expenses through a new provision in its LDAC tariff called the Exogenous Property Tax Adjustment ("EPTA") (Exhs. NSTAR-MFF-1, at 71-72; DPU-18-3 & Att.). The Company intends for the EPTA to apply to the assessments levied by Worcester and Westborough in fiscal years 2012, 2013, and 2014, and also to any assessments levied by these and any other municipalities that adopt the new valuation method and make it applicable to any tax period up to December 31, 2015 (see DPU-18-2, at 2; DPU-18-3, Att. at 1; Tr. 1, at 65-66). In this regard, the Company proposes in this proceeding to recover $669,661 through the EPTA component of the LDAC, which represents the current incremental tax amount of $3,348,306,[167] amortized over five years (Exhs. NSTAR MFF-2, Sch. MFF-5 (August 21, 2015); NSTAR-MFF-4, Sch. 3 (August 21, 2015); DPU-18-7; DPU 18-8; Tr. 1, at 62-63).

In addition to recovering incremental property tax expenses, the proposed EPTA is designed to recover litigation expenses associated with the Company's current and future challenges to any tax assessments based on the new property valuation method[168]

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167 According to the Company, if Worcester and Westborough had assessed property taxes based on net book value for fiscal years 2012, 2013, and 2014, the total assessments would have amounted to $6,555,077. Pursuant to the new valuation method, the total assessments for those years were $10,003,047 (Exhs. NSTAR-MFF-4, Sch. 3 (August 21, 2015); see also Tr. 5, at 397, 399). Therefore, the Company states that it incurred $3,348,306 in incremental taxes for fiscal years 2012, 2013, and 2014 (Exh. NSTAR-MFF-4, Sch. 3 (August 21, 2015); DPU-18-7).

168 Under the Company's proposal, litigation expenses eligible for recovery through the EPTA would include costs that extend beyond 2015, so long as they relate to legal

(Exhs. NSTAR-MFF-1, at 74; DPU-18-2; DPU-18-3, Att.). The amount of expense recoverable under the proposed EPTA depends upon the Company's success in challenging the property tax assessments and also the municipalities involved.

Specifically, with respect to the Worcester and Westborough tax assessments, if NSTAR Gas is successful in obtaining abatements from Worcester and/or Westborough, the Company proposes to: (1) collect from ratepayers all of the litigation expenses associated with the tax abatement request and appeals process;[169] (2) retain one half of total tax abatement amount; and (3) return the remaining half of the abatement to ratepayers (Exhs. NSTAR-MFF-1, at 74-75; DPU-18-2, at 1; DPU-18-3, Att. at 2; DPU-18-12; Tr. 5, at 424-427, 434-435). If NSTAR Gas is unsuccessful in obtaining tax abatements from Worcester and/or Westborough, the Company proposes to recover from ratepayers: (1) one half of the litigation expenses incurred in pursuing the tax abatements; and (2) the full incremental amount of property tax attributable to the change in the valuation method, including any interest that has accrued on unpaid taxes (Exhs. DPU-18-2, at 1; DPU-18-3, Att. at 2; DPU-18-12; Tr. 5, at 427, 429-430; Tr. 6, at 523-524; Tr. 14, at 1268).

NSTAR Gas proposes a somewhat different treatment for any municipality other than Worcester or Westborough that uses the new valuation method as a basis for assessing the property taxes for tax periods up to December 31, 2015. Under such a scenario, if the Company

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challenges regarding incremental property taxes levied prior to December 31, 2015, using the new property valuation method (Tr. 1, at 64).

169 The Company reports that the total litigation expenses associated with the tax abatement requests and appeals processes for Worcester and Westborough total $78,978 as of May 2015 (Exh. DPU-18-6 & Att. (b) (Supp.1)). Of this amount, $26,068 is included in the Company's test year cost of service (Exh. DPU-18-6 & Att. (b) at 1 (Supp.1); DPU-18-15; RR-DPU-4, at 1; Tr. 1, at 69-70).

is successful in obtaining a tax abatement, it proposes to: (1) collect from ratepayers all of the litigation expenses associated with pursuing the tax abatement; and (2) return to ratepayers the entire tax abatement amount (Exhs. DPU-18-2, at 2; DPU-18-3, Att. at 3; DPU-18-12; DPU-18-13; Tr. 5, at 431-432, 435-436). If the Company is unsuccessful in obtaining a tax abatement, the Company proposes to collect from ratepayers: (1) one half of the litigation expenses incurred in pursuing the abatements; and (2) the full incremental amount of property tax attributable to the change in the valuation method (Exhs. DPU-18-2, at 1; DPU-18-3, Att. at 3; DPU-18-12; Tr. 5, at 436).

D. Positions of the Parties

1. Attorney General

The Attorney General does not take a position with respect to whether or not the Department should approve the Company's proposed exogenous cost recovery or EPTA. If the Department allows the EPTA, the Attorney General argues that the Company should be required to allocate EPTA costs using a distribution plant allocator (Attorney General Brief at 83). The Attorney General notes that, while the Company initially proposed to allocate EPTA costs using a revenue allocator, the Company later revised its proposal to use a distribution plant allocator (Attorney General Brief at 83, citing Exhs. AG-4-9, Att. at 1; Tr. 9 at 817).

2. Company

NSTAR Gas contends that that the Merger Settlement approved by the Department in D.P.U. 10-170 authorizes the Company to recover costs associated with exogenous factors if those costs exceed a threshold in a single calendar year (Company Brief at 172). Further, NSTAR Gas contends that the Merger Settlement specifically allows the Company to seek exogenous recovery of incremental property taxes related to the change in valuation method approved by the Appellate Tax Board (Company Brief at 172, citing Exh. NSTAR-MFF-1, at 71-72). NSTAR Gas argues that it has satisfied all conditions for exogenous cost recovery contained in the Merger Settlement and, therefore, is eligible to recover $3,348,306 in incremental Worcester and Westborough property taxes for fiscal years 2012, 2013, and 2014 (see Company Brief at 173-174, citing Exhs. NSTAR-MFF-4, Sch. 3 (June 15, 2015); DPU-18-7; DPU-18-8; Tr. 1 at 62-63). In addition, NSTAR Gas argues that its proposal to recover incremental property taxes and related litigation expenses through the EPTA component of the LDAC is appropriate because it will allow the Company to recover the costs necessary to support vigorous abatement pursuits (Company Brief at 177, citing Exhs. NSTAR-MFF-1, at 75; Tr. 1, at 73-74). NSTAR Gas asserts that a failure on its part to vigorously pursue the tax abatements could result in tens of millions of dollars in increased property tax bills for the Company and, eventually, its customers (Company Brief at 175, citing Exh. NSTAR-MFF-1, at 73). The Company asserts that if it is successful in challenging the Worcester and Westborough tax assessments, other municipalities will be discouraged from attempting to increase utility property valuations beyond net book value (Company Brief at 175, citing Exh. DPU-18-2; Tr. 14, at 1269). Therefore, the Company argues that its pursuit of tax abatements has significant value to customers and should be encouraged (Company Brief at 175, citing Exh. DPU-18-2; Tr. 14, at 1269).

Further, NSTAR Gas argues that its proposal to recover incremental property taxes and related litigation expenses through the EPTA component of the LDAC is appropriate because customers will receive the benefit of a successful abatement without having to wait for the

Company's next rate case (Company Brief at 177, citing Exhs. NSTAR-MFF-1, at 75; Tr. 1, at 73-74). Finally, the Company asserts that the Department, through its review of the Company's LDAC filings, will retain oversight over the EPTA costs (Company Brief at 177, citing Exhs. NSTAR-MFF-1, at 75; Tr. 1, at 73-74).

E. Analysis and Findings

Pursuant to the Merger Settlement, the Company may seek recovery of incremental property taxes incurred during its rate freeze and associated with the change in valuation method approved by the Appellate Tax Board and affirmed by the SJC through the tax year ending December 31, 2015, provided that the incremental expense qualifies as an exogenous cost and meets the minimum annual threshold (Merger Settlement at Art. II (5)). The Merger Settlement is silent with respect to the method to be used to recover exogenous costs.

The Company proposes to recover incremental property taxes, amortized over five years, through a new EPTA component of the LDAC (Exhs. NSTAR-MFF-1, at 71-72; DPU-18-3 & Att.). In addition, the Company proposes to recover from ratepayers through the EPTA, litigation expenses incurred in pursuing the abatements and interest charged by the municipalities on the unpaid portion of tax assessments (Exhs. DPU-18-2, at 2; DPU-18-3, Att. at 3; DPU-18-12; DPU-18-13; Tr. 5, at 431-432, 435-436, 522-523; Tr. 14, at 1263-1264, 1268). In the event that an abatement request is ultimately successful, the Company proposes to return through the EPTA all or a portion of the total tax abatement to ratepayers, depending on the municipality involved (Exhs. NSTAR-MFF-1, at 74-75; DPU-18-3 & Att.).

Although the Merger Settlement allows the Company to seek recovery of the incremental tax amounts associated with the change in property valuation, the Merger Settlement makes no provision for the recovery of ancillary costs, such as accrued interest or litigation expense. Therefore, interest and litigation costs are not eligible for recovery as exogenous costs under the provisions of the Merger Settlement. The Company, nonetheless, asks the Department to approve its proposed recovery of such costs through an EPTA component of the LDAC. For the reasons discussed below, we do not approve the Company's proposal.

The Company argues that its proposed EPTA will benefit ratepayers because it will allow the Company to recover costs to support abatement activities that are designed to lower the property tax expense ultimately paid by customers (Company Brief at 177). As a public utility, the Company must pursue all reasonable and prudent avenues to protect ratepayer interests, including litigation if warranted. See, e.g., D.P.U. 08-27, at 98; D.P.U. 84-32, at 23; Boston Gas Company, D.P.U. 1100, at 89-92 (1982).

In addition, as discussed below, the Company's cost of service includes $26,068 in test year litigation expenses related to the property tax abatement proceedings (Exh. DPU-18-6, Att. (b) at 1 (Supp.1); DPU-18-15; RR-DPU-4, at 1; Tr. 1, at 69-70). The Company's test year cost of service also includes other amounts related to test year legal expense (RR-DPU-4, at 1). These test year expenses are included in the revenue requirement used to establish rates in this proceeding. Accordingly, we find that dollar-for-dollar recovery of abatement-related litigation expense is not necessary to ensure that the Company appropriately and prudently pursues all avenues to protect ratepayer interests.

Further, with respect to the Company's request to recover interest expense related to the withheld taxes through the EPTA, the Department notes that by withholding payment of a portion of the 2013 and 2014 tax assessments, the Company will have use of this money throughout the duration of the abatement and appeals period. Accordingly, NSTAR Gas has not persuaded the Department that, if the appeals process results in an adverse finding for the Company, ratepayers should be responsible for the interest incurred on the withheld portions. For these reasons, the Department does not approve the Company's proposal to recover abatement-related litigation expense and interest on the withheld property taxes through the EPTA.

With respect to the Company's request to recover incremental property taxes as an exogenous cost through the EPTA component of the LDAC, the Department notes that at the time of the close of the record in this case, the Company's appeals to the Appellate Tax Board of the municipal denials of its tax abatement requests were pending (Exhs. NSTAR-MFF-1, at 73; DPU-18-5; Tr. 1, at 71; Tr. 14, at 1261-1262; RR-DPU-5 & Atts.). If the appeals to the Appellate Tax Board are unsuccessful, the Company states that it will appeal further to the Massachusetts Court of Appeals (Exh. NSTAR-MFF-1, at 73). There is no timeline for resolution of the appeals. Therefore, the Department is unable to now assess whether at the end of the appeals process there will be any incremental taxes and, if there are, whether the amount will be above the annual threshold subject to recovery from ratepayers as exogenous costs.[170] Accordingly, the Department cannot consider the Company's request for recovery of incremental property taxes as an exogenous cost at this time.

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170 As discussed above, based on its calculation of the book value of the utility property in Worcester and Westborough, NSTAR Gas contends that there are $3,348,306 in incremental property taxes for fiscal years 2012, 2013, and 2014 (Company Brief at 173-174, citing Exhs. NSTAR-MFF-4, Sch. 3 (June 15, 2015); DPU-18-7; DPU-18-8; Tr. 1 at 62-63). The Appellate Tax Board or an appellate court could, however, determine that the amount of incremental taxes owed is different than the amount determined by the Company.

Instead, once all appeals are exhausted, the Company should file a separate petition seeking exogenous cost recovery of any incremental property tax assessed using the new valuation method through the year ending December 31, 2015. At that time, the Department and any parties to the proceeding will have an opportunity to investigate the Company's proposal to determine whether the costs satisfy the thresholds and other requirements in the Merger Settlement for exogenous cost recovery and are otherwise recoverable from ratepayers.

Finally, as discussed above, during the test year the Company incurred $26,068 in litigation expenses related to the property tax abatement proceedings (Exh. DPU-18-6, Att. (b) at 1 (Supp.1); DPU-18-15; RR-DPU-4, at 1; Tr. 1, at 69-70). The Department finds that the Company has provided sufficient documentation to support these expenses (Exh. DPU-18-6, Atts. (Supp.)).[171] While we have determined that these litigation expense are not eligible for recovery through the exogenous cost provision of the Merger Settlement or otherwise through the Company's proposed EPTA, the Department finds that these costs are appropriately recoverable as test year outside legal fees (Exh. AG-1-95). See also D.P.U. 88-250, at 66-67. Accordingly, we approve the Company's proposal to retain $26,068 in test year abatement-related legal expense in the Company's cost of service.[172]

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171 We note that portions of the record reflect $36,456 as the amount of test year legal fees related to the property tax abatement proceedings while elsewhere in the record the amount is $26,068 (c.f., Exh. DPU-18-15; AG-1-95; Tr. 1, at 69-70 and Exh. DPU-18-6 & Att. (b) at 1 (Supp.1)). The $26,068 incurred in the test year is the amount of legal costs specifically related to the pursuit of abatements in Worcester and Westborough, while the other exhibits show NSTAR Gas' allocated portion of legal costs concerning other property tax matters, including costs not assignable to one specific city or town (RR-DPU-4).

172 The Company does not seek to recover, outside of the EPTA proposal, of litigation expenses incurred in 2012 of $39,342, nor does it seek any adjustment to cost of service

Based on the findings above, the Department denies the Company's proposal to modify its LDAC tariff for the purpose of establishing an EPTA. In addition, the Department denies the Company's proposal to recover in $669,661 in incremental property tax expense through LDAC (Exhs. NSTAR-MFF-2, Sch. MFF-5 (August 21, 2015); NSTAR-MFF-4, Sch. 3 (August 21, 2015); DPU-18-7; DPU-18-8; Tr. 1, at 62-63). As noted above, once the abatement-related appeals process is complete, the Company should file a separate petition seeking exogenous cost recovery of any incremental property tax assessed using the new valuation method through the year ending December 31, 2015.

X. HOPCO

A. Introduction

HOPCO is a wholly owned subsidiary of Northeast Utilities and owns liquefied natural gas ("LNG") facilities located in the towns of Hopkinton and Acushnet, Massachusetts (together, the "HOPCO facilities") (Exh. NSTAR-WJA-1, at 11). On April 29, 2015, the Department approved a 30-year gas services agreement ("GSA") between NSTAR Gas and HOPCO. NSTAR Gas Company, D.P.U. 14-64, at 75 (2015). The GSA is a full requirements contract that allows NSTAR Gas to purchase LNG services from HOPCO including: (1) storage, vaporization, and liquefaction services from the Hopkinton facility; and (2) storage and vaporization services from the Acushnet facility. D.P.U. 14-64, at 9. Costs approved by the Department for recovery related to HOPCO will be collected through the CGAC (Exh. NSTAR-MFF-1, at 78). The 30-year term of the GSA commences on January 1, 2016, in conjunction with the new rates established this proceeding. D.P.U. 14-64, at 9.

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for the litigation expenses incurred in 2014 of $13,568 (see Exhs. DPU-18-6, Att. B at 1 (Supp.1); AG-1-95, Att.).

The GSA establishes a contract-rate pricing structure to recover costs associated with the operation of the HOPCO facilities as well as planned refurbishments at the facilities. D.P.U. 14-64, at 9. The pricing structure has two rate components, an "Operating Charge" and a "Demand Charge." D.P.U. 14-64, at 10. The Operating Charge is designed to recover variable costs primarily associated with the operation of the Hopkinton facility by Air Products and Chemicals, Inc. ("Air Products"),[173] along with other variable operating costs such as utilities and security expenses. D.P.U. 14-64, at 10. The Operating Charge will change annually, based on the variable costs that it is designed to collect. D.P.U. 14-64, at 10.

The Demand Charge, which will take effect on November 1st of each contract year, is a fixed rate that is designed to recover two categories of costs: (1) O&M costs associated with operating the HOPCO facilities that are not included in the Operating Charge; and (2) the revenue requirement associated with planned capital investments at the HOPCO facilities, including a return on the capital investment, depreciation and amortization, and taxes. D.P.U. 14-64, at 10-11.[174] The Department will establish the initial Demand Charge in the instant proceeding and update the charge periodically. D.P.U. 14-64, at 11-12, 39.[175]

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173 Since commencement of operations in 1971, the Hopkinton facility has been staffed by employees of Air Products, an original joint owner of the facility. D.P.U. 14-64, at 4. Air Products eventually sold its ownership interest in the Hopkinton facility but it has continued to provide O&M and engineering services to the facility under a contract with HOPCO. D.P.U. 14-64, at 4 (see also Tr. 5, at 340, 344, 348).

174 The Demand Charge also will recover administrative and general expenses (e.g., property taxes, and rent and insurance) that currently are recovered through the Company's distribution rates. D.P.U. 14-64, at 10 n.10.

175 More specifically, during the first five years of the GSA, the Demand Charge will be updated annually. D.P.U. 14-64, at 10-11. For the remainder of the contract term, the Demand Charge will be fixed for five-year intervals. D.P.U. 14-64, at 11-12.

B. Company Proposal

The Company developed a proposed cost of service for HOPCO (Exh. NSTAR-EHC-1, at 28). Consistent with the GSA, the proposed cost of service will incorporate the weighted average cost of capital approved in the instant proceeding and serve as the basis for the Demand Charge (Exh. NSTAR-EHC-1, at 28).

The Company's proposed Demand Charge revenue requirement is $7,808,726 (Exh. NSTAR-DPH-7, Sch. DPH-A (August 21, 2015)). The proposed revenue requirement consists of: (1) $1,915,885 in investment return and income tax, based on an investment base of $16,629,471; (2) $2,123,933 in depreciation and amortization expense; (3) $2,397,698 in O&M expense;[176] and (4) $1,371,210 in taxes other than income taxes (Exh. NSTAR-DPH-7, Sch. DPH-1, at 1 (August 21, 2015)).

C. HOPCO Revenue Requirement

1. Rate Base

a. Plant Additions

i. Introduction

NSTAR Gas proposes a rate base for HOPCO of $16,629,471 (Exh. NSTAR-DPH-7, Sch. DPH-1, at 1 (August 21, 2015)). The Company's proposed HOPCO rate base consist of $67,880,407 in total utility plant in service, plus $1,227,140 in accumulated deferred income taxes, plus $471,113 in cash working capital, less $52,949,189 in depreciation and amortization reserve (Exh. NSTAR-DPH-7, Sch. DPH-1, at 1 (August 21, 2015)).

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176 The Company segregates depreciation and amortization expense from O&M expense in the Schedules supporting the HOPCO revenue requirement (see, e.g., Exh. NSTAR-DPH-7, Schs. DPH-A, DPH-1 through 13 (August 21, 2015)).

The proposed HOPCO rate base includes capital additions invested at the facilities from 2000 through 2014, and one project completed in 2015[177] (see Exh. NSTAR-DPH-1, at 2; NSTAR-DPH-7, Schs. DPH-2, at 1, DPH-11 (August 21, 2015)). From January 1, 2000 through the end of the 2013 test year, the Company completed 145 capital projects and invested $17,598,625 in capital additions at the HOPCO facilities (Exhs. NSTAR-LML-1, at 20, 22; NSTAR-LML-6; Tr. 7, at 649). In 2014, the Company completed 27 capital projects and invested $7,871,915 in capital additions at the HOPCO facilities (Exh. NSTAR-LML-6 (Supp.); Tr. 7, at 649). On January 31, 2015, the Company completed a land transfer to HOPCO at a cost of $1,082,206 (Exh. NSTAR-DPH-7, Sch. DPH-11 (August 21, 2015)). Finally, the Company proposes the following additional post-test year adjustments to rate base: (1) $1,685,896 in additional depreciation reserves; (2) $736,131 in additional accumulated deferred income taxes; and (3) $20,663 less in cash working capital (Exh. NSTAR-DPH-7, Sch. DPH-A (excluding 2014) (August 21, 2015)).

ii. Project Documentation

The Company provided various documents in support of the capital additions at the HOPCO facilities (Exhs. NSTAR-LML-1, at 22; NSTAR-LML-1, at 3 (April 15, 2015); NSTAR-LML-6 & Supp.; NSTAR-LML-7, NSTAR-LML-8; NSTAR-LML-9 & Supp.). NSTAS Gas employed substantially the same project authorization and supplemental

[177] NSTAR Gas states that no HOPCO rate base or capital additions were considered as part of the Company's last rate proceeding in D.T.E. 05-85 (Exh. NSTAR-LML-1, at 20). The Company provides HOPCO project data beginning in 2000 in the instant proceeding (Exh. NSTAR-LML-1, at 20).

authorization policies for the HOPCO capital additions as it did for the Company's capital addition projects (Exh. AG-22-17; Tr. 7, at 606, 607-608).[178]

With respect to the Hopkinton facility, the Company states that Air Products develops the annual capital and operating budgets and provides its own project authorizations for certain projects (Exh. NSTAR-LML-1, at 20; Tr. 7, at 606). The Company notes, however, that NSTAR Gas decides whether a project ultimately will be authorized and approves the budget for authorized projects (Exh. NSTAR-LML-1, at 20-21).

As discussed above in Section IV.B.5.a, the Attorney General provides specific recommendations regarding the appropriateness of the Company's project documentation and proposed rate base additions (Attorney General Brief at 10-11). With respect to the 145 HOPCO-related capital projects completed from 2000 through 2013, the Attorney General identifies 66 projects as purportedly lacking one or more of the following: (1) sufficient documentation to support initial cost estimates; (2) specific reasons for cost variances in instances where actual costs varied by 30 percent or more from original cost estimates; and (3) in instances where actual costs varied by 30 percent or more from original cost estimates, an allocation of the total variance amount to the specific reasons for the variance (Attorney General Brief at 10-11, citing Exh. DPU-AG-2-1, Att.).[179] The Department addresses these projects below.

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[178] The Company's authorization policies are described in further detail Section IV.B.2 above.

[179] As explained further in Section IV.B.5.a.iii above, the Attorney General provided a list of capital projects that she contends, for various reasons, should not be included, in whole or in part, in rate base. The Attorney General identifies 21 HOPCO-related Type A projects (i.e., HOPCO projects that lack documents to support project cost estimates) and

iii. Positions of the Parties

(A) Attorney General

The Attorney General argues that for 21 HOPCO-related capital projects completed between 2000 and 2013, the Company failed to provide either the estimated cost of the project or documentation to support the estimated costs (Attorney General Brief at 11, citing Exh. DPU-AG-2-1, Att.). Accordingly, the Attorney General argues that the Department should not allow the Company to recover the costs for these projects because they lack proper documentation (Attorney General Brief at 11, citing D.P.U. 09-30, at 114).

Further, the Attorney General contends that for each of these 21 of these projects, and for an additional 45 projects completed between 2000 and 2013, actual costs varied by 30 percent or more from original cost estimates (Attorney General Brief at 11, citing Exh. DPU-AG-2-1, Att.). The Attorney General argues that, in most cases, the Company did not provide any reasons for the variance (Attorney General Brief at 11). In the cases where the Company did provide reasons for the variance, the Attorney General asserts that NSTAR Gas failed to allocate the total variance amount to the specific reasons for the variance provided (Attorney General Brief at 11). Because the Company has not provided the Department with sufficient evidence to determine whether the variances were prudent, the Attorney General argues that the Department should deny recovery of any cost overruns for these projects (Attorney General Brief at 11, citing D.P.U. 12-25, at 83).

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66 HOPCO-related Type D projects (i.e., HOPCO projects that lack all or sufficient supporting documentation for cost variances (positive and negative) greater than 30 percent) that were completed between January 1, 2000 and December 31, 2013. Because certain projects are alleged by the Attorney General to suffer from multiple failures of proof, the 21 HOPCO-related Type A projects are also included in the identification of the 66 HOPCO-related Type D projects (see Exh. DPU-AG-2-1, Att.).

Finally, the Attorney General argues that the Department should deny any adjustments to rate base for post-test year capital additions undertaken at the HOPCO facilities (Attorney General Brief at 7-8). The Attorney General contends that the Company failed to justify a departure from Department precedent that precludes post-test year additions to rate base (Attorney General Brief at 8-9, citing D.P.U. 13-75, at 106-107).[180]

(B) Company

The Company's general arguments supporting its capital additions, including post-test year additions, are set forth in Section IV.B.5.b above. With respect to the HOPCO capital projects identified by the Attorney General, the Company argues that it has provided all necessary project documentation and explanation for cost overruns and, therefore, the Department should include these projects in their entirety in HOPCO's rate base (Company Brief at 62).

Regarding the alleged lack of documentation supporting cost estimates for certain HOPCO projects, the Company argues that pre-construction estimates were not required for these projects because they are smaller projects (i.e., projects with estimated costs under $100,000) and completed under blanket authorizations (Company Brief at 60-61, citing Tr. 7, at 598, 627, 635, 652). NSTAR Gas asserts that, instead, it documented the total actual cost of each project and employed an adequate process to contain project costs (Company Brief at 61, citing Tr. 7, at 652-654). For the Hopkinton facility, the Company argues that the projects were

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[180] As noted below, the Attorney General specifically addresses three capital projects completed in 2014 that she claims lack proper project documentation.

completed subject to a process where Air Products (i.e., the operator of the facility) is responsible for estimating and managing project costs[181] (Company Brief at 61-62).

Further, with respect to these capital additions and numerous other HOPCO capital additions with a variance of 30 percent or more, the Company contends that the Attorney General's arguments regarding lack of documentation or sufficient explanation for the variances are misplaced (Company Brief at 69-70). First, the Company notes that all but six of the projects identified by the Attorney General have costs under $100,000 and, therefore, were completed using blanket authorizations (Company Brief at 70). The Company contends that, because they are relatively small in size, these projects do not require pre-construction project authorizations or variance analyses on an individual project basis (Company Brief at 70, citing Tr. 7, at 598, 627, 635, 652). For these projects, the Company asserts that it documented the total actual cost of each project and employed a successful cost containment process (Company Brief at 90, citing Tr. 7, at 652-654). Further, the Company reiterates that for the Hopkinton facility projects questioned by the Attorney General, the operator of the facility is charged with managing the projects and estimating costs[182] (Company Brief at 70).

For the remaining six projects, the Company contends that the Attorney General identified only three as having no variance analysis, and each of these three had a negative

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181 According to NSTAR Gas, Air Products typically provides a "vendor quote" to the Company, which the Company then authorizes (Company Brief at 61). The Company asserts that Air Products is required to work to the authorized quote unless it is able to document the need to change the authorized price (Company Brief at 61).

182 With respect to the Acushnet projects, the Company asserts that these are managed by NSTAR Gas as gas supply projects, which are completed pursuant to blanket authorizations (Company Brief at 70).

variance (i.e., the three projects were under budget)[183] (Company Brief at 70). Based on the above, the Company argues that it provided all necessary project documentation relative to the HOPCO plant additions (Company Brief at 70-71, 202, citing Exhs. NSTAR-LML-8; NSTAR-LML-9 & Supp.). Further, the Company asserts that its rigorous project authorization policy, including its policy in relation to Air Products' operation of the Hopkinton facility, ensures that appropriate steps are taken to supervise cost changes and control projects costs (Company Brief at 202-203). Therefore, the Company argues that the HOPCO capital additions meet the Department's standards for inclusion in rate base (Company Brief at 202-203).

iv. Analysis and Findings

(A) Test Year-End Plant Additions

Between January 1, 2000 and December 31, 2013, the Company completed construction on 145 capital addition projects at the HOPCO facility (Exh. NSTAR-LML-1, at 22). The Company provided various documentation for each capital project, including information regarding estimated costs, total costs, variances, and in service dates (Exhs. NSTAR-LML-7; NSTAR-LML-8; NSTAR-LML-9). The Attorney General challenges 21 of these projects based on the adequacy of the documents provided by the Company to support cost estimates (Attorney General Brief at 11). For these 21 projects, and for another 45 projects (i.e., a total of 66 projects), the Attorney General contends that the Company did not properly document project cost variances (Attorney General Brief at 11). Further, she argues that NSTAR Gas failed to allocate the total variance amount to the specific reasons for the variance provided (Attorney General Brief at 11).

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183 The Company did not address the remaining three projects on brief.

Regarding the 21 HOPCO-related capital projects that the Attorney General identifies as either lacking the estimated cost of the project or documentation to support the estimated costs, for each project, the Company provided a capital authorization analysis that includes the estimated cost of the project, the total cost of the project, and the amount of the variance (if any) (see Exhs. NSTAR-LML-8; NSTAR-LML-9; DPU-AG-2-1, Att.). The Department has reviewed the documentation and finds that NSTAR Gas provided project documentation with cost estimates for these projects and that such documentation is sufficient in this case to support a prudence analysis.

With respect to these projects and the remaining contested projects from 2000 through 2013 that had a cost variance of 30 percent or more, all but ten of these projects (i.e., 56 projects) had estimated or actual direct costs $100,000 or under and were completed under blanket authorizations (see Exhs. NSTAR-LML-8; NSTAR-LML-9; DPU-AG-2-1, Att. Tr. 7, at 627).

Pursuant to the Company's current capital project authorization policy, projects that qualify to use blanket authorizations do not require the preparation of specific pre-construction project authorizations or variance analyses on an individual project basis (Exhs. DPU-13-13 & Atts.; DPU-13-14; DPU-13-15; Tr. 7, at 598, 627, 635, 652). As a measure of cost control, however, the Company reviews these capital projects on at least a monthly basis, during which senior management reviews the scope, size, design and status of each approved project to determine if any changes require adjusted cost estimates (Exh. NSTAR-LML-1, at 18). Further, although Air Products develops the annual capital and operating budget for the Hopkinton facility, NSTAR Gas ultimately authorizes a project to move forward and approves the budget for each project (Exh. NSTAR-LML-1, at 20-21). If circumstances arise to cause the actual cost of a project to deviate from the budgeted cost, Air Products works with NSTAR Gas to obtain a continued authorization for the project (Exh. NSTAR-LML-1, at 21). The Company reviews larger change orders at the Hopkinton facility through its supplemental authorization process as a way to monitor and control costs (Exh. NSTAR-LML-1, at 20).

As discussed in Section IV.B.6.e.i above, the Department has concerns about the Company's use of blanket authorizations and variance analyses and these concerns apply equally to HOPCO-related capital projects. In particular, the Department found that the Company's threshold for blanket authorizations is at a level that impairs our ability to conduct an efficient and thorough prudence review.

In the instant case, in consideration of the policies that the Company has in place to monitor and control costs, the Department will review the capital project documentation and closing reports for all work orders completed under blanket authorizations to determine whether the expenditures were prudently incurred. As discussed in detail in Section IV.B.6.e.i above, going forward, NSTAR Gas shall document all cost variances and provide variance analyses on all projects (completed under blanket authorizations or not) with actual direct costs in excess of $50,000.

Pursuant to the Company's current project authorization policy, 56 of the projects did not require a supplemental explanation or authorization for the variances (see Exhs. NSTAR-LML-8, 2013 99931 WO 1943609; 2004 99931 WO 1400152; 2000 99931 WO 430257). However, the Company provided estimated costs, actual costs, and closing reports for each project (see, e.g., Exhs. NSTAR-LML-9, 2013 99931 WO 1943609; 2004 99931 WO 1400152; 2000 99931 WO 430257). The Department has reviewed these documents and finds that NSTAR Gas has provided sufficient explanation for cost variances and, in these instances, a further breakdown of the costs is not required in order for the Department to assess prudence.

Together with the process the Company has in place to monitor and control costs, the Department finds that the costs of the 56 capital projects, including the project variances, were prudently incurred (see Exhs. NSTAR-LML-8, 2013 99931 WO 1943609; 2004 99931 WO 1400152; 2000 99931 WO 430257). Further, we find that the Company has demonstrated that each project is used and useful in service to customers (Exh. NSTAR-LML-7). Accordingly, the Department will include the costs of these 56 projects in rate base.

With respect to the ten capital projects specifically identified by the Attorney General that had estimated or actual direct costs in excess of $100,000 and a final cost variance of 30 percent or more, the Company provided a capital authorization analysis for each project (Exhs. NSTAR-LML-8; NSTAR-LML-9, 2000 99938 WO 430255; 2002 99933 WO 430229; 2002 99934 WO 430235; 2003 1980 WO 432143; 2003 3900 WO 1345326; 2004, 4900 WO 1345324; 2005 5900 WO 1450779; 2007, 7900 WO 1530766; 2008 99931 WO 1656382; 2013, 13900 WO 1922342; DPU-AG-2-1, Att.). Seven of the projects had a negative cost variance and, therefore, the Department need not address the prudence of such variances (Exh. NSTAR-LML-9, 2000 99938 WO 430255; 2002 99933 WO 430229; 2002 99934 WO 430235; 2003 1980 WO 432143; 2003 3900 WO 1345326; 2005 5900 WO 1450779; 2008 99931 WO 1656382; DPU-AG-2-1, Att.). For the remaining three projects, the Company provided a P&N document that contains an explanation of the cost overrun (Exh. NSTAR-LML-9, 2004, 4900 WO 1345324; 2007, 7900 WO 1530766; 2013, 13900 WO 1922342).

The Department has reviewed all documentation provided by the Company with respect to the ten projects, including capital authorization analyses, P&N documents (if applicable), work order summaries (i.e., closing reports), and in-service dates (Exhs. NSTAR-LML-7; NSTAR-LML-8; NSTAR-LML-9, 2000 99938 WO 430255; 2002 99933 WO 430229; 2002 99934 WO 430235; 2003 1980 WO 432143; 2003 3900 WO 1345326; 2004 4900 WO 1345324; 2005 5900 WO 1450779; 2007 7900 WO 1530766; 2008 99931 WO 1656382; 2013 13900 WO 1922342). Based on our review, the Department finds that NSTAR Gas has provided sufficient explanation for cost variances and, in these instances, a further breakdown of the costs is not required in order for the Department to assess prudence.

Together with the process the Company has in place to monitor and control costs, the Department finds that the costs of the ten capital projects, including the project variances, were prudently incurred (see Exhs. NSTAR-LML-8; NSTAR-LML-9, 2000 99938 WO 430255; 2002 99933 WO 430229; 2002 99934 WO 430235; 2003 1980 WO 432143; 2003 3900 WO 1345326;2004 4900 WO 1345324; 2005 5900 WO 1450779; 2007 7900 WO 1530766; 2008 99931 WO 1656382; 2013 13900 WO 1922342). Further, we find that the Company has demonstrated that each project is used and useful in service to customers (Exh. NSTAR-LML-7). Accordingly, the Department will include the costs of these ten projects in rate base.

Finally, the Department has reviewed the project documentation associated with the remaining 79 HOPCO-related capital projects (i.e., 145 total projects less 66 projects described above) completed between January 1, 2000 and December 31, 2013, but not specifically addressed or challenged by the Attorney General. In particular, the Company has provided capital authorization analyses for these projects and, depending upon the size of the project, P&N

documents and work order summaries (see Exhs. NSTAR-8; NSTAR-LML-9). The Company also has provided in-service date documentation for these projects (Exh. NSTAR-LML-7). Together with the process the Company has in place to monitor and control costs, the Department finds that the Company has supported the prudence of the proposed projects and variances. Based on our review, Department finds that the project costs were prudently incurred and the projects are used and useful in service to customers.

Based on all of the above considerations, the Department approves $59,356,984 in HOPCO plant in service, which represents the capital additions made to the HOPCO facilities from 2000 through 2013 (Exh. NSTAR-DPH-7, Sch. DPH-A (excluding 2014) (August 21, 2015)).

(B) Post-Test Year Plant Additions

As noted above, in 2014, the Company completed 25 capital projects and two land transfers and invested $7,871,915 in capital additions at the HOPCO facilities (Exhs. NSTAR-LML-6 (Supp.); NSTAR-LML-9 (Supp.); DPU-19-10, Att. (d); Tr. 7, at 649). Of the 25 projects, 17 were completed at or under budget and eight were over budget (Exhs. NSTAR-LML-9 (Supp.); DPU-19-10, Att. (d)). Further, on January 31, 2015, the Company completed a land transfer to HOPCO at a cost of $1,082,206 (Exh. NSTAR-DPH-7, Sch. DPH-11 (August 21, 2015)). Consistent with the findings made in Section IV.B.6.c above, the Department will review the post-test year plant additions to determine if they qualify for inclusion in rate base under the prudent, used and useful standard.

Of the 17 projects that were completed at or under budget, one project was challenged by the Attorney General and is discussed in below. Accordingly, 16 unchallenged projects were completed at or under budget. Of these unchallenged projects, the Department has examined the documentation provided by the Company for the projects that are at or under budget, including work orders, capital authorization analyses, in-service date documentation, and closing reports (Exhs. NSTAR-LML-6 (Supp.); NSTAR-LML-9 (Supp.)). The Department finds that the level of documentation provided for these projects adequately supports the proposed projects. Based on our review, the Department finds that the costs for these 16 unchallenged projects were prudently incurred and that the capital investments are used and useful in service for customers. Accordingly, the Department will include the cost of these 16 projects in plant in service.

Of the eight projects that were completed over budget, only two were challenged by the Attorney General. The remaining six projects were completed over budget, but each project cost under $100,000 (Exhs. NSTAR-LML-9 (Supp.) 2014, 99931, WOs 1933824; 1933821; 1933825; 1943610; 1963275; 1983469; DPU-19-10, Att. (d)). Of these unchallenged projects, the Department has examined the documentation provided by the Company for the projects that were completed over budget, including work orders, vendor estimates, in-service date documentation, and closing reports (Exhs. NSTAR-LML-6 (Supp.); NSTAR-LML-9 (Supp.) 2014, 99931, WOs 1933824; 1933821; 1933825; 1943610; 1963275; 1983469). The Department finds that the level of documentation provided by the Company adequately supports our ability to review the prudence of the proposed projects. The Department finds that the costs for these six projects were prudently incurred and that the capital investments are used and useful in service for customers. Accordingly, the Department will include the cost of these six uncontested projects in rate base.

In addition, the Company provided documentation regarding the two land transfers that were completed in 2014 (Exhs. NSTAR-LML-6 (Supp.); NSTAR-LML-9 (Supp.) 2014, 14887 WOs 02002970; 02002969; DPU-19-10, Att. (a)). The Department has examined the documentation and other evidence provided by the Company for these transfers (Exhs. NSTAR-LML-6 (Supp.); NSTAR-LML-9 (Supp.) 2014, 14887 WOs 02002970; 02002969; DPU-19-10, Att. (a); Tr. 7, at 609). The Department finds that the land transactions were prudently incurred and the land is used and useful to ratepayers.[184]

As noted above, three of the 27 projects completed in 2014 were challenged by the Attorney General.[185] All three projects had costs under $100,000 and a final cost variance of 30 percent or more (Exhs. NSTAR-LML-9 (Supp.) 2014, 99931 WOs 1870275; 1933822; 1933828; DPU-AG-2-1, Att.; DPU-19-10, Att. (d)). One project had a negative cost variance and, therefore, the Department need not address the prudence of this variance (see Exh. NSTAR-LML-9 (Supp.) 2014 99931WO 1870275). The Department has reviewed the information provided by the Company for this project and finds that its costs were prudently incurred and the project is used and useful in service to customers (see Exhs. NSTAR-LML-6 (Supp.); NSTAR-LML-9 (Supp.) 2014 99931 WO 1870275; DPU-19-10, Att. (d)). Accordingly, the Department will include the costs of this project in rate base.

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184 In D.P.U. 14-64, at 33, the Department found that the HOPCO facilities are an important and necessary component of the Company's resource portfolio. The evidence here indicates that the land acquired was necessary for the safe and efficient operation of the HOPCO facilities (Tr. 5, at 609; Tr. 7, at 359).

185 The Attorney General challenges: (1) one of the 17 projects that were completed at or under budget; and (2) two of the eight projects that were completed over budget.

Regarding the two remaining projects, the Company's current project authorization policy did not require a supplemental explanation or authorization for the variances because the project costs were under $100,000 (see Exh. NSTAR-LML-1, at 17-18). However, the Company provided estimated costs, actual costs, and closing reports for each project (see Exh. NSTAR-LML-9 (Supp.) 2014 99931 WOs 1933822; 1933828). The Department finds that NSTAR Gas has provided sufficient explanation for cost variances and, in these instances, a further breakdown of the costs is not required in order for the Department to assess prudence. Together with the process the Company has in place to monitor and control costs, the Department finds that the costs of the two capital projects, including the project variances, were prudently incurred and the projects are used and useful in service to customers (see Exhs. NSTAR-LML-6 (Supp.); NSTAR-LML-9 (Supp.) 2014 99931 WOs 1933822; 1933828; DPU-19-10, Att. (a)). Accordingly, the Department will include the cost of these two projects in plant in service.

Finally, with respect to the one plant addition occurring in 2015, the Company provided documentation regarding the land transfer from the Company to HOPCO that was completed in January 2015 (Exh. AG-22-3, Att. (a) at 1). The Department has examined the documentation provided by the Company for this project (Exh. AG-22-3, Atts.). The Department finds that the land transaction was prudently incurred and the land is used and useful to ratepayers. Accordingly, the Department will include the cost of this project in plant in service.

Based on all of the above considerations, the Department approves $67,880,407 in HOPCO plant in service, which represents the post-test year capital additions made to the HOPCO facilities addressed above (Exh. NSTAR-DPH-7, Sch. DPH-A (August 21, 2015).

b. Post-Test Year Adjustments

The Company proposes to implement the following post-test year adjustments related to HOPCO's rate base: (1) $1,685,896 in additional depreciation reserves; (2) $736,131 in additional accumulated deferred income taxes; and (3) $20,663 less in cash working capital (Exh. NSTAR-DPH-7, Sch. DPH-A (excluding 2014) (August 21, 2015)). Consistent with our findings above, the Department allows these post-test year adjustments to rate base. In addition, the Department directs the Company to include an additional $30,011 ($176,575 less $146,564) in cash working capital related to pension and PBOP expenses for HOPCO employees (see Exh. NSTAR-DPH-7, Sch. DPH-1, at 3 (August 21, 2015); RR-DPU-11, Att. (b), at 3)

2. Expenses and Taxes

In addition to plant, the proposed HOPCO revenue requirement includes: (1) $2,123,933 in depreciation and amortization expense; (2) $2,397,698 in O&M expense; and (3) $1,371,210 in taxes other than income taxes (Exh. NSTAR-DPH-7, Sch. DPH-1, at 1 (August 21, 2015)). The Department has reviewed the evidence supporting the Company's calculation of these components of the revenue requirement (Exhs. NSTAR-EHC-1, at 27-32; NSTAR-EHC-7, Schs. EHC-1 through EHC-13; NSTAR-EHC-7 WP EHC-3 through WP EHC-10; NSTAR-DPH-1 (April 15, 2015); NSTAR-DPH-7, Schs. DPH-A, DPH-1 through 13 (August 21, 2015); NSTAR-DPH-7 WP DPH-3 through WP DPH-10; AG-1-26, Att.; AG-22-3; Tr. 5, at 357-359) The Department finds that Company's calculations are correct, with one exception.

Consistent with our finding in Section XI.A.2 below, the Department directs the Company to include in the HOPCO revenue requirement employee pension and PBOP expenses for HOPCO employees. The amount of expense to be included in the revenue requirement is $240,085 ($347,764 less $107,679) (see Exh. NSTAR-DPH-7, Sch. DPH-2, at 2 (August 21, 2015); RR-DPU-11, Att. (b), at 7).

D. Conclusion

Based on the findings above, the Department approves a total rate base of $16,659,482 for HOPCO comprised of: (1) a total gross plant of $67,880,407; (2) accumulated deferred income taxes of $1,227,140; (3) a cash working capital amount of $501,124; and (4) a depreciation and amortization reserve of $52,949,189. Further, the Department approves for HOPCO: (1) depreciation and amortization expense of $2,123,933; (2) O&M expense of $2,637,783 ($2,397,698 plus $240,085); and (3) taxes other than income taxes expense of $1,371,210.

Pursuant to our decision in D.P.U. 14-64, at 69-70, the same capital structure and return on equity approved for NSTAR Gas in this proceeding applies to the HOPCO operations. As part of its compliance filing in this proceeding, the Company shall recalculate a Demand Charge revenue requirement consistent with the findings above and in Section XII.E.9 of this Order.[186]

XI. GAS ACQUISITION ISSUES

A. Gas Acquisition Costs

1. Introduction

The Company proposes to collect through its CGAC a fixed amount of gas acquisition costs in the amount of $1,108,479 (Exhs. NSTAR-MFF-1, at 76; NSTAR-MFF-4, Sch. 4

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[186] As part of this calculation, the Company is directed to provide an updated version of Exhibit NSTAR-DPH-7.

(August 21, 2015)).[187] This amount is comprised of: (1) test year gas acquisition costs of $903,051, which the Company removed from its distribution revenue requirement; and (2) a post-test year adjustment of $296,118 (Exhs. NSTAR-MFF-1, at 76; NSTAR-MFF-2, Sch. MFF-6, at 2 (August 21, 2015); NSTAR-MFF-4, Sch. 4 (August 21, 2015)). The Company's proposed post-test year adjustment accounts for changes in labor, payroll taxes, employee benefits, and integrated resource planning costs related to gas acquisition activities (Exhs. NSTAR-MFF-1, at 76-77; NSTAR-MFF-4, Sch. 4 (August 21, 2015)).

Currently, NSTAR Gas collects pension and PBOP costs associated with gas acquisition personnel through its pension adjustment mechanism (Exhs. NSTAR-MFF-1, at 76-77; DPU-8-4). The Company proposes to continue this ratemaking treatment of these costs. The Company states that continued recovery of pension and PBOP-related costs through the pension adjustment mechanism will simplify and facilitate review for all parties and is consistent with the settlement approved in NSTAR Electric Company/NSTAR Gas Company, D.P.U. 14-151 (2015) (Exh. DPU-8-4).[188] Alternatively, the Company states that gas acquisition-related pension and PBOP costs could follow the related labor costs and be recovered in the various reconciling mechanisms that recover labor costs. The Company states that this approach would require adjustments to the pension adjustment mechanism and CGAC (Exh. DPU-8-4; RR-DPU-11).

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187 Currently, NSTAR Gas collects $717,123 in gas acquisition costs through the CGAC in accordance with the settlement approved in Boston Edison Company, D.P.U./D.T.E. 96-23 (1998) (Exh. NSTAR-MFF-1, at 76).

188 In D.P.U. 14-151, the Department approved a settlement where, among other things, the Company agreed to refund to customers energy efficiency-related pension and PBOP costs that were inappropriately collected through the pension adjustment mechanism. D.P.U. 14-151, at 7-8.

Further, NSTAR Gas states that if the Department approves this alternate approach, it also would need to amend its GSA with HOPCO to specifically reflect the collection of HOPCO-related pension and PBOP costs through the gas services agreement (RR-DPU-11, at 2). No party commented on the Company's proposals.

2. Analysis and Findings

The Department has previously approved the use of allocated cost of service studies that allocate gas acquisition employee costs to the CGAC. D.T.E. 05-27, at 307-308; D.T.E. 03-40, at 368-369. The Department also has approved the collection of gas acquisition costs through the CGAC. D.T.E. 02-24/25, at 283-284; D.P.U 93-60, at 268-281; See also Commonwealth Gas Company, D.T.E. 98-63 (1998). The Company's proposal to collect gas acquisition costs through the CGAC is consistent with Department precedent. Accordingly, we approve the Company's proposal.

Regarding the Company's proposed adjustment of $296,118 to test year labor, payroll taxes, employee benefits, and integrated resource planning costs, the Department finds that they are known and measurable and reasonable in amount (Exhs. NSTAR-MFF-1, at 76; NSTAR-MFF-2, Sch. MFF-6, at 2 (August 21, 2015); NSTAR-MFF-4, Sch. 4 (August 21, 2015)). Accordingly, the Department allows the proposed adjustment.

Finally, the Company proposes to continue to collect through the pension adjustment mechanism pension and PBOP costs associated with gas acquisition personnel (Exhs. NSTAR-MFF-1, at 76-77; DPU-8-4). The Department has found that supply-related gas costs should be collected through the CGAC. Commonwealth Gas Company, D.T.E. 98-63 (1998); D.P.U 93-60, at 281; D.T.E. 02-24/25, at 284. The salaries and benefits of the

Company's gas acquisition personnel are clearly supply-related gas costs. D.P.U. 93-60, at 281. Therefore, we find that these costs should be recovered through the CGAC and not through the pension adjustment mechanism.[189]

NSTAR Gas reports that its test year pension and PBOP costs associated with the Company's gas acquisition activities were $128,975 (RR-DPU-11 (a) at 4). Accordingly, the Department approves gas acquisition costs of $1,237,454 ($1,108,479 in fixed costs plus $128,975 in pension and PBOP costs) for collection through the CGAC. The Company shall adjust the pension adjustment factor within the pension adjustment mechanism to reflect the removal of pension and PBOP costs associated with gas acquisition activities. Further, the Company shall revise the relevant sections of its gas services agreement with HOPCO to reflect the collection of the HOPCO-related pension and PBOP costs through the gas services agreement. The Company shall provide an amended GSA as part of its compliance filing in this case.

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[189] The Company's reliance on our decision in D.P.U. 14-151 to support the collection of is gas acquisition-related pension and PBOP costs through the pension adjustment mechanism is misplaced. In that proceeding, the Department did not make any findings with respect to the appropriate ratemaking treatment of pension and PBOP costs for gas acquisition personnel. Rather, we approved a settlement that, among other things, allowed the Company to collect energy efficiency-related pension and PBOP expenses through the pension adjustment mechanism, beginning on January 1, 2016. D.P.U. 14-151, at 8. The Department, however, expressed concern with the appropriateness of this ratemaking treatment and stated that the future ratemaking treatment of energy efficiency-related pension and PBOP costs was subject to subsequent Department Orders. D.P.U. 14-151, at 13. Specifically, the Department stated our intention to investigate the propriety of the continued collection of these costs through the pension adjustment mechanism in the Company's next three-year energy efficiency plan filing. D.P.U. 14-151, at 12-13.

B. Heel Gas

1. Introduction

Heel gas represents the cost of the minimum quantity of LNG that must be maintained within holding tanks and other facilities in order to maintain proper operating pressure and temperature within the LNG facility (Exh. NSTAR-MFF-1, at 80; Tr. 5, at 363-365). The Company proposes to collect a fixed amount of production and storage costs related to the heel gas required for operation at the HOPCO facilities (Exhs. NSTAR-MFF-1, at 81-82; NSTAR-MFF-4, Sch. 1, Sch. 5 at 1 (August 21, 2015)). The Company states that this particular volume of LNG is not delivered to meet peak demand or any other traditional pass-through use to customers (Exh. NSTAR-MFF-1, at 80; Tr. 5, at 363-365, 371).

To calculate its proposed heel gas costs, the Company first determined that the average test year cost of the heel gas inventory that was required to maintain operation of the three LNG tanks at the Hopkinton facility and the two LNG tanks at the Acushnet facility was $2,435,919 (Exh. NSTAR-MFF-4, Sch. 5 (August 21, 2015)). NSTAR Gas applied its proposed weighted average cost of capital (i.e., 7.99 percent) to the average test year cost to arrive at $194,630 (Exh. NSTAR-MFF-4, Sch. MFF-5, at 1 (August 21, 2015); see also NSTAR-MFF-2, Sch. MFF-31, at 1 (August 21, 2015)). Next, the Company multiplied $194,630 by a revenue requirement factor of 1.7115 to yield a proposed heel gas revenue requirement of $333,101 (Exhs. NSTAR-MFF-2, Sch. MFF-4 (August 21, 2015); NSTAR-MFF-4, Sch. MFF-5 (August 21, 2015)).[190] Accordingly, the Company proposes to collect $333,101 in revenues

[190] The revenue requirement factor calculates the revenue increase that is needed to recover the purported operating income shortfall, along with a gross-up for associated federal income taxes, Massachusetts franchise taxes and bad debt expenses attributable to the

through its CGAC (Exhs. NSTAR-MFF-1, at 81-82; NSTAR-MFF-2, Sch. MFF-4 (August 21, 2015); Tr. 5, at 373).

2. Positions of the Parties

a. Attorney General

The Attorney General takes issue with the Company's proposal to include the cost of heel gas inventory in the overall calculation of LNG gas costs (Attorney General Brief at 21-22). According to the Attorney General, the Company will include in its LNG sendout the entire inventory of the LNG tank and all the associated inventory costs (Attorney General Brief at 21). Thus, the Attorney General notes that the cost of sendout calculation will include heel gas inventory and heel gas costs that also are accounted for in the demand charge (Attorney General Brief at 21). The Attorney General contends that this method of accounting for gas costs will lead to either an over- or under-recovery of LNG sendout costs because the Demand Charge recovery is fixed in the instant rate case (Attorney General Brief at 21).

The Attorney General proposes what she contends is a more appropriate method of calculating the average cost of LNG sendout (Attorney General Brief at 21-22). The Attorney General proposes that before NSTAR Gas calculates the average cost of inventory associated with LNG sendout, the Company should (1) subtract the amount of heel gas from the total inventory volume, and (2) subtract the dollar value of heel gas charged through the Demand Charge approved in this proceeding (Attorney General Brief at 21-22). The Attorney General

increase (Exh. NSTAR-MFF-1, at 13-14). NSTAR Gas proposed revenue requirement factor is $1.7115, which means that for the Company to earn $1.00 of operating income, it must recover $1.7115 in revenues (Exhs. NSTAR-MFF-1, at 14; NSTAR-MFF-2, Sch. MFF-4 (August 21, 2015)). The Company also used this revenue requirement factor to determine its proposed overall operating income shortfall of $23.1 million (Exhs. NSTAR-MFF-1, at 14; NSTAR-MFF-2, Sch. MFF-2 (August 21, 2015)).

claims that her proposed method will appropriately account for LNG inventory and costs (Attorney General Brief at 22).

b. Company

The Company argues that its calculation of heel gas costs is consistent with Department precedent (Company Brief at 47-48, citing D.P.U. 13-75, at 89 n. 76; Boston Gas Company/Essex Gas Company/Colonial Gas Company, D.P.U. 10-55-B, at 53 (2010); D.P.U. 10-55, at 622, 633; D.P.U. 12-25, at 112-119). Further, the Company notes that as with all other costs associated with the HOPCO facilities, it is appropriate to recover heel gas costs through the CGAC (Company Brief at 49).

The Company takes issue with the Attorney General's proposed method to calculate the average cost of LNG sendout (Company Brief at 49-50). The Company contends that while it uses the average cost of gas as the basis for the pricing of LNG supply, it only applies that pricing to the quantities of LNG actually withdrawn from the LNG tank (Company Brief at 50, citing Tr. 5, at 370-372). Thus, the Company asserts that because heel gas is never withdrawn from the tank, customers will not be charged for heel gas a second time (i.e., in addition to the amount included in rate base in this case) as suggested by the Attorney General (Company Brief at 50 citing Tr. 5, at 371-372). Further, the Company notes that the cost of gas included in the CGAC is determined based on the beginning gas inventory, plus purchased gas, less the total gas inventory balance (Company Brief at 50, citing Tr. 5, at 375). Thus, according to the Company, "netting out" the heel gas value from the amounts charged to customers for LNG supply would improperly reduce the cost of gas to be recovered from customers and would result in customers receiving the benefit of heel gas without paying for it (Company Brief at 50). For these reasons, the Company asserts that the Department should not accept the Attorney General's recommendation and, instead approve its proposed heel gas costs (Company Brief at 50).

3. Analysis and Findings

Utilities are obligated to provide safe and reliable service to their customers. D.P.U. 10-114, at 76, citing Report to the Legislature Re: Maintenance and Repair Standards for Distribution Systems of Investor-Owned Gas and Electric Distribution Companies, D.P.U. 08-78, at 4 (2009); Incentive Regulation, D.P.U. 94-158, at 3 (1995). Without a sufficient volume of heel gas, a gas company's storage tanks and other facilities would be unable to deliver adequate throughput to the system. D.P.U. 12-25, at 118-119. Although heel gas itself is not delivered to customers in the form of throughput, it does aid in maintaining proper operating pressure and temperature within the LNG facility. D.P.U. 12-25, at 119. While the actual gas molecules may vary over the lifespan of the holding tank or other facility in which the heel gas is stored, the same volume of gas must be maintained in order to ensure proper operation of the facilities, thus making the total composition of the heel gas in question essentially unchanged over time. D.P.U. 12-25, at 119. Therefore, the Department concludes that heel gas may fairly be considered a proper long-term investment that would be eligible for inclusion in rate base if the HOPCO facilities served a distribution-related purpose. See D.T.E. 03-40, at 371-372, D.P.U. 12-25, at 118-119.

Because the HOPCO facilities are exclusively used as a source of gas supply and not for distribution system pressure support, the costs associated with heel gas are appropriately collected through the CGAC. See D.P.U. 14-64, at 38, 41. In this regard, we acknowledge the Attorney General's concern about possible over-collection of gas costs (Attorney General Brief at 21-22). However, we note that the Company proposes to recover the return on its heel gas investment, not the cost of the heel gas investment itself (see Exh. NSTAR-MFF-4, Sch. 5, at 1 (August 21, 2015)). The cost of the physical molecules of heel gas is not included in the HOPCO demand charge or the heel gas component of the CGAC (see Exhs. NSTAR-MFF-4, Sch. 5 (August 21, 2015); NSTAR-DPH-7 (August 21, 2015)). Further, because the Company will never remove heel gas from the LNG tank, the cost of heel gas will not be collected through the CGAC as a gas cost (Tr. 5, at 370-372). Therefore, reducing the Company's LNG costs by the value of heel gas, as proposed by the Attorney General, would prevent the Company from collecting gas costs incurred to serve customers.

Based on these considerations, the Department does not adopt the Attorney General's recommended method calculating the average cost of LNG sendout. Instead, the Department accepts the Company's proposal to include a fixed amount of production and storage costs attributable to heel gas in the CGAC. The Department directs the Company, in its compliance filing, to file an updated version of Exhibit NSTAR-MFF-4, Schedule 5 showing the final heel gas revenue requirement consistent with the directives in this Order.

XII. CAPITAL STRUCTURE AND RATE OF RETURN

A. Introduction

NSTAR Gas proposes a weighted average cost of capital ("WACC") of 7.99 percent, representing the rate of return to be applied to the Company's rate base to determine the total return on its investment (Exhs. AG-7-10, Att. (a) at 1 (Supp.); NSTAR-MFF-2, Sch. MFF-31, at 1 (August 21, 2015)). The WACC is based on: (1) a proposed capital structure consisting of 47.20 percent long-term debt and 52.80 percent common equity; (2) a proposed cost of long-term debt of 5.47 percent; and (3) a proposed rate of return on common equity ("ROE") of 10.25 percent (Exhs. AG-7-10, Att. (a) at 1 (Supp.); NSTAR-MFF-2, Sch. MFF-31, at 1 (August 21, 2015)).

B. Capital Structure

1. Company's Proposal

As of the end of the test year, NSTAR Gas' capitalization consisted of $210,000,000 in first mortgage bonds and $282,681,920 in common equity, corresponding to a capitalization ratio of 42.62 percent long-term debt and 57.38 percent common equity (Exh. NSTAR-MFF-2, Sch. MFF-31, at 1 (August 21, 2015)). NSTAR Gas made several adjustments to the debt and equity components to develop its proposed capital structure (Exhs. NSTAR-MFF-1, at 57-58; NSTAR-Rebuttal-1, at 6; NSTAR-MFF-2, Sch. MFF-31, at 1 (August 21, 2015)).

First, the Company proposes to add to its test year-end long-term debt, $100,000,000 in first mortgage bonds that were issued on September 2, 2015[191] (Exh. AG-7-10, Att. (b) (Supp.)). Accordingly, the Company's total proposed debt component is $310,000,000.

Next, the Company's proposed common equity balance of $346,733,040 includes: (1) a December 2014 capital contribution of $55,000,000 from Northeast Utilities; and (2) an increase of $24,275,853 to retained earnings associated with net income during 2014, less $16,000,000 in dividends paid to shareholders (Exhs. NSTAR-MFF-1 at 57; NSTAR-Rebuttal-1, at 6; NSTAR-MFF-2, Sch. MFF-31, at 1 (August 21, 2015); AG-1-2, Att. (8i) at 14 (Supp.)).

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191 The long-term debt issuance was authorized by the Department in NSTAR Gas Company, D.P.U. 15-01 (2015).

The Company also proposes to include in its capital structure $42,747,432 of unamortized goodwill associated with the BEC Energy-ComEnergy System merger approved in D.T.E. 99-19[192] (Exhs. NSTAR-MFF-5, WP MFF-22, at 4). As described above in Section VI.L.1 above, the 1999 merger between BEC Energy and ComEnergy (the then-parent company of NSTAR Gas) generated an acquisition premium of $490,023,538 (Exhs. NSTAR-MFF-5, WP MFF-22, at 4 (August 21, 2015); Tr. 8, at 741). Of this amount, NSTAR Gas was allocated $69,312,933, representing 14.14 percent of the total acquisition premium (Exhs. NSTAR-MFF-5, WP MFF-22, at 4 (August 21, 2015); NSTAR-Rebuttal-1, at 10-11; AG-6-25, Att. (a); AG-6-25, Att. (d)). The Company treated the net balance of goodwill recorded at the time of the merger as a regulatory asset, amortized over 40 years[193] (Exh. NSTAR-MFF-1, at 42; see also Section VI.L.1, 2 above). The aforementioned adjustments to the Company's test year-end capital structure produce a proposed 47.20/52.80 debt-to-equity ratio (Exhs. NSTAR-Rebuttal-1, at 13-16; NSTAR-MFF-2, Sch. MFF-31, at 1 (August 21, 2015)).

2. Attorney General's Proposal

The Attorney General calculates a proposed WACC of 7.05 percent, based on an ROE of 8.65 percent and a capital structure consisting of 50.33 percent long-term debt and 49.67 percent common equity (Exhs. AG-JRW-1, at 2, 18; JRW-1). The Attorney General developed this

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192 An acquisition premium is generally defined as 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. D.P.U. 93-167-A at 9. The term "goodwill" is also used to describe acquisition premiums.

193 A regulatory asset is an incurred cost for which a regulatory agency such as the Department allows a regulated company to record a deferral to be considered for recovery in the future. NSTAR Pension, D.T.E. 03-47-A at 3 n.2 (2003).

capital structure after removing the net unamortized balance of goodwill from NSTAR Gas' common equity (Exh. AG-JRW-1, at 18).

3. Positions of the Parties

a. Attorney General

The Attorney General argues that the Company's inclusion of goodwill in its capital structure is inappropriate and inconsistent with well-established Department precedent[194] (Attorney General Brief at 40-45, citing D.P.U. 09-39, at 338; D.T.E. 05-27, at 269-272; D.T.E. 03-40, at 319-324; D.P.U. 84-94, at 51-52). According to the Attorney General, the merger-related goodwill represents the price paid in excess of book value of the shares acquired and it is the result of a transfer of wealth from one group of shareholders to another (Attorney General Brief at 41). Accordingly, the Attorney General argues that goodwill does not represent an investment in assets used to provide service to customers (Attorney General Brief at 41). The Attorney General asserts that if the goodwill-related equity is not excluded from capital structure, it has potential to create a higher cost of capital that will increase rates (Attorney General Brief at 40-41).

In addition, the Attorney General disagrees with the Company's contention that if goodwill is recorded as a regulatory asset, it must be supported by actual capitalization (Attorney General Brief at 42). In this regard, the Attorney General notes that a company's actual capital structure and the capital structure used for ratemaking purposes rarely match, and the Department's ratemaking policies have assigned little importance to harmonizing a

194 The Attorney General accepts amortization of the goodwill in NSTAR Gas' cost of service and the recovery of that amortization expense from customers (Attorney General Brief at 42-43).

distribution company's capital structure with the actual capital structure for ratemaking purposes (Attorney General Reply Brief at 25). Moreover, the Attorney General contends that calling the acquisition premium a "regulatory asset" rather than "goodwill" is simply semantics that does not affect the Company's need for capital and, therefore, is irrelevant to the treatment of goodwill for ratemaking purposes (Attorney General Brief at 44).

Based on these arguments, the Attorney General argues that the Department should remove the net unamortized balance of goodwill associated with the 1999 acquisition premium from the Company's actual test year-end common equity (Attorney General Brief at 45, citing Exh. AG-DJE-1, at 26). The Attorney General asserts that the removal of goodwill produces a capital structure consisting of 50.33 percent long-term debt and 49.67 percent common equity (Attorney General Brief at 45). The Attorney General asserts that this capital structure is consistent with the capital structures of the companies in the gas proxy group used to support the Attorney General's proposed cost of equity, as well as the capitalization of NSTAR Gas' parent company, Northeast Utilities (Attorney General Brief at 45, citing Exh. AG-JRW-1, Exh. JRW-5).

b. Company

The Company asserts that it proposed to use its actual capital structure to determine the WACC, consistent with Department precedent (Company Brief at 136, citing D.P.U. 13-75, at 274-276; D.P.U. 12-25, at 386-388; D.P.U. 09-30, at 303-304). The Company argues that the Department has previously recognized capitalization associated with goodwill in capital structures (Company Brief at 155, citing Boston Gas Company, D.P.U. 19470, at 80-81 (1978); Company Reply Brief at 20).

Further, NSTAR Gas contends that the cases cited by the Attorney General for the proposition that goodwill should be removed from capital structure are distinguishable from the instant case (Company Brief at 151-152, 157-158 citing D.P.U. 10-55, at 311; D.P.U. 09-39, at 338; D.T.E. 05-27, at 269-272; D.T.E. 03-40, at 319-324; D.T.E. 98-128, at 52, 56-57; D.P.U. 84-94, at 51-52; Company Reply Brief at 9-20, 24-26). In particular, the Company argues that the Department excluded merger-related goodwill from the capital structures in the cited cases because the goodwill recorded as equity on a company's books had the effect of weighting the company's capital structure too heavily toward equity (Company Brief at 152-156; Company Reply Brief at 21, citing D.P.U. 10-55, at 475; D.P.U. 09-39, at 340-341; D.P.U. 03-40, at 315). In the instant case, NSTAR Gas claims that it created a regulatory asset for the merger-related goodwill but then took steps to eliminate the effect of the regulatory asset on the equity component of the Company's balance sheet (Company Brief at 156).

Specifically, the Company asserts that it implemented a financing and capitalization plan in order to generate an equity component that is suitable for ratemaking (i.e., to protect customers from excessive rates of return and preserve the Company's credit rating) (Company Brief at 156; Company Reply Brief at 14-15, 22). In particular, the Company states that it reduced the percentage of common equity in its capital structure from approximately 80 percent in 2009 to 57 percent in 2010, and maintained that balance through December 31, 2013 (Company Brief at 163, citing Exh. AG-1-7, Att. AG-1-7(b)).

NSTAR Gas maintains, however, that it was still concerned that the Department could find that its common equity ratio was too high for ratemaking purposes (Company Brief at 163). To lessen this possibility, the Company asserts that it undertook a financing and recapitalization plan to bring its common equity ratio within industry norms (Company Brief at 163). The Company asserts that its financing and recapitalization plan included a $55 million common equity contribution from its parent company Northeast Utilities, the $100 million debt issuance described above, and retained earnings updated to December 31, 2014 (Company Brief at 137, citing NSTAR Gas Company, D.P.U. 15-01 (2015); Exhs. NSTAR-MFF-1, at 57-58; NSTAR-Rebuttal-1, at 13-14; NSTAR-MFF-2, Sch. MFF-31 (June 15, 2015); Tr. 8, at 753-755).

According to the Company, these known and measurable changes to its test year-end capital structure result in a proposed capital structure of 47.20 percent long-term debt and 52.80 percent common equity, and represent adjustments to the test year-end capital structure that are typically accepted by the Department (Company Brief at 137). Moreover, the Company maintains that its financing strategy effectively eliminated the negative effect for ratepayers of the regulatory asset on the company's capital structure, and the resulting capital structure is consistent with industry norms[195] (Company Reply Brief at 14-15). In taking the steps to bring its capital structure in line with industry norms, the Company asserts that it achieved a capital structure that is effectively the same as it would have been had the Company only excluded the goodwill from its capital structure and avoided taking the other measures in its financing plan (Company Reply Brief at 15).

Finally, NSTAR Gas argues that the exclusion of the regulatory asset from the

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195 The Company maintains that the median capital structure of its proxy group is 52.98 percent common equity and 47.02 percent long-term debt (Company Reply Brief at 16, citing Exhs. NSTAR-RBH-1, at 49; NSTAR-RBH-13). The Company asserts that its anticipated actual capital structure as of November 1, 2015 is consistent with the median capital structure of the Attorney General's proxy group (i.e., 55.06 percent common equity, 44.76 percent long-term debt, and 0.18 percent preferred stock) (Company Reply Brief at 16).

Company's capital structure could adversely impact the Company's credit rating (Company Brief at 156, 160-164; Company Reply Brief at 22-24). For the reasons described above, NSTAR Gas argues that its proposed capital structure is within ratemaking norms and, therefore, should be accepted by the Department (Company Brief at 153-154, 156).

4. Analysis and Findings

a. Introduction

A company's capital structure typically consists of long-term debt, preferred stock, and common equity. D.P.U. 07-71, at 122; D.T.E. 03-40, at 319; D.T.E. 01-56, at 97; Pinehills Water Company, D.T.E. 01-42, at 17-18 (2001). 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 its revenue requirements. D.P.U. 07-71, at 122; D.T.E. 03-40, at 319; D.T.E. 01-42, at 18; D.P.U. 86-149, at 5.

The Department will normally accept a company's test year-end capital structure, allowing for known and measurable changes.[196] D.T.E. 03-40, at 323-324; D.P.U. 88-67 (Phase I) at 174; D.P.U. 84-94, at 50. Within a broad range, the Department will defer to the management of a utility in decisions regarding the appropriate capital structure and normally will accept the utility's test year-end capital structure, unless the capital structure deviates substantially from sound utility practice. Mystic Valley Gas Company v. Department of Public

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[196] Adjustments to test year-end capitalization to recognize redemptions, retirements, or issuances of new debt or equity are allowed, provided that they are known and measurable and the proposed issuance or retirement of securities has actually taken place by the date of the Order. D.T.E. 03-40, at 323.

Utilities, 359 Mass. 420, 428 429 (1971); High Wood Water Company, D.P.U. 1360, at 26-27 (1983); Blackstone Gas Company, D.P.U. 1135, at 4 (1982); see also Cambridge Electric Light Company, D.P.U. 20104, at 42 (1979).

b. Debt Issuance

The $100 million debt issuance approved by the Department in D.P.U. 15-01 was issued by the Company on September 2, 2015 (Exh. AG-7-10, Att. (b) (Supp.)). Therefore, the Department finds that the debt issuance represents a known and measurable change to test year-end capitalization. Accordingly, the Department accepts this proposed adjustment to the Company's capital structure. Aquarion Water Company of Massachusetts, D.P.U. 11-43, at 204-205 (2012); D.P.U. 07-71, at 122-123; D.T.E. 05-27, at 272; D.P.U. 84-94, at 52-53.

c. Paid-in Capital/Goodwill

NSTAR Gas' proposed common equity balance of $346,733,040 consists of: (1) $71,425,000 in common stock; (2) $270,954,238 in paid-in capital, and (3) $4,353,802 in retained earnings (Exhs. NSTAR-MFF-2, Sch. MFF-31, at 1 (August 21, 2015); AG-1-2(8i), at 13 (Supp. 1)). The Company's paid-in capital account includes $55,000,000 in the form of a capital contribution from Northeast Utilities in December 2014, and $42,747,432 in goodwill associated with the 1999 merger of BEC Energy and ComEnergy (Exhs. NSTAR-MFF-2, Sch. MFF-31, at 1 (August 21, 2015); NSTAR-Rebuttal-1, at 13-14; AG-1-2(8h), at 11; AG-1-34, Att. (a) at 3; AG-1-34, Att. (a) at 7 (Supp.); NSTAR-MFF-5, WP MFF-22, at 4 (August 21, 2015); AG-6-29, Att.).

The capital contribution from Northeast Utilities was intended to fund the Company's operations and to create a more balanced capital structure (Exhs. NSTAR-MFF-1, at 57;

NSTAR-Rebuttal-1, at 17-18; NSTAR-Rebuttal-2, at 8-9). See also D.P.U. 15-01, at 2. The Department finds that the $55,000,000 capital contribution is a known and measurable change to test year-end capitalization. Therefore, the Department accepts this proposed adjustment to the Company's capital structure.[197] D.P.U. 10-70, at 241; D.P.U. 07-71, at 122.

The paid-in capital at issue in NSTAR Gas' proposed capital structure is the net unamortized balance of goodwill associated with the 1999 acquisition premium (Exh. NSTAR-MFF-5, WP MFF-3, at 3-4 (August 21, 2015)). The Department has excluded goodwill from capitalization associated with acquisition premiums from utility capitalization for ratemaking purposes. D.P.U. 10-55, at 473-475 (goodwill in the form of intercompany notes excluded); D.P.U. 09-39, at 338 (goodwill excluded by company); D.P.U. 08-35, at 189 (use of hypothetical capital structure rejected, and goodwill excluded from capitalization); D.T.E. 05-27, at 269, 272 (goodwill removed from capitalization); D.T.E. 03-40, at 320-323 (goodwill removed from capitalization). However, on at least one occasion, the Department has found it appropriate to include the capitalization associated with acquisition premiums in capitalization for ratemaking purposes. Boston Gas Company, D.P.U. 19470, at 80-81 (1978). For the reasons discussed below, the Department accepts the Company's proposal to include the capitalization

[197] The capital contributions are not stock issuances as defined in G.L. c. 164, § 14 and, therefore, are not subject to a determination under G.L. c. 164, § 14 that the contributions were reasonably necessary to accomplish some legitimate purpose in meeting a company's public service obligations. D.P.U. 10-70, at 241-242, citing Fitchburg Gas and Elec. Light Co. v. Dep't of Pub. Utils., 395 Mass. 836, 842 (1985), Fitchburg Gas and Elec. Light Co. v. Dep't of Pub. Utils., 394 Mass. 671, 678 (1985). Capital contributions to a subsidiary are outside of the regulatory review process and an adjustment to the subsidiary's capital structure may result in a higher rate of return. Accordingly, the Department will continue to examine parent holding company capital contributions for potential adverse rate effects. D.P.U. 10-70, at 242.

associated with goodwill attributable to the BEC Energy-ComEnergy System merger for the purposes of determining its capital structure.

The Department's ultimate focus when reviewing capital structure is to ensure that a utility's capital structure does not deviate substantially from sound utility practice. D.P.U. 1360, at 26-27; D.P.U. 1135, at 4. As of the end of the test year, NSTAR Gas' capitalization consisted of 42.62 percent long-term debt and 57.38 percent common equity (Exh. NSTAR-MFF-2, Sch. MFF-31, at 1 (August 21, 2015)). Given the extent to which this capital structure was based on common equity, it is likely that the Department would have found that such structure deviated substantially from sound utility practice and that an imputed capital structure was warranted.[198] D.P.U. 1360, at 26-27; D.P.U. 1135, at 4.

Recognizing that imputation was a possibility, the Company undertook a financing and capitalization plan in order to generate a more balanced capital structure (Exhs. NSTAR-MFF-1, at 57-58; NSTAR-Rebuttal-1, at 13-14). Specifically, as discussed above, the Company received a $55,000,000 capital contribution from Northeast Utilities in December 2014 (Exhs. NSTAR-MFF-1 at 57; NSTAR-Rebuttal-1, at 6; NSTAR-MFF-2, Sch. MFF-31, at 1 (August 21, 2015); AG-1-2, Att. (8i) at 14 (Supp.)). In addition, the Company issued $100,000,000 in first mortgage bonds September 2, 2015 (Exh. AG-7-10, Att. (b) (Supp.)). As a result of this financing and capitalization plan, NSTAR Gas' updated capitalization consisted of

[198] In cases where the exclusion of goodwill has produced a capital structure that was overly weighted towards equity, the Department has imputed a capital structure. D.P.U. 09-39, at 339-341; D.T.E. 03-40, at 324-325.

47.86 percent long-term debt and 52.14 percent common equity[199] (see Exh. NSTAR-MFF-2, Sch. MFF-31, at 1 (August 21, 2015)).

As discussed in Section VI.L.4 above, the Department has reduced the Company's goodwill balance to $41,876,517 for purposes of determining the recovery of acquisition premiums.[200] Consistent with this treatment, the Department finds it appropriate to reduce the goodwill balance in NSTAR Gas' capital structure. In the section below, the Department makes an adjustment to the Company's proposed retained earnings balance. Together, these adjustments produce a capital structure consisting of 47.90 percent debt and 52.10 percent common equity.

The Department finds that, with the inclusion of goodwill, the Company's capital structure remains balanced and is not overly weighted towards debt or equity. The Department finds that this capital structure is within the bounds of sound utility practice and will not adversely affect the Company's ability to access the capital markets. Therefore, we and that it is not necessary to impute a capital structure for NSTAR Gas. Cf. D.T.E. 03-40, at 319; D.P.U. 1360, at 26-27; D.P.U. 1135, at 4.

Based on the foregoing, the Department finds it appropriate to include the Company's goodwill associated with the 1999 acquisition premium in NSTAR Gas' capital structure. Our findings here only address the appropriate treatment of goodwill in the Company's capital structure for ratemaking purposes. The Department's findings here do not affect the findings in

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199 This debt-to-equity ratio excludes the effect of NSTAR Gas' proposed adjustment to its retained earnings balance, as addressed below.

200 In Section VI.L.4 above, the Department adjusted the $42,747,432 in goodwill by $870,916 associated with loss contingencies.

Section VI.L.4 above regarding the Company's recovery of its allocated portion of the acquisition premium, including goodwill, in rates.

d. Retained Earnings

The Company's proposed retained earnings balance of $4,353,802 compares to a retained earnings deficit of $4,317,783 as of December 31, 2013 (Exh. AG-1-2, Att. (8i) at 13, 15 (Supp.)). This increase is attributable to an increase in net income for 2014 of $24,671,585, less $16,000,000 in dividends paid (Exh. AG-1-2, Att. (8i) at 15 (Supp.)).

Retained earnings balances fluctuate from one quarter to another to a greater degree than other components of capitalization, such as long-term debt and common stock. For this reason, the Department does not generally consider post-test year adjustments to retained earnings balances to be more representative than test year-end balances.[201] D.P.U. 09-39, at 338; Milford Water Company, D.P.U. 92-101, at 36-37 (1992); D.P.U. 1350, at 156; Massachusetts Electric Company, D.P.U. 1133, at 21-22 (1982); Boston Edison Company, D.P.U. 18515, at 54 (1975). Accordingly, the Department does not approve NSTAR Gas' proposed post-test year adjustment to retained earnings as of December 31, 2014 and, instead, will use the Company's retained earnings deficit of $4,317,783 as of December 31, 2013 for the purpose of determining the common equity balance in its capital structure.

201 In D.P.U. 14-120, at 121-122, the Department recognized a retained earnings adjustment for a small water company where the company's common equity balance had declined by more than 23 percent since the end of its test year as a result of operating losses and, therefore, the Department found that the proposed adjustment was representative of future retained earnings.

e. Conclusion

Based on the foregoing analysis, the Department finds that the Company's capital structure consists of $310,000,000 in long-term debt and $337,190,540 in common equity, representing: (1) $71,425,000 in common stock; (2) $270,083,323 in paid-in capital, and (3) negative $4,317,783 in retained earnings. These balances produce a capital structure consisting of 47.90 percent long-term debt and 52.10 percent common equity. The Department finds that this capital structure is within the bounds of sound utility practice. D.T.E. 03-40, at 319; D.P.U. 1360, at 26-27; D.P.U. 1135, at 4. Therefore, the Department will apply this capital structure for ratemaking purposes. The effects of this capital structure on the Company's WACC are provided in Schedule 5 of this Order.

C. Cost of Debt

1. Introduction

As of the end of the test year, the Company had four series of debt issues outstanding, identified as Series J, K, M, and N, with principal amounts ranging between $25,000,000 and $125,000,000 (Exhs. NSTAR-MFF-2, Sch. MFF-31, at 1-2 (August 21, 2015); AG-7-10, Att. (b) at 2 (Supp.)). These debt instruments have maturities of between ten and 30 years, and carry interest rates ranging from 4.46 percent and 9.95 percent (Exhs. NSTAR-MFF-2, Sch. MFF-31, at 1-2 (August 21, 2015); AG-7-10, Att. (b) at 2 (Supp.)). On September 2, 2015, the Company issued $100,000,000 in Series O debt at an interest rate of 4.35 percent. D.P.U. 15-01, Compliance Filing (September 4, 2015).

The Company calculated the effective interest rates for each of its debt issuances by dividing the sum of the annual interest expense of $16,661,000 and the annual amortization of issuance costs of $104,000 (i.e., $16,915,000), by the outstanding debt balance of $309,317,000[202] (Exh. NSTAR-MFF-2, Sch. MFF-31, at 2 (August 21, 2015)). This calculation produces an overall effective cost of debt of 5.47 percent (Exhs. AG-7-10, Att. (a) at 1-2 (Supp.); NSTAR-MFF-2, Sch. MFF-31, at 2 (August 21, 2015)).

2. Position of the Parties

a. Attorney General

The Attorney General objects to the Company's proposed deduction of unamortized debt issuance costs from the principal balance of long-term debt used to determine the interest rate on NSTAR Gas' long-term debt (Attorney General Brief at 45, citing Exh. AG-18-36). The Attorney General argues that the Company's proposal is inconsistent with Department precedent and, therefore, she argues that NSTAR Gas should be required to recalculate its cost rate of long-term debt using the outstanding principal, with no adjustment for issuance costs (Attorney General Brief at 46, citing D.P.U. 92-78, at. 91-92; D.P.U. 90-121, at 159-161; see also Boston Edison Company, D.P.U. 86-71, at 12 (1986)).

b. Company

NSTAR Gas argues that its proposed cost of long-term debt represents the Company's actual cost associated with its debt issuances[203] (Company Brief at 138-139, citing Exhs. NSTAR-MFF-1, at 57-58; NSTAR-MFF-2, Sch. MFF-31 (June 15, 2015)). Further, the Company contends that its proposed long-term debt rate appropriately recognizes the actual

202 The Company characterizes this outstanding debt as being equal to the "carrying value" of the debt (Exh. NSTAR-MFF-2, Sch. MFF-31, at 2 (August 21, 2015)).

203 At the time NSTAR Gas filed its briefs, the $100,000,000 in long-term debt approved in D.P.U. 15-01 had not yet been issued.

cost of debt associated with the $100,000,000 debt issuance approved by the Department in D.P.U. 15-01 and, therefore, constitutes a known and measurable change to its test year cost of debt (Company Brief at 139, citing Exh. NSTAR-Rebuttal-1, at 14; NSTAR-MFF-2, Sch. MFF-31 (June 15, 2015); D.P.U. 90-121, at 157).

3. Analysis and Findings

Costs associated with the issuance of long-term debt such as issuance costs, debt discounts, and other amortizations are necessary operating expenses and are expected to occur from time to time as long-term debt is issued by a company. D.P.U. 10-114, at 294; D.T.E. 01-56, at 99; D.P.U. 90-121, at 160. The appropriate ratemaking treatment of issuance costs is to include them in the effective cost of debt by amortizing the issuance costs over the life of the issue without providing a return on the unrecovered portion of the issuance costs. See D.P.U. 92-78, at 91-92; D.P.U. 90-121, at 160-161; D.P.U. 86-71, at 12.

While NSTAR Gas' proposed cost of debt appropriately considers amortized issuance costs, the Company has added issuance costs to its interest expense and deducted unamortized issuance costs from its outstanding debt balance (Exh. NSTAR-MFF-2, Sch. MFF-31, at 2 (August 21, 2015)). By reducing its outstanding debt balance by unamortized issuance costs, the Company's proposed cost of debt will result in an over-collection of its associated issuance costs.[204] D.P.U. 10-114, at 294; D.P.U. 90-121, at 160-161. Therefore, the Department rejects the Company's proposed cost of long-term debt.

[204] Unamortized debt expense is not a valuation account on the debt but, in essence, a prepaid item. D.P.U. 10-114, at 294 n.185.

NSTAR Gas reported that the issuance costs on its outstanding long-term debt issuances range from $51,000 on its Series J debt to $416,000 on its Series N debt, for a total of $683,000[205] (Exh. NSTAR-MFF-2, Sch. MFF-31, at 2 (August 21, 2015)). The $683,000 in total issuance costs, amortized over the terms of the respective debt issuances, produces an annual amortization of $104,000 (Exh. NSTAR-MFF-2, Sch. MFF-31, at 2 (August 21, 2015)). The Company also reported an annual interest expense on its outstanding long-term debt issuances of $12,415,000 (Exh. NSTAR-MFF-2, Sch. MFF-31, at 2 (August 21, 2015)). This interest expense does not include the interest on its Series O debt, which at 4.35 percent is equal to $4,350,000.[206] See D.P.U. 15-01, Compliance Filing (September 4, 2015). The sum of the annual amortization of $104,000 and total annual interest expense of $16,765,000 (including interest on the Company's Series O debt) is $16,869,000 (see Exh. NSTAR-MFF-2, Sch. MFF-31, at 2 (August 21, 2015)). The $16,869,000, divided by the principal amount of $310,000,000, produces an effective interest rate of 5.44 percent (see NSTAR-MFF-2, Sch. MFF-31, at 2 (August 21, 2015)). Accordingly, the Department will apply a cost of long-term debt of 5.44 percent to determine the Company's weighted average cost of capital.

D. Proxy Groups

1. Company's Proxy Group

NSTAR Gas is a wholly-owned subsidiary of Northeast Utilities and, therefore, has no public market for its stock. Accordingly, NSTAR Gas presented its cost of equity analysis using

205 NSTAR Gas did not provide the issuance costs associated with its Series O debt, because that debt was issued after the Company submitted its August 21, 2015 cost of service updates (Exh. NSTAR-MFF-2, Sch. MFF-31, at 2 (August 21, 2015)).

206 In Section XII.B.4.b above, the Department found that this debt issuance was a known and measurable change to test year-end capitalization.

the capitalization and financial statistics of a proxy group of eight natural gas utilities (Exh. NSTAR-RBH-1, at 12). The Company selected its proxy group from a group of eleven companies classified as "natural gas utilities" by Value Line Investment Survey ("Value Line") (Exh. NSTAR-RBH-1, at 11). From that group, the Company states that it chose companies that: (1) are included in Value Line; (2) have investment grade senior bond and/or corporate credit ratings from Standard & Poor's Financial Services, LLC ("S&P"); and (3) have been covered by at least two utility industry equity analysts (Exh. NSTAR-RBH-1, at 11). As part of this process, NSTAR Gas states that it excluded: (1) companies with regulated electric operations or significant unregulated activities; (2) companies with regulated natural gas utility operating income comprising less than 60 percent of the total income for that company; (3) companies that do not consistently pay quarterly cash dividends; and (4) companies that are currently involved in merger activities or other significant transactions (Exh. NSTAR-RBH-1, at 11-12).

2. Attorney General's Proxy Group

In her cost of equity analysis, the Attorney General evaluates the return requirements of investors on the common stock of a proxy group of eight publicly held gas distribution companies (Exhs. AG-JRW-1, at 1, 16; JRW-4). These selected companies are listed in AUS Utility Reports as a natural gas distribution, transmission and/or integrated gas company, and as a natural gas utility by Value Line Standard Edition (Exh. AG-JRW-1, at 16). The selected companies also have an investment grade bond rating by Moody's Investor Service ("Moody's") and S&P (Exh. AG-JRW-1, at 16).

The Attorney General states that she eliminated two companies from her proxy group due to their low percentage of revenues from regulated gas operations (Exh. AG-JRW-1, at 16). The

Attorney General's proxy group includes one company that NSTAR Gas excluded from its proxy group (Exh. AG-JRW-4).

The median operating revenues for the Attorney General's proxy group companies is $1,829,800,000 and median net plant for the group is $3,461,400,000 (Exh. AG-JRW-1, at 17). The group receives an average of 67 percent of their revenues from regulated gas operations, has an A3 Moody's bond rating,[207] an A- bond rating from S&P, a current common equity ratio of 46.2 percent, and an earned return on common equity of ten percent (Exhs. AG-JRW-1, at 17; AG-JRW-15).

3. Positions of the Parties

a. Attorney General

The Attorney General contends that her proxy group is of comparable investment risk for NSTAR Gas because the Company's S&P issuer credit rating of A- is equivalent to the average issuer credit rating for her proxy group (Attorney General Brief at 48). Therefore, the Attorney General argues that it is appropriate to rely on her proxy group to determine NSTAR Gas' cost of common equity (Attorney General Brief at 48).

b. Company

The Company argues that its proxy group is consistent with Department precedent because the eight companies in the group have common stock that is publicly traded and the companies are generally of comparable investment risk to NSTAR Gas (Company Brief at 143, citing D.P.U. 13-75, at 285-286; D.P.U. 12-25 at 395-397, 402; D.P.U. 10-55, at 479-480, 511).

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[207] Bonds rated "A" by Moody's are judged to be upper-medium grade and are subject to low credit risk. The modifier "3" indicates a mid-range ranking. See Moody's Investor Services Rating Symbols and Definitions, available at www.moodys.com/Pages/amr002002.aspx.

Further, the Company argues that the adoption of revenue decoupling and/or infrastructure investment mechanisms plays no role in differentiating its proxy group from the Company by risk and, therefore, does not undermine their comparability to NSTAR Gas (Company Brief at 148-149). More specifically, the Company maintains that each of its proxy group companies has a form of decoupling in place for most, if not all, of its gas utility subsidiaries (Company Brief at 143, citing Exhs. NSTAR-RBH-1, at 37; DPU 15-7, Att. (a); DPU 15-7, Att. (b)). In addition, the Company maintains that seven of its eight proxy companies have infrastructure investment mechanisms in place (Company Brief at 143, citing Exhs. NSTAR-RBH-Rebuttal-1, at 56; DPU 15-7, Att. (a); DPU 15-7, Att. (b)).

4. Analysis and Findings

The Department has accepted the use of a proxy group of companies for evaluation of a cost of equity analysis when a distribution company does not have common stock that is publicly traded. See D.P.U. 08-35, at 176-177; Fitchburg Gas and Electric Light Company, D.T.E. 99-118, at 80-82 (2001); D.P.U. 92-78, at 109-110. The Department has stated that companies in the proxy group must have common stock that is publicly traded and must be generally comparable in investment risk. D.P.U. 1300, at 97.

In our evaluation of the proxy groups used by NSTAR Gas and the Attorney General, we recognize that it is neither necessary nor possible to find a group in which the companies match the Company in every detail. See D.T.E. 99-118, at 80; D.P.U. 87-59, at 68; D.P.U. 1100, at 135-136. Rather, we may rely on an analysis that employs valid criteria to determine which companies will be in the proxy group, and that provides sufficient financial and operating data to discern the investment risk of the Company versus the proxy group. See D.T.E. 99-118, at 80; D.P.U. 87-59, at 68; D.P.U. 1100, at 135-136.

The Department expects diligence on the part of parties in assembling proxy groups that will produce statistically reliable analyses required to determine a fair rate of return for the Company. See D.P.U. 10-55, at 480-482. Overly exclusive selection criteria may affect the statistical reliability of a proxy group, especially if such screening criteria result in a limited number of companies in the proxy group. D.P.U. 10-55, at 480-482. The Department expects parties to limit criteria to the extent necessary to develop a larger as opposed to a narrower proxy group. D.P.U. 10-114, at 299; see D.P.U. 10-55, at 481-482. To the extent that a particular company's characteristics differ from those of the others in a proxy group, those differences should be identified in sufficient detail to enable a reviewer to discern any effects on investment risk. D.P.U. 10-114, at 299; D.P.U. 10-55, at 480-482.

We find that NSTAR Gas and the Attorney General each employed a set of valid criteria to select their respective proxy groups, and that they each provided sufficient information about the proxy groups to allow the Department to draw conclusions about the relative risk characteristics of the Company versus the members of the proxy groups. See D.P.U. 12-25, at 402; D.P.U. 09-30, at 307. Therefore, the Department will rely on those proxy groups to determine the Company's required cost of equity.

Our acceptance of these groups notwithstanding, we raise three factors that we also will take into consideration in determining the appropriate ROE for the Company. First, the Company's decoupling mechanism is but one form of a wide range of revenue recovery mechanisms used by the companies in the two different proxy groups that the financial market and regulatory community consider to be revenue stabilization mechanisms. D.P.U. 10-114, at 300; D.P.U. 10-55, at 482; D.P.U. 09-30, at 308; see also D.P.U. 07-50-A at 72. Second, the Company's GSEP program represents an infrastructure recovery mechanism used by the companies in the two different proxy groups, and serve to address cash flow and regulatory lag associated with infrastructure replacement (Exhs. NSTWR-WJA-1, at 17-20; DPU-15-7, Atts. (a), (b); DPU-15-5). Finally, some of the companies in the Company's proxy groups are involved in non-regulated businesses beyond distribution activities (Exhs. AG-8-3, Att. (b) at 91-97; JRW-10, AUS Utilities Reports, passim). These business activities potentially make these companies more risky, all else being equal and, in turn, potentially more profitable than the Company. D.P.U. 11-01/D.P.U. 11-02, at 385; D.P.U. 10-114, at 300; D.P.U. 09-30, at 309; D.P.U. 07-71, at 135. Therefore, while we accept the Company's and the Attorney General's proxy groups as a basis for evaluating their cost of capital proposals, we also will consider the particular characteristics of the Company as compared to members of the proxy groups when determining the appropriate ROE.

E. Return on Equity

1. Company's Proposal

The Company applied the financial data from its proxy group to three cost of equity models: (1) the discounted cash flow ("DCF") model, including the constant growth and multi-stage forms; (2) the capital asset pricing model ("CAPM"); and (3) the bond yield plus risk premium model ("risk premium model") (Exh. NSTAR-RBH-1, at 3). Based on the results of these models[208] and considering the Company's business risks relative to its proxy group, NSTAR Gas determined that its ROE is in the range of ten percent to 10.50 percent (Exh. NSTAR-RBH-Rebuttal-1, at 60). Specifically, the Company states that it considered its proposed decoupling mechanism, flotation costs, and the effect of the Company's ROE on its financial integrity (Exh. NSTAR-RBH-1, at 3). Accordingly, the Company requests that the Department approve an ROE for NSTAR Gas of 10.25 percent[209] (Exh. NSTAR-RBH-1, at 2-3).

2. Attorney General's Proposal

The Attorney General applied the financial data from her proxy group to two cost of equity models: (1) the DCF; and (2) the CAPM (Exh. AG-JRW-1-at 2, 50). The Attorney General's DCF analysis produced an ROE of 8.65 percent, while her CAPM analysis resulted in an ROE of 8.40 percent (Exhs. AG-JRW-1, at 40, 50; JRW-10, at 1; JRW-11, at 1). Giving greater weight to the DCF model, the Attorney General concludes that the appropriate ROE for NSTAR Gas is 8.65 percent (Exh. AG-JRW-1, at 50).

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208 On the low end, the Company's constant growth DCF analysis produced an ROE of 7.89 percent (Exh. NSTAR-RBH-Rebuttal-1, at 59, Table 5a). On the high end, the Company's CAPM analysis produced an ROE of 11.44 percent (Exh. NSTAR-RBH-Rebuttal-1, at 60, Table 5b).

209 In the Company's previous rate case, which was the product of a settlement, the Department approved an allowed ROE of 13.0 percent for purposes of regulatory mechanisms where a ROE component was required (e.g., allowance for funds used during construction, purchased gas working capital, and the environmental remediation factor). D.P.U. 91-60, Order on Offer of Settlement at 2. In the Company's last fully adjudicated rate case, the Department set an allowed ROE of 13.25 percent. D.P.U. 87-122, at 109.

3. Positions of the Parties

a. Attorney General

The Attorney General challenges the financial modeling practices and observations that the Company uses to support its view that current market conditions and utility cost of equity trends warrant the higher ROE that it proposes (Attorney General Brief at 63-65). In support of her position, the Attorney General argues that: (1) the utility industry is one of the lowest risk industries in the United States and, as such, its cost of equity capital is amongst the lowest in the United States; (2) NSTAR Gas' risk conforms to this low-risk industry category as measured by its proxy group's S&P issuer credit rating of A-; (3) historically low interest rates and long-term bond yields have depressed capital costs; and (4) authorized ROEs for gas distribution companies have decreased in recent years (Attorney General Brief at 50, 57, 64, citing Exhs. AG-JRW-1, at 50-51; JRW-2; JRW-3; JRW-8). Further, the Attorney General argues that NSTAR Gas' proposed cost of capital is based on "fatally flawed" DCF, CAPM, and risk premium modeling analyses (as discussed below) (Attorney General Brief at 63).

While acknowledging that her recommended ROE of 8.65 percent is low by historic standards, the Attorney General asserts that her recommended ROE nonetheless satisfies the requirements of Federal Power Commission v. Hope Natural Gas Company, 320 U.S. 591 (1944) ("Hope") and Bluefield Water Works and Improvement Company v. Public Service Commission of West Virginia, 262 U.S. 679 (1923) ("Bluefield") (Attorney General Brief at 64). In support of her position, the Attorney General argues that NSTAR Gas' average earned ROE during the period 2010 to 2013 was seven percent and its A- S&P issuer credit rating is equivalent to the gas proxy group average (Attorney General Brief at 65). Thus, the Attorney General asserts that an ROE of 8.65 percent conforms to the Hope and Bluefield directives that establish returns on capital should be: (1) comparable to returns investors expect to earn on other investments of similar risk; (2) sufficient to assure confidence in the company's financial integrity; and (3) adequate to maintain and support the company's credit and to attract capital (Attorney General at 65).

b. Company

NSTAR Gas argues that its proposed ROE of 10.25 percent reflects current capital market conditions and is the result of a number of widely accepted common equity cost models (Company Brief at 149). NSTAR Gas contends that the Department is obligated to provide a return for the Company commensurate with the returns for similar enterprises having corresponding risks (Company Brief at 140, citing Attorney General v. Department of Public Utilities, 392 Mass. 266 (1984), quoting Hope., 320 U.S. 603). In this regard, the Company notes that its proposed ROE of 10.25 percent is based, in part, on a proxy group of gas distribution companies that have comparable risk given that these utility companies, in general, have already implemented revenue stabilization mechanisms and have infrastructure tracking mechanisms (Company Brief at 140, citing Exh. NSTAR-RBH-1, at 11-13). Thus, according to NSTAR Gas, any reduction in the ROE because the Company has a decoupling or infrastructure tracking mechanism would be inappropriate (Company Brief at 140).

Further, NSTAR Gas argues that the ROE authorized in this case must allow the Company to maintain its credit and ability to attract capital (Company Brief at 140-141, citing Boston Edison v. Department of Public Utilities, 375 Mass. 305, 315 (1978), citing Hope at 603; New England Telephone & Telegraph Co. v. Department of Public Utilities, 327 Mass. 81, 88 (1951); Massachusetts Electric Company v. Department of Public Utilities, 376 Mass. 294, 299 (1978); Attorney General v. Department of Public Utilities, 392 Mass. 262, 265 (1984)). According to NSTAR Gas, in setting the ROE in this case the Department must recognize the Company's need to attract capital on a going forward basis and, without a fair return, the Company will not be able to attract investors to maintain safe and reliable service (Company Brief at 141). In this regard, the Company asserts that the Attorney General's recommended ROE of 8.65 percent will deny the Company a fair rate of return and impair its ability to attract capital (Company Brief at 150; Company Reply Brief at 4). The Company also notes that the Attorney General's recommended ROE represents a significant departure from the returns granted by the Department over the past two decades and by other public utility commissions in recent years[210] (Company Reply Brief at 4).

Finally, the Company argues that the cost of capital has become more volatile during 2015 versus 2014 due to actions by the Federal Reserve (Company Reply Brief at 5, citing Exh. NSTAR-RBH-1, at 44-45; Tr. 8, at 720). The Company argues that such volatility, coupled with recent authorized gas utility ROEs in the range of 9.5 and ten percent, provides ample support for the Company's requested ROE of 10.25 percent (Company Reply Brief at 5).

210 The Company argues that other gas companies have authorized ROEs that are materially higher than the Attorney General's recommended ROE in this case (Company Reply Brief at 4). For instance, the Company notes that the average authorized ROE for the companies in both the Company's and the Attorney General's proxy groups was 9.74 percent during 2012; 9.58 percent during 2013; and 9.81 percent during 2014 (Company Reply Brief at 4, citing Exh. NSTAR-RBH-Rebuttal-1, at 12). Further, the Company contends that the Attorney General's own expert cited an average authorized ROE for gas distribution companies in 2014 of 9.78 percent (Company Reply Brief at 5, citing Exh. AG-JRW-1, at 6). Finally, the Company claims that within the year prior to mid-2015, approximately half of the authorized ROEs granted to gas utilities were ten percent or above (Company Reply Brief at 4, citing Exh. NSTAR-RBH-Rebuttal-1, at 10-11).

4. Discounted Cash Flow Model

a. Company's Proposal

The DCF model is based on the premise that a stock's current price is equal to the present value of the future dividends that investors expect to receive (Exh. NSTAR-RBH-1, at 16). The Company used both a constant growth and a multi-stage DCF model (Exh. NSTAR-RBH-1, at 15, 23).

The constant growth DCF model comprises a forward-looking dividend yield component and an expected dividend growth rate into perpetuity as represented by the following formula:

$$P_0 = D_1 / (1+k) + D_2 / (1+k)^2 + ... + D_\infty / (1+k)^\infty$$

where P_0 is today's stock price, D_1, D_2, etc. are all expected future dividends, and k is the discount rate (i.e., the investor's required ROE) (Exh. NSTAR-RBH-1, at 16). The Company calculated the dividend yield component based on the current annualized dividends of its proxy group (Exh. NSTAR-RBH-1, at 17). For the expected growth rate, the Company used a consensus of the Zacks, First Call, and Value Line surveys to estimate a long-term earnings growth rate[211] (Exhs. NSTAR-RBH-1, at 21; NSTAR-RBH-Rebuttal-1, at 58; NSTAR-RBH-Rebuttal-2).

To address what it contends are certain limiting assumptions underlying the constant growth model, NSTAR Gas also used a multi-stage DCF model[212] (Exh. NSTAR-RBH-1, at 23).

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211 The Company updated its constant and multi-stage DCF and CAPM results with adjusted data from April 30, 2015, and presented the new results in a May 20, 2015, filing with the Department (Exhs. NSTAR-RBH-Rebuttal-1, at 58, 60; NSTAR-RBH-Rebuttal-2; NSTAR-RBH-Rebuttal 4; NSTAR-RBH-Rebuttal-7).

212 Unlike the constant growth mode, the multi-stage DCF model enables the analyst to specify growth rates over multiple time periods (Exh. NSTAR-RBH-1, at 24).

The Company applied a three-stage DCF model that employs multiple earnings growth rate and payout rate assumptions (Exh. NSTAR-RBH-1, at 23-26). Earnings growth and payout ratio assumptions change throughout the three stages of this model[213] (Exh. NSTAR-RBH-1, at 24-27). In particular, the Company employed a long-term gross domestic product ("GDP") growth rate of 5.64 percent[214] (Exh. NSTAR-RBH-1, at 28).

The Company's constant growth DCF model produced a cost of equity range of 7.89 percent to 10.22 percent (Exhs. NSTAR-RBH-1, at 23; NSTAR-RBH-Rebuttal-1, at 58-59; NSTAR-RBH-Rebuttal-2). Alternately, NSTAR Gas' multi-stage DCF model produced a cost of equity range of 9.36 percent to 10.06 percent (Exhs. NSTAR-RBH-1, at 29; NSTAR-RBH-Rebuttal-1, at 58-59; NSTAR-RBH-Rebuttal-4).

b. Attorney General's Proposal

The Attorney General relies on a constant growth DCF model, reasoning that the public utility business is in the steady-state (or constant-growth) stage of a three-stage DCF

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213 In the first stage, earnings growth is based on average earnings per share growth as reported by Value Line, Zacks, and First Call, and a company-specific payout ratio from Value Line is used (Exh. NSTAR-RBH-1, at 27). In the second stage, earnings growth transitions to a long-term GDP growth rate and company-specific payout ratios transition to the long-term industry payout ratio (Exh. NSTAR-RBH-1, at 27). In the third stage, earnings growth is based on the long-term GDP growth rate, while the payout ratio is based on the long-term expected payout ratio (Exh. NSTAR-RBH-1, at 27-28). The terminal value is based on the expected dividend divided by the difference between the cost of equity (i.e., the discount rate) and the long-term expected growth rate (Exh. NSTAR-RBH-1, at 25-27).

214 The Company's GDP growth rate is the compound growth rate in chain-weighted GDP for the period from 1929 through 2013 (Exh. NSTAR-RBH-1, at 28). The 2.29 percent rate of inflation is a compound annual forward rate starting in ten years (i.e., 2024) and is based on 30-day average projected spread between yields on long-term nominal treasury securities and long-term treasury inflation-protected securities (Exh. NSTAR-RBH-1, at 28).

(Exh. AG-JRW-1, at 30). To determine the cost of capital using her constant growth DCF model, the Attorney General summed the estimated dividend yield and growth rates of her proxy group (Exh. AG-JRW-1, at 40). The Attorney General calculated the DCF dividend yield for the proxy group using the current annual dividend and the 30-day, 90-day, and 180-day average stock prices based on data supplied by Yahoo! Inc. (Exhs. AG-JRW-1, at 31; JRW-10, at 2). The median dividend yields for the Attorney General's proxy group using this method range from 3.40 percent to 3.70 percent (Exhs. AG-JRW-1, at 31; JRW-10, at 2). Within this range, the Attorney General chose 3.55 percent as the dividend yield for the gas proxy group (Exhs. AG-JRW-1, at 31; JRW-10, at 2).

The dividend yield is obtained by dividing the annualized expected dividend in the coming quarter by the current stock price (Exh. AG-JRW-1, at 31). To annualize the expected dividend, the Attorney General multiplied the expected dividend for the coming quarter by four and multiplied the result by one-half of the expected growth rate (Exh. AG-JRW-1, at 31-32).

In developing the expected growth rate, the Attorney General relies on the historic and projected growth rates of earnings per share, dividends per share, and book value per share provided by Value Line and the EPS growth forecasts of Wall Street analysts provided by Yahoo! Inc., Reuters and Zacks (Exh. AG-JRW-1, at 32). Although the Attorney General assumes that earnings per share and dividends per share will exhibit similar growth rates over the very long term, she relies on dividends per share and book value per share to balance what she states are the shortcomings of relying solely on earnings per share as a proxy (i.e., an upward bias among Wall Street securities analysts) (Exh. AG-JRW-1, at 36). The DCF growth rate for the proxy group used in the Attorney General's analysis is five percent (Exhs. AG-JRW-1, at 39; JRW-10, at 1).

The Attorney General added the adjusted dividend yield and the estimated growth rate to determine a cost of equity for the proxy group (Exhs. AG-JRW-1, at 40; JRW-10, at 1). The DCF analysis performed by the Attorney General yields a cost of equity of 8.65 percent (Exhs. AG-JRW-1, at 40; JRW-10, at 1).

c. Positions of the Parties

i. Attorney General

The Attorney General argues that her DCF-estimated cost of equity of 8.65 percent (based on a 3.55 percent growth adjusted dividend yield and a five percent growth rate) appropriately supports her proposed ROE for NSTAR Gas (see Attorney General Brief at 38, 48-49, 62, citing Exh. AG-JRW-1, at 1, at 39-40). The Attorney General maintains that her model incorporates a growth rate that is not overly reliant on the earnings per share forecasts of Wall Street analysts that she argues are "overly optimistic and upwardly biased" (Attorney General Brief at 48-49, citing Exhs. AG-JRW-1, at 39-40; JRW-1, at App. B).

Alternately, the Attorney General argues that the Department should reject the DCF analysis that supports the Company's proposed ROE for several reasons. First, the Attorney General argues that the Company's analysis ignores the mean low DCF results for the constant-growth DCF model applications (Attorney General Brief at 50, citing Exhs. NSTAR-RBH-1, at 15-29; NSTAR-RBH-3). In this regard, the Attorney General contends that the Company eliminated DCF results for proxy group companies that had low equity cost rates, while retaining those cost rates that were high-end outliers (Attorney General

Brief at 50, citing Exh. AG-JRW-1, at 55). According to the Attorney General, by eliminating only the so-called low-end outliers, the Company biases its DCF equity cost rate study and reports a higher DCF equity cost rate than the data indicate (Attorney General Brief at 50, citing Exh. AG-JRW-1, at 55).

Second, the Attorney General contends that the Company relies exclusively on the earnings per share growth forecasts of Wall Street analysts and Value Line (Attorney General Brief at 50). The Attorney General asserts that there is ample empirical evidence to support her claim that such forecasts are upwardly biased[215] (Attorney General Brief at 50, citing Exh. AG-JRW-1, at App. B).

Third, the Attorney General asserts that the Company's GDP growth rate of 5.64 percent in its multi-stage DCF model is excessive, is unsupported by theoretical or empirical evidence, is not reflective of economic growth in the United States, and is about 100 basis points above projections of long-term GDP growth (Attorney General Brief at 50, citing Exh. AG-JRW-14). The Attorney General claims that despite some fluctuations, nominal GDP growth rates have declined over the years and have been in the 3.50 to four percent range over the five years leading up to 2015[216] (Attorney General Brief at 52, citing Exh. AG-JRW-1, at 57). The

215 For example, the Attorney General cites a 2010 study that states "analysts have been persistently over optimistic for the past 25 years, with estimates ranging from [ten] to 12 percent a year, compared with actual earnings growth of six percent. . . . On average, analysts' forecasts have been almost 100 percent too high" (Attorney General Brief at 50-51, citing Exh. AG-JRW-1, App. B).

216 The Attorney General maintains that nominal GDP has grown at a compounded rate of 6.63 percent since 1960, and grew from six percent to over twelve percent from the 1960s to the early 1980s due largely to inflation and higher prices (Attorney General Brief at 52, citing Exh. AG-JRW-14, at 2). The Attorney General adds that with the exception of an uptick during the mid-2000s, economic growth in the United States has slowed

Attorney General contends that the compounded GDP growth rate of 6.63 percent over the 50 years since the mid-1960s belies a monotonic and significant decline in nominal GDP growth rates in recent decades (Attorney General Brief at 52, citing Exh. AG-JRW-1, at 58). Therefore, the Attorney General concludes that a more appropriate nominal GDP growth rate figure for today's economy is in the range of four to five percent (Attorney General Brief at 52-53, citing Exhs. AG-JRW-1, at 57; JRW-14, at 3-4).

Finally, the Attorney General argues that the Company's DCF analyses are inconsistent in their use of historic versus projected data (Attorney General Brief at 54, citing Exh. AG-JRW-1, at 59-60). In particular, the Attorney General notes that in developing a DCF growth rate for its constant-growth DCF analysis, the Company ignored historical earnings per share, dividends per share, book value per share data, and relied solely on inflated long-term earnings per share growth rate projections (Attorney General Brief at 54, citing Exh. AG-JRW-1, at 59-60). In addition, the Attorney General asserts that the Company ignored well-known, long-term real GDP growth rate forecasts of the Congressional Budget Office and Energy Information Administration in developing a terminal DCF growth rate for its multi-stage growth DCF analysis (Attorney General Brief at 54, citing Exh. AG-JRW-1, at 59-60). Instead, the Attorney General contends, the Company relied solely on historic data dating back to 1929 (Attorney General Brief at 54, citing Exh. AG-JRW-1, at 59-60).

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considerably in recent decades, with nominal GDP growth rates declining due to lower real GDP growth and lower inflation (Attorney General Brief at 52, citing Exhs. AG-JRW-1, at 57; AG-JRW-14, at 3-4).

ii. Company

NSTAR Gas argues that the Attorney General's DCF calculation that results in an 8.65 percent cost of equity is subjective and incapable of replication (Company Brief at 165, citing Exh. NSTAR-RBH-Rebuttal-1, at 26; Company Reply Brief at 7). In particular, the Company contends that it is unclear how the Attorney General developed her proposed growth rate of five percent except (Company Brief at 165). Nonetheless, the Company maintains that the Attorney General excluded consideration of analysts' growth rate projections, which the Company argues is the equivalent of excluding the market's judgment (Company Brief at 165, citing Exh. NSTAR-RBH-Rebuttal-1, at 26; Company Reply Brief at 6). In addition, the Company asserts that Attorney General's DCF recommendation improperly relies on dividend per share and book value per share growth rates, which it contends are merely derivative of earnings growth (Company Brief at 165, citing Exh. NSTAR-RBH-Rebuttal-1, at 25-26). According to the Attorney General, the Department has been critical of the role that dividend per share growth rates play in the DCF calculation (Company Brief at 165, citing D.P.U. 10-114 at 312).

The Company disputes that it ignored low DCF results as suggested by the Attorney General (Company Brief at 166). Instead, the Company claims that its DCF calculation includes the average of all consensus earnings per share results in its mean DCF results, including low growth projections[217] (Company Brief at 166, citing Exh. RBH-1-Rebuttal-1, at 20).

[217] The Company notes that the Attorney General initially asserted that the Company excluded the low DCF results, but later claimed that the Company minimized the low results (Company Brief at 166 at n.31).

In addition, NSTAR Gas dismisses the Attorney General's contention that the earnings per share growth rate estimates relied on by the Company were biased (Company Brief at 166). First, the Company maintains that the Attorney General gave "primary weight" to analysts' forecasts even though she considers them biased (Company Reply Brief at 6). Second, the Company asserts that litigation and new financial regulations in the early 2000s helped neutralize analysts' conflicts of interest while removing bias in the median forecast errors (Company Brief at 166, citing Exh. NSTAR-RBH-Rebuttal-1, at 21-23). Third, the Company contends that the notion that forecasts of Wall Street analysts are upwardly biased has not been proven in the context of gas utilities (Company Brief at 166, citing Exh. NSTAR-RBH-Rebuttal-1, at 24-25). The Company maintains that regardless of analysts' forecasts, it is investor expectations that matter when applying the DCF model and the DCF-estimated ROE must recognize and reflect that it is the earnings per share growth rate expectations of investors that drive stock prices, even if influenced by analysts' forecasts (Company Brief at 167, citing Exh. NSTAR-RBH-Rebuttal-1, at 23).

Next, NSTAR Gas disagrees with the Attorney General's claim that the Company's multi-stage DCF model does not appropriately reflect more recent lower GDP growth (Company Brief at 167). The Company argues that: (1) since 1990, the annual nominal growth rate in GDP has remained relatively stable; and (2) in twelve of the last 25 years, the annual nominal growth rate in GDP was greater than five percent (Company Brief at 167, citing Exh. NSTAR-RBH-Rebuttal-1, at 29). Further, the Company maintains that because of the 2008 through 2012 recession, it is inappropriate to calculate the real GDP growth rate over short periods (Company Brief at 167, citing Exh. NSTAR-RBH-Rebuttal-1, at 30). Further, the

Company contends that the Congressional Budget Office's GDP growth rate forecast is irrelevant because it applies to the 2015 to 2025 period, and the DCF multi-stage model begins in 2025 (Company Brief at 167, citing Exh. NSTAR-RBH-Rebuttal-1, at 32).

Finally, NSTAR Gas takes issue with the Attorney General's attempt to reproduce the Company's multi-stage DCF method using a lower terminal GDP growth rate of 4.45 percent (Company Reply Brief at 7-8, citing Attorney General Reply Brief at 30, citing Exh. AG-JRW-Rebuttal at 10-11; see, Exh. NSTAR-RBH-1, at 6, Table 1). According to the Company, the Attorney General violates a fundamental assumption of the DCF model by failing to hold the price-to-earnings ratio constant[218] (Company Reply Brief at 8-9, citing Attorney General Reply Brief at 29-30; Exh. NSTAR-RBH-Rebuttal-1, at 17-19; Tr. 8, at 704-705; Tr. 11, at 917-920).

d. Analysis and Findings

In developing their proposed ROEs, both the Company and the Attorney General use a form of the DCF model that assumes an infinite investment horizon and a constant growth rate (Exhs. NSTAR-RBH-1, at 18; AG-JRW-1, at 29). This model has a number of very strict assumptions (e.g., the infinite investment horizon and dividend growth at a constant rate in perpetuity) (Exh. NSTAR-RBH-1, at 18, n.10). These assumptions affect the estimates of the cost of equity. D.P.U. 10-114, at 312; D.P.U. 09-39, at 387.

218 The Company maintains that the fundamental assumption of a DCF analysis is that there is a constant and infinite expected growth rate, and constant dividend-to-earnings and price-to-earnings ratios (Company Reply Brief at 8, citing Tr. 11, at 917-918). The Company contends that by altering the terminal GDP growth rate, the Attorney General did not hold the price-to-earnings ratio constant in her analysis and this error resulted in lower summary multi-stage DCF results (Company Reply Brief at 8, citing Tr. 11, at 919, 920, 925).

Because regulation establishes a level of authorized earnings for a utility that, in turn, implicitly influences dividends per share, estimation of the growth rate from such data is an inherently circular process. D.P.U. 10-114, at 312; D.P.U. 10-55, at 512; D.P.U. 09-30, at 357-358. In addition, the DCF model includes an element of circularity when applied in a rate case because investors' expectations depend upon regulatory decisions. D.P.U. 10-70, at 253; D.P.U. 09-30, at 357-358. Consequently, this circularity affects the reliability of both the Company's and the Attorney General's DCF models. The Attorney General's DCF model places less emphasis on analyst forecasts of earnings per share growth rates which, to some extent, compensates for this circularity (see Exh. AG-JRW-1, at 36-40).

The Company and Attorney General use different data sources to estimate the dividend yield and growth rates (Exhs. NSTAR-RBH-1, at 17-23; AG-JRW-1, at 30-40). The Company uses the Bloomberg Professional estimates, adjusting them by one-half of the growth rate, while the Attorney General calculates the dividend yield by applying one-half of the growth rate to a six-month average dividend yield (Exhs. NSTAR-RBH-1, at 17-23; NSTAR-RBH-Rebuttal-2; NSTAR-RBH-Rebuttal-4; AG-JRW-1, at 32; AG-JRW-10). The Department finds that both the Company's and the Attorney General's approaches are logical and reasonable. Further, there is no evidence to establish that investors rely overwhelmingly on one approach over the other. Therefore, we find that both approaches provide a credible basis for evaluating a determination of the Company's allowed ROE.

In addition, the Company and the Attorney General use different growth rates in their respective DCF analyses (Exhs. NSTAR-RBH-1, at 18-20; NSTAR-RBH-Rebuttal-2; NSTAR-RBH-Rebuttal-4; AG-JRW-1, at 32; AG-JRW-10). Determining the appropriate long-term growth expectations of investors in a DCF analysis can be difficult and controversial (Exhs. NSTAR-RBH-1, at 18; AG-JRW-1, at 29-30, 32). The Company relies on a forward-looking growth analysis using earnings per share, based on the assumption that investors form their investment decisions based on expectations of growth in earnings and not dividends (Exhs. NSTAR-RBH-1, at 20-21; NSTAR-RBH-Rebuttal-2; NSTAR-RBH-Rebuttal-4). The Attorney General bases her growth rate on a historical and forward-looking growth analysis using earnings per share, dividends per share, book value per share, and retention growth rates (Exhs. AG-JRW-1, at 32-33). The Attorney General emphasizes dividend growth with less reliance on earnings per share because of the alleged upward bias of forecasts by financial analysts (Exhs. AG-JRW-1, at 32-34 & App. B; JRW-10, at 3, 4, 5). The Department has found that investors' heavy reliance on earnings per share forecasts gives credit to the Attorney General's argument that investors are aware of upward biases. D.P.U. 13-75, at 302. Accordingly, the Department will take these biases into consideration in evaluating the Company's DCF analysis.

Because regulation establishes a level of allowed earnings, which, in turn, implicitly influences earnings per share, dividends per share, and book value per share, estimation of the growth rate from such data is an inherently circular process. See Charles F. Phillips, Jr., The Regulation of Public Utilities – Theory and Practice, Public Utility Reports, Inc., 1993, at 396, 398. Accordingly, the Department considers this limitation in evaluating the DCF cost of equity estimates.

An additional disagreement between the Company and the Attorney General concerns the Company's weighting of low-end DCF results (Exhs. NSTAR-RBH-1, at 23; AG-JRW-1, at 54-55). The Department has found that, to some extent, errors in the DCF model's assumptions are responsible for DCF cost of equity anomalies. D.P.U. 13-90, at 219; D.P.U. 13-75, at 303. Moreover, the elimination of outliers will reduce the amount of data in a sample set and, consequently may affect the statistical reliability of the results. D.P.U. 13-75, at 303. Because of the limitations of these models, the Department has found that it is appropriate to consider all DCF estimates when evaluating a company's ROE. D.P.U. 13-90, at 219; D.P.U. 13-75, at 303. Here, we find that by minimizing the results of the outliers, the Company's DCF analysis overestimates the required ROE.

5. Capital Asset Pricing Model

a. Company's Proposal

The Company used the CAPM to estimate the cost of equity for its proxy group (Exh. NSTAR-RBH-1, at 29). The application of the Company's CAPM resulted in eight individual cost of equity estimates, ranging from 10.09 percent to 11.44 percent (Exhs. NSTAR-RBH-1, at 32, 50; NSTAR-RBH-Rebuttal-1, at 60; NSTAR-RBH-Rebuttal-7).

The CAPM is a market-based investment model based on capital markets theory and modern portfolio theory. In the CAPM, the required rate of return is equal to the expected risk-free rate of return plus a premium for the implicit systematic risk of the security (Exh. NSTAR-RBH-1, at 29). There are three necessary components to calculate the cost of equity in the CAPM: (1) an expected risk-free rate of return; (2) the market risk premium; and (3) the beta, a measure of systematic risk (Exhs. NSTAR-RBH-1, at 29; NSTAR-RBH-Rebuttal-1, at 60; NSTAR-RBH-Rebuttal-7).

The Company used the current and forecasted 30-year Treasury bond yields to arrive at current, near-term, and long-term risk-free rates (Exhs. NSTAR-RBH-1, at 30; NSTAR-RBH-Rebuttal-1, at 60; NSTAR-RBH-Rebuttal-7). The CAPM market risk premium is derived from the total return on the overall market minus the risk-free rate of return. The Company developed ex-ante market risk premiums based on data from both Bloomberg and Value Line by calculating their respective estimated market required returns less the Treasury bond yield[219] (Exhs. NSTAR-RBH-1, at 31; NSTAR-RBH-Rebuttal-1, at 60; NSTAR-RBH-Rebuttal-5; NSTAR-RBH-Rebuttal-7). The Company obtained beta coefficients for its proxy group from Bloomberg (i.e., 0.735) and Value Line (i.e., 0.79) (Exhs. NSTAR-RBH-Rebuttal-1, at 60; NSTAR-RBH-Rebuttal-7; NSTAR-RBH-Rebuttal-6).

Using these beta coefficients in combination with separate Bloomberg and Value Line data and current, near-term, and long-term risk-free rates, NSTAR Gas calculated four Bloomberg market DCF-derived CAPM results and four Value Line market DCF-derived CAPM results (Exhs. NSTAR-RBH-1, at 31-32; NSTAR-RBH-Rebuttal-1, at 60; NSTAR-RBH-Rebuttal-7).

b. Attorney General's Proposal

The Attorney General used a traditional CAPM approach in which the cost of equity is equal to the sum of the interest rate on risk-free bonds and an equity risk premium (i.e., the excess return that an investor expects to receive above the risk-free rate for investing in stocks)

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219 In the Company's CAPM, the estimated market required return is based on a market capitalization-weighted average DCF result, which consists of an expected dividend yield combined with the market capitalization-weighted projected earnings growth rate (Exhs. NSTAR-RBH-1, at 31; NSTAR-RBH-Rebuttal-5).

(Exh. AG-JRW-1, at 40-41). The Attorney General's CAPM analysis resulted in a cost of equity of 8.4 percent (Exh. AG-JRW-1, at 46-49).

In her analysis, the Attorney General used the upper bound of the six-month average yield on 30-year Treasury bonds (i.e., four percent) as the risk-free rate (Exh. AG-JRW-1, at 42). The Attorney General then calculated an estimated market risk premium of 5.5 percent, based on the midpoint of a range of market risk premiums of four to six percent (Exhs. AG-JRW-1, at 48; JRW-11, at 1, 5-6). To calculate the beta coefficient, the Attorney General performed a regression analysis of the returns of the companies in her proxy group against the return of the S&P 500 representing the market, resulting in a median beta coefficient of 0.80 percent (Exhs. AG-JRW-1 at 42-43; JRW-11, at 3). The Attorney General multiplied the estimated market risk premium of 5.5 percent by the beta coefficient of 0.80 percent to produce an expected equity risk premium of 4.4 percent (Exhs. AG- JRW-1 at 49; JRW-11, at 1). When the risk-free rate of four percent is added to the expected risk premium of 4.4 percent, the result is a cost of equity of 8.4 percent (Exhs. AG- JRW-1 at 49; JRW-11, at 1).

c. Positions of the Parties

i. Attorney General

The Attorney General argues that the Company's CAPM analysis produces results that vastly overstate long-term growth projections (Attorney General Brief at 58). According to the Attorney General, the Company's primary errors are with its use of inflated market risk premiums of 10.31 percent and 9.65 percent[220] (Attorney General Brief at 57,

[220] The Attorney General refers to the market risk premium figures and long-term earnings per share growth rates from the Company's initial filing and not those in the CAPM

citing Exh. AG-JRW-1, at 61). Further, the Attorney General contends that the Company's long-term earnings per share growth rates of 13.91 percent and 12.74 percent reflect those overly optimistic and upwardly biased Wall Street analysts' forecasts (Attorney General Brief at 57, citing Exh. AG-JRW-1, at 61).

In contrast, the Attorney General maintains that long-term economic, earnings, and dividend growth rates in the United States indicate that historical long-term growth rates are in the five to seven percent range[221] (Attorney General Brief at 58, citing Exhs. AG-JRW-1, at 62-63; JRW-14). Moreover, the Attorney General asserts that more recent trends suggest lower future economic growth than the long-term historic GDP growth, in the range of four to five percent for today's economy and 4.5 percent to 4.8 percent for projected long-term GDP growth rate forecasts (Attorney General Brief at 58, citing Exhs. AG-JRW-1, at 63-64; JRW-14).

Finally, the Attorney General argues that given current low inflation and limited economic growth, the Company's projected earnings growth rates, implied expected stock market returns, and equity risk premiums are not indicative of the realities of the economy (Attorney General Brief at 58-59, citing Exh. AG-JRW-1, at 64-65). Based on the above, the Attorney General argues that the Department should reject the Company's proposed CAPM analysis and recommendations (Attorney General Brief at 60).

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update provided by the Company on May 20, 2015 (Attorney General Brief at 57-58, citing Exh. AG-JRW-1 at 61).

221 The Attorney General evaluated the growth in nominal GDP, S&P 500 stock price appreciation, and S&P 500 earnings per share and dividends per share growth since 1960 (Attorney General Brief at 58, citing Exhs. AG-JRW-1, at 62-63; JRW-14).

ii. Company

The Company argues that the Attorney General's CAPM calculation must be rejected because the equity risk premium she relied upon assumes market returns that do not make theoretical or practical sense (Company Brief at 167, citing Exh. NSTAR-RBH-Rebuttal-1 at 36). Further, the Company contends that the Attorney General's CAPM analyses seem contradictory and do not reflect fundamental risk-return relationships (Company Brief at 168, citing Exh. NSTAR-RBH-Rebuttal-1 at 37). For example, the Company maintains that depending upon the analysis used by the Attorney General, the expected market return is either approximately nine percent or 7.25 percent (Company Brief at 167-168, citing Exh. NSTAR-RBH-Rebuttal-1 at 36-37). In addition, the Company argues that the Attorney General's development of a market risk premium is based on two questionable surveys (Company Brief at 168, citing Exh. NSTAR-RBH-Rebuttal-1 at 34).

Finally, the Company dismisses the Attorney General's claim that reliance on analysts' forecasts invalidates the Company's CAPM approach (Company Brief at 168). Like its arguments above regarding the DCF model, the Company maintains that recent evidence does not support any upward bias in analysts' forecasts (Company Brief at 168, citing Exh. NSTAR-RBH-Rebuttal-1 at 34).

d. Analysis and Findings

The Department has previously found that the traditional CAPM as a basis for determining a utility's cost of equity has limited value because of a number of questionable assumptions that underlie the model.[222] See D.P.U. 10-114, at 318; D.P.U. 10-70, at 270; D.P.U. 08-35, at 207; 138 D.T.E. 03-40, at 359-360; Commonwealth Electric Company, D.P.U. 956, at 54 (1982). For example, the Department has not been persuaded that long-term government bonds are the appropriate proxy for the risk-free rate and has found that the coefficient of determination for beta is generally so low that the statistical reliability of the results is questionable. D.T.E. 01-56, at 113; D.P.U. 93-60, at 256-257; D.P.U. 92-78, at 113; D.P.U. 88-67 (Phase I) at 182-184.

The Attorney General's CAPM analysis employs a risk-free rate of four percent, using the upper bound of the prior six months' 30-year Treasury bond rates as a proxy (Exh. AG-JRW-1, at 49). Current federal monetary policy that is intended to stimulate the economy has pushed treasury yields to near-historic lows (Exh. AG-JRW-1, at 14). Consequently, the Department has found that a CAPM analysis based on current treasury yields may tend to underestimate the risk-free rate over the long term and, thereby, understate the required ROE. See D.P.U. 12-25, at 427; D.P.U. 11-01/D.P.U. 11-02, at 416.

The Company develops a range of risk-free rates from 2.57 percent to 3.20 percent, relying on the current 30-year Treasury bond rates, as well as the near- and long-term projected 30-year Treasury bond rates based on interest rate forecasts from Blue Chip Financial

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[222] In D.P.U. 08-35, at 207 n.131, the Department identified the following questionable assumptions used in the CAPM: (1) capital markets are perfect with no transaction costs, taxes, or impediments to trading, all assets are perfectly marketable, and no one trader is significant enough to influence price; (2) there are no restrictions to short-selling securities; (3) investors can lend or borrow funds at the risk-free rate; (4) investors have homogeneous expectations (i.e., investors possess similar beliefs on the expected returns and risks of securities); (5) investors construct portfolios on the basis of the expected return and variance of return only, implying that security returns are normally distributed; and (6) investors maximize the expected utility of the terminal value of their investment at the end of one period.

(Exhs. NSTAR-RBH-Rebuttal-1 at 59; NSTAR-RBH-Rebuttal-7). The CAPM is based on investor expectations and, therefore, it is appropriate to use a prospective measure for the risk-free rate component. The Department has found that the Blue Chip Financial estimate is widely relied on by investors and provides a useful proxy for investor expectations for the risk-free rate. D.P.U. 13-75, at 314.

The Attorney General calculated a market risk premium of 5.5 percent, based on her analysis of numerous surveys of financial professionals, including financial forecasters, chief financial officers, and academics (Exhs. AG-JRW-1, at 48-49; AG-JRW-11, at 1). Alternatively, the Company calculates a market risk premium range of 10.09 percent to 11.44 percent based on DCF analyses (Exhs. NSTAR-RBH-Rebuttal-1 at 59; NSTAR-RBH-Rebuttal-7). Because the CAPM is considered an ex-ante, forward-looking model which recognizes that investors are generally risk averse and will demand higher returns in exchange for assuming higher levels of investment risk, the Department finds the Company's approach is less reliable than the survey results of financial professionals. D.P.U. 13-90, at 225-226; D.P.U. 13-75, at 314.

The Company asserts that investors rely on financial analysts' forecasts in making investment decisions and, therefore, earnings per share forecasts are superior to other measures of growth in predicting stock prices (see Exh. NSTAR-RBH-1, at 19-20). The Department notes that a 2014 survey of over 8,000 academics, financial analysts, and companies estimates a market risk premium of five percent, which is far lower than the 10.09 percent to 11.44 percent range used in the Company's analysis[223] (Exhs. NSTAR-RBH-Rebuttal-1 at 59;

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[223] See Pablo Fernandez, Pablo Linares, and Isabel Fernandez Acin, "Market Risk Premium Used for 88 Countries in 2014: a Survey with 8,288 Answers" (June 20, 2014).

NSTAR-RBH-Rebuttal-7; AG-JRW-1, at 48-49; AG-JRW-11, at 1). Accordingly, the Department places more weight on the Attorney General's approach to developing a market risk premium.

Based on the above considerations, the Department will place limited weight on the results of the respective CAPM estimates in determining the appropriate ROE. To the limited extent that we rely on CAPM estimates, the Department gives more weight to the Attorney General's proposed CAPM because the magnitude of the deficiencies in Company's proposed CAPM is greater.

6. Risk Premium Model

a. Company's Proposal

The risk premium model is based on the concept that investing in common stock is riskier than investing in debt and, therefore, investors require a higher rate of return for equity[224] (Exh. NSTAR-RBH-1, at 32-33). In the bond yield plus risk premium model used by the Company, the cost of equity is derived by calculating a risk premium over the returns available to bondholders (Exh. NSTA-RBH-1, at 33-35). The Company's risk premium analysis produced a cost of equity range of 10.03 percent to 10.55 percent (Exhs. NSTAR-RBH-Rebuttal-1 at 60; NSTAR-RBH-Rebuttal-8).

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[224] The equity risk premium is defined as the incremental return that an equity investment provides over the risk-free rate (Exh. NSTAR-RBH-1, at 33 & n.24). The risk premium method of determining the cost of equity recognizes that common equity capital is more risky than debt from an investor's standpoint, and that investors require higher returns on stocks than on bonds to compensate for the additional risk. The general approach is relatively straightforward: (1) determine the historical spread between the return on debt and the ROE; and (2) add this spread to the current debt yield to derive an estimate of current equity return requirements. D.P.U. 13-75, at 316 n.201.

NSTAR Gas calculated the risk premium as the difference between (1) actual authorized returns for natural gas utilities using data from 1,007 gas utility rate proceedings between January 1, 1980 and October 31, 2014, and (2) the then-prevailing long-term (i.e., 30-year) Treasury yield (Exh. NSTAR-RBH-1, at 33). To account for the forward-looking return and interest rates, NSTAR Gas calculated the average return period between the filing of this case and the approval of rates, as well as the level of interest rates during the pendency of the proceedings (i.e., the average 30-year Treasury yield) (Exh. NSTAR-RBH-1, at 33). To assess the relationship between the 30-year Treasury yield and the equity risk premium, the Company relied on a statistical analysis that concluded there was a statistically significant inverse relationship between the 30-year Treasury yield and the equity risk premium (Exhs. NSTAR-RBH-1, at 34-35; NSTAR-RBH-Rebuttal-8).

b. Positions of the Parties

i. Attorney General

The Attorney General asserts that the Company's application of the bond yield plus risk premium model is flawed for three reasons (Attorney General Brief at 60-61). First, the Attorney General argues that the Company's method produces an inflated measure of the risk premium because it is based on historic authorized ROEs less Treasury yields, and then is applied to projected Treasury yields that are always forecasted to increase (Attorney General Brief at 60, citing Exh. AG-JRW-1, at 67). Second, the Attorney General argues that the Company's overall approach improperly uses authorized ROEs as an input to the model; such an approach is more of a gauge of commission behavior than a consideration of investor behavior (Attorney General Brief at 60-61, citing Exh. AG-JRW-1, at 67-68). In this regard, the Attorney

General contends that in setting ROEs, regulatory commissions evaluate capital market data such as dividend yields, expected growth rates, interest rates, as well as rate-case-specific regulatory information (Attorney General Brief at 60-61, citing Exh. AG-JRW-1, at 67-68). Further, the Attorney General argues that the Company's analysis overstates the risk premium because the Company estimates the risk premium using historical interest rate data, and then applies this data to forecasted interest rates (Attorney General Brief at 61, citing Exh. AG-JRW-1, at 67).

Finally, the Attorney General contends that a comparison of the Company's risk premium results to actual authorized ROEs for gas companies confirms the errors in the Company's approach (Attorney General Brief at 61, citing Exh. AG-JRW-1, at 67). The Attorney General notes that authorized ROEs for gas distribution companies have decreased in recent years, from 9.94 percent in 2012, to 9.68 percent in 2013, to 9.78 percent in 2014 (Attorney General Brief at 61, citing Exh. AG-JRW-Rebuttal, at 12). Finally, the Attorney General claims that NSTAR Gas' long-term projected Treasury bond yield of 5.45 percent is 250 basis points above current yields and, therefore, is not reasonable (Attorney General Brief at 60, citing Exh. AG-JRW-1, at 67).

ii. Company

NSTAR Gas disputes the Attorney General's argument that the Company's bond yield plus risk premium approach gauges regulatory commission behavior rather than investor behavior (Company Brief at 168). The Company argues that regulatory decisions reflect market-based analyses (Company Brief at 169, citing Exh. NSTAR-RBH-Rebuttal-1, at 41). Further, the Company maintains that because authorized returns are publicly available, such data are to some degree reflected in investors' return expectations and requirements. For these reasons, the Company argues that authorized returns are a reasonable measure of investor-required returns (Company Brief at 169, citing Exh. NSTAR-RBH-Rebuttal-1, at 41). Finally, the Company maintains that the Department has viewed the risk premium approach as a "supplemental approach" in determining an ROE and it has used it in that manner here (Company Brief at 169, citing D.P.U. 07-71, at 137).

c. Analysis and Findings

The Department has repeatedly found that an equity risk premium analysis can overstate the amount of company-specific risk and, therefore, the cost of equity. See D.P.U. 10-114, at 322; D.P.U. 10-70, at 269; D.P.U. 88-67 (Phase I) at 182-184. More specifically, the Department has found that the return on long-term corporate or public utility bonds may have risks that could be diversified with the addition of common stock in investors' portfolios and, therefore, that the risk premium model overstates the risk accounted for in the resulting cost of equity. D.P.U. 10-114, at 322; D.P.U. 10-70, at 269; D.P.U. 90-121, at 171; D.P.U. 88-67 (Phase I) at 182-183. Nonetheless, the Department has acknowledged the value of the risk premium model as a supplemental approach to other ROE models. D.P.U. 10-114, at 322; D.P.U. 10-70, at 269; D.P.U. 07-71, at 137; D.T.E. 99-118, at 85-86.

In the instant case, the Company's risk premium analysis is flawed. First, the Department has recognized the circularity inherent in the use of authorized utility returns to derive the risk premium. D.P.U. 13-75, at 319; D.P.U. 90-121, at 171; D.P.U. 88-67 (Phase I) at 182-183. In addition, the Department has criticized the use of corporate bond yields in determining the base component of the risk premium analysis and we are not convinced that the Company's substitution of projected Treasury debt yields is a better approach. D.P.U. 09-39, at 388-389; D.P.U. 08-35, at 202; D.P.U. 90-121, at 171. The Company suggests that that the risk premium approach is forward-looking and, therefore, using the projected cost of Treasury debt in this model is appropriate (Company Brief at 146). The Department disagrees. The risk premium model is not a forward-looking approach, and is instead based on current market conditions. See D.P.U. 13-75, at 319; D.P.U. 12-25, at 433. Accordingly, the Department finds that current treasury yields are more appropriate than projected yields for use in a risk premium analysis. For these reasons, the Department finds that NSTAR Gas' bond yield plus risk premium model overstates the required ROE for the Company.

7. Flotation Costs

a. Company's Proposal

The Company factors flotation costs into its proposed ROE, asserting that such costs must be considered part of capital costs that are properly reflected on the balance sheet under "paid in capital" rather than current expenses (Exh. NSTAR-RBH-1, at 39-40). The Company used the equity issuing costs incurred in the two most recent issuances for the Company and its proxy group to develop a floatation cost estimate of 0.12 percent (Exh. NSTAR-RBH-1, at 40). The Company maintains, however, that it did not simply increase its proposed ROE by twelve basis points to reflect the effect of the flotation costs. Instead, the Company states that it considered the effect of floatation costs in addition to other business risks when determining the appropriate ROE within the range of results produced by the various cost of equity models (Exh. NSTAR-RBH-1, at 40).

b. Positions of the Parties

i. Attorney General

The Attorney General argues that the Department has consistently rejected inclusion of flotation costs in the cost of service because investors already consider issuance costs in their decision to purchase the stock at a given price (Attorney General Brief at 62, citing D.P.U. 90-121, at 180; D.P.U. 88-67 (Phase I) at 193; D.P.U. 86-280-A at 112; D.P.U. 85-137, at 100). Moreover, the Attorney General contends that utilities that are part of a holding company structure do not have flotation costs and only negligible issuance costs, because all stock is issued to the parent company (Attorney General Brief at 62, citing D.P.U. 800, at 51; Western Massachusetts Electric Company, D.P.U. 20279, at 37 (1980); Massachusetts Electric Company, D.P.U. 19376, at 7-13 (1979)).

ii. Company

The Company argues that flotation costs for stock issuances are no different than issuance costs associated with long-term debt because companies pay the same types of fees regardless of whether they are issuing equity or debt (Company Brief at 169, citing Exh. NSTAR-RBH-Rebuttal-1, at 51). Nevertheless, the Company emphasizes that it did not make a specific flotation adjustment to its proposed ROE, but only considered the effect of flotation costs in combination with other factors determining the appropriate ROE (Company Brief at 169, citing Exh. NSTAR-RBH-1, at 40; Tr. 8, at 692).

c. Analysis and Findings

NSTAR Gas asserts that it is appropriate to consider flotation costs in determining its allowed ROE because Northeast Utilities and companies in its proxy group will incur such costs when issuing equity (Exhs. NSTAR-Rebuttal-1, at 52; NSTAR-RBH-1, at 40). The Department has rejected issuance cost adjustments for the purpose of determining ROE. D.P.U. 90-121, at 180; D.P.U. 88-67 (Phase I) at 193; D.P.U. 86-280-A at 112; D.P.U. 85-137, at 100. The Company has not persuaded us to depart from our precedent here.

The Company's proposal to weigh flotation costs when establishing its ROE relies on issuance costs that investors are well aware of when they enter the market for publicly traded stocks. Therefore, its proposal suffers from the same defects that the Department has previously identified, namely the double-counting of flotation costs. D.P.U. 10-70, at 259; D.P.U. 88-67 (Phase I) at 193; D.P.U. 85-137, at 100.

The Department allows companies to recover issuance costs associated with common stock by amortizing those costs over a period of time. USOA-Gas, Income Accounts, Miscellaneous Income Deductions, Account 425. NSTAR Gas, however, is a wholly owned subsidiary of Northeast Utilities and, therefore, has no publicly-traded stock on which to incur flotation costs[225] (Exh. NSTAR-WJA-1, at 14). For these reasons, the Department will not take flotation costs into consideration when determining the Company's required ROE.

8. Cost of Equity Impact of Decoupling and GSEP

a. Positions of the Parties

i. Attorney General

The Attorney General argues that the Department should reduce the Company's allowed ROE to compensate for the impact of decoupling in lowering the Company's risk

225 The Company's last stock issue was approved in Commonwealth Gas Company, D.P.U. 97-50 (1997). The Company's equity needs are currently being met by capital contributions from Northeast Utilities (Exh. NSTAR-Rebuttal-1, at 14).

(Attorney General Brief at 63, citing AG-JRW-1, at 70). In support of her position, the Attorney General contends that the decreased risk associated with decoupling is not reflected in the stock prices of all of the companies in NSTAR Gas' proxy group (Attorney General Brief at 63, citing AG-JRW-1, at 70). The Attorney General notes that the Company's proxy group includes companies that operate non-utility segments associated with unregulated activities and, therefore, are riskier than regulated gas utility operations (Attorney General Brief at 63, citing AG-JRW-1, at 69-70). Further, she notes that only 67 percent of Company's proxy group revenues come from regulated gas operations (Attorney General Brief at 63, citing AG-JRW-1, at 69-70). Thus, the Attorney General asserts that a significant portion of the revenues of the Company's proxy group are not subject to revenue stabilization mechanisms like decoupling (Attorney General Brief at 63, citing AG-JRW-1, at 70). According to the Attorney General, the Company's proposed ROE does not appropriately consider the impact of unregulated revenues on the riskiness of the companies in its proxy group (Attorney General Brief at 63, citing AG-JRW-1, at 69-70).

ii. Company

NSTAR Gas contends that because revenue decoupling and infrastructure investment mechanisms like the GSEP are common among the companies in its proxy group, there is no reason to assume that the Company is materially less risky than its peers or that its ROE should be lower due to decoupling or its GSEP (Company Brief at 148-149, 170, citing Exhs. NSTAR-RBH-1, at 37-38; NSTAR-Rebuttal-1, at 56-58). According to the Company, investors are aware of a company's decoupling mechanism and price a company's stock accordingly to account for the impact of decoupling (Company Brief at 170, citing Exh. NSTAR-RBH-1, at 36-39). For these reasons, the Company asserts that the Department should not adjust the ROE downward to account for the impact of these regulatory mechanisms (Company Brief at 149).

b. Analysis and Findings

In D.P.U. 07-50-A, the Department stated that, because decoupling is designed to ensure that distribution companies' revenues are not adversely affected by reductions in sales, by definition decoupling reduces earnings volatility. Such reduction in earnings volatility should reduce risks to shareholders and, therefore, should serve to reduce the required ROE. D.P.U. 07-50-A at 72; D.P.U. 07-50, at 1-2. The Department has stated that it will consider the impact of a decoupling mechanism on a distribution company, along with all other factors affecting that company's required ROE, in the context of a rate proceeding, where the evidence and arguments may be fully tested. D.P.U. 07-50-A at 74.

The same considerations apply to our assessment of the impact of a cost recovery mechanism on a company's risk. For a gas distribution company, a GSEP is designed to address the repair or replace aging or leaking natural gas infrastructure. G.L. c. 164, § 145; Bay State Gas Company, D.P.U. 14-134, at 2 (2015). Under a GSEP, a company may begin recovering estimated costs of eligible plant, including depreciation, property taxes, and return on investment associated with the plan. D.P.U. 14-134, at 4-5; G.L. c. 164, § 145(e). Such accelerated and, in many cases, pre-construction cost recovery should reduce risks to shareholders and, therefore, should serve to reduce the required ROE. Accordingly, based on the evidence and arguments presented in this case, the Department will consider the impact of the Company's revenue decoupling mechanism and the GSEP on its allowed ROE.

All companies in the Company’s proxy group have some form of decoupling or revenue stabilization mechanisms (Exhs. NSTAR-RBH-1, at 37; NSTAR-RBH-10). A review of the various mechanisms indicates that there is a wide range of approaches used for revenue stabilization from one regulatory jurisdiction to another, including full decoupling, weather normalization, straight fixed variable rate design and conservation incentive programs (Exhs. NSTAR-RBH-1, at 38-39; DPU-NSTAR-15-7, Att. (a); Tr. 8, at 685). Therefore, the fact that the comparison group of companies has revenue stabilization mechanisms does not mean that the comparison groups fully match the risk profile of the Company. Investors who consult 10-Q and 10-K filings are savvy enough to appreciate the distinction between a weather normalization adjustment and full decoupling. D.P.U. 13-75, at 326; D.P.U. 12-25, at 439. Accordingly, we do not accept NSTAR Gas’ argument that there is no need to consider the equity cost impact of decoupling because the proxy group uses some form of revenue stabilization mechanism. Likewise, we are not convinced that the Company’s proxy group fully captures the risk-reducing impact of the Company’s decoupling mechanism. The Department will, instead, examine the specific risk profile of the Company, and the specific features of the Company’s revenue decoupling mechanism, to arrive at the appropriate determination of the effect of risk on the Company’s required ROE.

Similarly, many of the companies in the Company’s proxy group have some form of infrastructure recovery mechanism for their operating affiliates in various jurisdictions (Exh. DPU-15-7, Att. (b) at 1-13). A review of the various mechanisms indicates that there are a wide range of approaches used in the various regulatory jurisdictions, including the range of eligible projects and the timing of cost recovery (Exh. DPU-15-7, Atts. (b) at 1-13, (c)).

Accordingly, the Department will examine the specific risk profile of the Company, and the specific features of the Company's GSEP, to arrive at the appropriate determination of the effect of risk on the Company's required ROE.

9. Conclusion

The standard for determining the allowed ROE is set forth in Bluefield at 692-693 and Hope at 603. The allowed ROE should preserve a company's financial integrity, allow it to attract capital on reasonable terms, and be comparable to returns on investments of similar risk. See Bluefield at 692-693; Hope at 603, 605. The allowed ROE should be determined "having regard to all relevant facts." Bluefield at 692.

The Company recommends that the Department approve an ROE of 10.25 percent (Exhs. NSTAR-RBH-1, at 3; NSTAR-RBH-Rebuttal-1, at 1). Alternately, the Attorney General recommends an ROE of 8.65 percent (Exh. AG-JRW-1, at 2, 50). The Department has found that both quantitative and qualitative factors must be taken into account in determining an allowed ROE. See, e.g., Boston Edison Company v. Department of Public Utilities, 375 Mass. 1, 11, cert. denied, 439 U.S. 921 (1978); Boston Gas Company v. Department of Public Utilities, 359 Mass. 292, 305-306 (1971); D.P.U. 11-01/D.P.U. 11-02, at 424; D.P.U. 08-27, at 134-138; D.T.E. 02-24/25, at 229-231; D.P.U. 92-78, at 115; D.P.U. 89-114/90-331/91-80 (Phase I) at 224-225. Thus, in determining an appropriate ROE for NSTAR Gas, the Department first evaluates the quantitative factors presented in this case.

In support of its recommended ROE, NSTAR Gas has presented quantitative analyses using the DCF model, the CAPM, and a bond yield plus risk premium approach, each incorporating the financial data of its gas proxy group. The Attorney General has presented her own analyses using the DCF model and the CAPM, incorporating the financial data of her gas proxy group. The use of empirical analyses in this context is not an exact science. A number of judgments are required in conducting a model-based rate of return analysis. Even in studies that purport to be mathematically sound and highly objective, crucial subjective judgments are made along the way and necessarily influence the end result. Western Massachusetts Electric Company, D.P.U 18731, at 59 (1977). Each level of judgment to be made in these models contains the possibility of inherent bias and other limitations. D.T.E. 01-56, at 117; D.P.U. 18731, at 59.

As discussed above, the evidence demonstrates that each equity cost model used by the Company and the Attorney General suffers from a number of simplifying and restrictive assumptions. Applying them to the financial data of a proxy group of companies could provide results that may not be reliable for the purpose of setting the Company's ROE. For example, we note the limitations of the DCF models used by both the Company and the Attorney General, including the simplifying assumptions that underlie the constant growth form of the model, its element of circularity, as well as the inherent limitations in comparing the Company to publicly traded companies. In particular, we find that the Company's DCF analysis overestimates the cost of equity by minimizing results of the low-outlier estimates. We also find that the Attorney General's DCF model retains some elements of circularity because investor expectations depend upon regulatory decisions.

The Department further finds that the CAPM analyses relied upon by the Company and the Attorney General are also flawed because of the simplifying assumptions underlying CAPM theory and the subjectivity inevitable in estimating market risk premiums. To the extent we rely on the CAPM estimates, we give more weight to the Attorney General's analysis because the magnitude of the deficiencies within the Company's proposed CAPM, including the estimate of a market risk premium, is greater. Finally, we find that the Company's bond yield plus risk premium approach suffers from a number of limitations and tends to overstate NSTAR Gas' required ROE.

The Department recognizes that the revenue decoupling mechanism approved for NSTAR Gas in this proceeding will reduce the variability of the Company's revenues and, accordingly, reduces its risks and its investors' return requirement. See D.P.U. 09-30, at 371-372; D.P.U. 07-50 A at 72-73. Although many companies in both proxy groups employ some form of revenue stabilization or decoupling mechanism, the Department finds that the degree of revenue stabilization varies among the companies and, on the whole, is not as comprehensive as the Company's decoupling mechanism (Exhs. DPU-NSTAR-15-7, Atts. (a), (b); AG-8-4, at 1187-1195).

The Department also recognizes that NSTAR Gas' GSEP, through accelerated and, in many cases, pre-construction cost recovery, serves to reduce the Company's risks and its investors' return requirement (Exhs. DPU-15-2; DPU-15-3; Tr. 11, at 936-937). Although many companies in both proxy groups employ some form of infrastructure recovery mechanism, these infrastructure recovery mechanisms vary among the companies, particularly insofar as the scope of eligible investments and the timing of cost recovery (Exh. DPU-15-7, Atts. (b); (c)). On the whole, the infrastructure recovery mechanisms for these companies are less comprehensive as the Company's GSEP (Exhs. DPU-15 7, Atts. (b), (c)).

Further, we note that a portion of the revenues of the companies in both proxy groups is derived from unregulated and competitive lines of business (Exhs. AG-8-3, Att. (b) at 91-97; JRW-10, AUS Utilities Reports, passim). All else equal, this mix of regulated and unregulated operations would tend to overstate the proxy groups' risk profiles relative to that of the Company. Therefore, in applying this comparability standard, we will consider such risk differentials when weighing the results of the models used to estimate the Company's allowed ROE.

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.[226] D.P.U. 08-35, at 219-220; D.P.U. 07-71, at 139; D.T.E. 01-56, at 118; D.P.U. 18731, at 59; see also 375 Mass. 1, 15. The Department must account for additional factors specific to a company that may not be reflected in the results of the models.

In determining the allowed ROE, the Department has also considered NSTAR Gas' use of reconciling mechanisms to recover certain costs, dollar-for-dollar, outside of base rates. The Company presently has in place fully reconciling mechanisms for a range of expenses, including

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226 As the Department stated in New England Telephone and Telegraph Company, D.P.U. 17441, at 9 (1973):

> Advances in data gathering and statistical theory have yet to achieve precise prediction of future events or elimination of the bias of the witnesses in their selection of data. Thus, there is no irrefutable testimony, no witness who has not made significant subjective judgments along the way to his conclusion, and no number that emerges from the welter of evidence as an indisputable "cost" of equity.

gas costs, energy efficiency costs, pension/PBOP expense, Attorney General consultant costs, supply-related bad debt and, as discussed above, the GSEP as a capital tracking mechanism to recover on a prospective basis investments in cast iron and unprotected steel infrastructure that will reduce regulatory lag in recovery. As a result of this Order, NSTAR Gas will retain these reconciling mechanisms, and implement a revenue decoupling mechanism. The use of these reconciling mechanisms covering a significant portion of the Company's expenses results in lower risk for NSTAR Gas than otherwise would be the case.

Finally, there are other qualitative factors that the Department will consider in determining a company's allowed ROE. It is both the Department's longstanding precedent[227] and accepted regulatory practice[228] to consider qualitative factors such as management

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[227] For example, the Department has set a utility's ROE at the low end of a range of reasonableness upon a showing that a utility's management performance was deficient. D.P.U. 12-86, at 257-258 (deficiencies regarding affiliate transactions and selection of rate case consultants warranted ROE at lower end of reasonable range); D.P.U. 11-43, at 218-222 (company's improper handling of a billing error, failure to provide acceptable unaccounted for water report, improper flushing practices, and insufficient communication with customers warranted ROE at lower end of reasonable range); D.P.U. 11-01/D.P.U. 11-02, at 424-426 (company shortcomings in storm response warranted ROE at lower end of reasonable range); D.P.U. 10-114, at 339-340 (company activities related to Department-ordered audit warranted ROE at lower end of reasonable range); D.P.U. 08-35, at 220 (customer service deficiencies warranted ROE at lower end of reasonable range); D.P.U. 08-27, at 136, 137 (failure to conduct competitive bidding for outside consultants and provide detailed rate case expense invoices warranted ROE at lower end of reasonable range); see also D.P.U. 85-266-A/271-A at 172 (failure to fulfill public service obligations warranted ROE at lower end of reasonable range).

[228] See, e.g., In re Citizens Utilities Company, 171 Vt. 447, 453 (2000) (general principle that rates may be adjusted depending on the adequacy of the utility's service and the efficiency of its management); US West Commc'ns, Inc. v. Washington Utils. and Transp. Comm'n, 134 Wash.2d 74, 121 (1998) (a utility commission may consider the quality of service and the inefficiency of management in setting a fair and reasonable rate of return); North Carolina ex rel. Utils. Comm'n v. Gen. Tel. Company of the Southeast, 285 N.C. 671, 681 (1974) (the quality of the service rendered is, necessarily, a factor to

performance and customer service in setting a fair and reasonable ROE. With respect to a company's performance, the Department has determined that where a company's actions have had the potential to affect ratepayers or have actually done so, the Department may take such actions into consideration in setting the ROE. D.P.U. 11-01/D.P.U. 11-02, at 424; D.T.E. 02-24/25, at 231; D.P.U. 85-266-A/271-A at 6-14. Thus, the Department may set ROEs that are at the higher or lower end of the reasonable range based on above average or subpar management performance and customer service. See, e.g., Milford Water Company, D.P.U. 12-86, at 257-258 (2013); D.P.U. 11-01/D.P.U. 11-02, at 424, 427.

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 ROE of 9.80 percent is within a reasonable range of rates that will preserve the Company's financial integrity, will allow it to attract capital on reasonable terms and for the proper discharge of its public duties, will be comparable to earnings of companies of similar risk and, therefore, is appropriate in this case. In making these findings, the Department has considered both qualitative and quantitative aspects of the parties' various methods for determining the Company's proposed ROE, as well as the arguments of and evidence presented by the parties in this proceeding.

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be considered in fixing the just and reasonable rate therefore); Gulf Power Company v. Wilson, 597 So.2d 270, 273 (1992) (regulator was authorized to adjust rate of return within reasonable range to adjust for mismanagement); Wisconsin Pub. Serv. Corp. v. Citizens' Util. Bd., Inc., 156 Wis.2d 611, 616 (1990) (prudence is a factor regulator considers in setting utility rates and can affect the allowed ROE).

XIII. RATE STRUCTURE

A. Rate Structure Goals

Rate structure is the level and pattern of prices charged to customers for their use of utility service. The rate structure for each rate class is a function of the cost of serving that rate class and how rates are designed to recover the cost to serve that rate class. The Department has determined that the goals of designing utility rate structures are to achieve efficiency and simplicity as well as to ensure continuity of rates, fairness between rate classes, and corporate earnings stability. D.P.U. 13-75, at 330; D.P.U. 12-25, at 444; D.P.U. 10-114, at 341; D.P.U. 09-39, at 401; D.T.E. 03-40, at 365; D.T.E. 02-24/25, at 252; D.T.E. 01-56, at 134; Blackstone Gas Company, D.T.E. 01-50, at 28 (2001).

Efficiency means that the rate structure is designed to allow a company to recover the cost of providing the service and to provide an accurate basis for consumers' decisions about how to best fulfill their needs. The lowest-cost method of fulfilling each consumer's needs should also be the lowest-cost method for society as a whole. Thus, efficiency in rate structure means setting cost-based rates that recover the cost to society of the consumption of resources used to produce the utility service. D.P.U. 13-75, at 330; D.P.U 12-25, at 445; D.P.U. 10-114, at 342; D.P.U. 09-39, at 401; D.T.E. 03-40, at 365-366; D.T.E. 02-24/25, at 252; D.T.E. 01-56, at 135. In practice, meeting the goal of efficiency should involve rate structures that provide strong signals to consumers to decrease energy consumption in consideration of price and non-price social, resource, and environmental factors.[229] D.P.U. 12-25, at 445.

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229 Effective use of energy resources means reducing the total amount of energy consumed without compromising service reliability through the use of more efficient technologies and practices, with clear and timely pricing information, as part of a sustainable energy

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 time 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.P.U. 13-75, at 331; D.P.U. 12-25, at 445; D.P.U. 10-114, at 342; D.P.U. 09-39, at 402; D.T.E. 03-40, at 366; D.T.E. 02-24/25, at 252-253; D.T.E. 01-56, at 135.

There are two steps in determining rate structure: cost allocation and rate design. The cost allocation step assigns for cost recovery purposes a portion of the company's total costs to each rate class through the use of an allocated cost of service study ("COSS"). The allocated cost of service represents the cost of serving each rate class at equalized rates of return given the company's level of total costs. D.P.U. 13-75, at 331; D.P.U. 12-25, at 446; D.P.U. 10-114, at 342; D.P.U. 09-39, at 402; D.T.E. 03-40, at 366; D.T.E. 02-24/25, at 253; D.T.E. 01-56, at 135; D.T.E. 01-50, at 29.

There are four steps in a COSS to develop an allocated cost of service. The first step is to 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 cost causation (i.e., demand, energy, or customer-related). The third step is to identify the most appropriate allocator to use to assign costs to each rate class for costs in each classification and within each function. The fourth step is to allocate all of a company's costs to each rate class based upon the cost groupings and

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policy. See An Act Relative to Green Communities, St. 2008, c. 169; An Act Establishing the Global Warming Solutions Act, St. 2008, c. 298.

allocators chosen, and then to sum for each rate class the costs allocated to it in order to determine the total costs of serving each rate class at equalized rates of return. D.P.U. 13-75, at 332; D.P.U. 12-25, at 446; D.P.U. 09-39, at 402-403; D.T.E. 03-40, at 366-367; D.T.E. 02-24/25, at 253; D.T.E. 01-56, at 136; D.T.E. 98-51, at 131-132; D.P.U. 96-50 (Phase I) at 133-134.

The results of the COSS are compared to the revenues collected in the test year for each rate class that have been weather normalized and adjusted for known and measurable changes. If the percentage difference in these amounts is close to the overall percentage increase granted, 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 percentage difference between the allocated cost and the test year revenue for a given rate class is significantly higher than the overall percentage increase granted, then, for reasons of continuity, the rate class revenue increase or decrease may be allocated so as to reduce the difference in rates of return among rate classes, but not to equalize them in a single step. D.P.U. 13-75, at 332; D.P.U. 12-25, at 446; D.P.U. 09-39, at 403; D.T.E. 02-24/25, at 253-254; D.T.E. 01-56, at 136; D.T.E. 01-50, at 29.

As the previous discussion indicates, the Department does not determine rates based solely on the results of a COSS, but also explicitly considers the effect of its rate structure decisions on the amount customers are billed. For instance, the pace at which fully cost-based rates are implemented depends in part on the effect of the changes on customers. In addition, considering the goals of efficiency and fairness, the Department has also ordered the establishment of special rate classes for certain low income customers and considers the effect of such rates and rate changes on low income customers. D.P.U. 13-75, at 332; D.P.U. 12-25, at 447; D.P.U. 09-39, at 403-404; D.T.E. 03-40, at 367; D.T.E. 02-24/25, at 254; D.T.E. 01-56, at 137; 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 class unless a clear record exists to support such subsidies – or unless such subsidies are required by statute, e.g., G.L. c. 164, § 1F(4)(I). 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.P.U. 13-75, at 333; D.P.U. 12-25, at 447; D.P.U. 09-39, at 404; D.T.E. 02-24/25, at 254; D.T.E. 01-56, at 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 each rate class in 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.P.U. 13-75, at 333; D.P.U. 12-25, at 447; D.P.U. 09-39, at 404; D.T.E. 03-40, at 368; D.T.E. 02-24/25, at 254-255; D.T.E. 01-56, at 136-137; D.T.E. 01-50, at 30.

B. COSS

1. Introduction

NSTAR Gas performed a COSS that assigns or apportions, based on cost-causation principles, the Company's total cost of service to each rate class[230] (Exhs. NSTAR-DAH-1, at 2-3; NSTAR-DAH-2, Schs. DAH-1 through DAH-6; DPU-2-2, Att. (a)). The identification of costs caused by each rate class is used to allocate the revenue requirement to rate classes and to design rates to recover the assigned revenue responsibility (Exh. NSTAR-DAH-1, at 3). The Company examined eight rate classes in its COSS: (1) R-1 (Residential Non-Heat); (2) R-3 (Residential Heating); (3) G-41 (Small Volume Low Load Factor Commercial and Industrial ("C&I")); (4) G-42 (Medium Volume Low Load Factor C&I); (5) G-43 (Large Volume Low Load Factor C&I); (6) G-51 (Small Volume High Load Factor C&I); (7) G-52 (Medium Volume High Load Factor C&I); and (8) G-53 (Large Volume High Load Factor C&I) [231] (Exh. NSTAR-DAH-1, at 7).

The Company's cost allocation procedure involved several steps. First, the Company separated plant investment costs and operating expenses into the operational functions to which they are associated (e.g., storage, transmission, distribution, and customer service) (Exh. NSTAR-DAH-1, at 4). Second, the Company classified costs as related to demand,

[230] The Company updated the inputs in its COSS revenue requirement model throughout the course of the proceeding. In particular, the Company updated its COSS to include its updated revenue requirement (as of June 15, 2015) and the use of 2014 billing determinants (RR-AG-16, Att.). The Company also provided this same information updated to include weather-normalized high load factor rate classes (RR-AG-15, Att.).

[231] For the purposes of the COSS and rate design, rate classes R-1 (Residential Non-Heat) and R-2 (Low Income Non-Heat) are grouped together, and rate classes R-3 (Residential Heating) and R-4 (Low Income Heating) are grouped together.

customer, or commodity service[232] (Exhs. NSTAR-DAH-1, at 7; NSTAR-DAH-2, Sch. DAH-3). Third, the Company allocated or assigned the functionalized and classified costs to the various customer rate classes through either external or internal allocation factors (Exhs. NSTAR-DAH-1, at 5; NSTAR-DAH-2, Sch. DAH-4, at 1-6; DPU-2-2, Att. (a)). In this regard, external allocation factors (such as volumes, number of customers, peak usage, normalized throughput by class, and revenues by class) were developed by the Company from its customer information records (Exhs. NSTAR-DAH-1, at 5; DPU-4-2). Internal allocation factors were developed by the Company within the COSS and based on prior calculations and allocations from allocated plant investment or functional O&M costs (Exhs. NSTAR-DAH-1, at 5; NSTAR-DAH-2, Sch. DAH-4; DPU-2-2, Atts. (b) through (g); DPU-4-2).

The Company contends that its COSS properly allocates its embedded costs and, therefore, should be adopted for purposes of developing its proposed rate design (Company Brief, at 182). No other party commented on the Company's COSS.

2. Analysis and Findings

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. A company's compliance with this policy satisfies the Department's goal of ensuring that rates are fair. D.P.U. 92-210, at 214; D.P.U. 92-250, at 194; Western Massachusetts Electric Company, D.P.U. 89-255, at 103 (1990). The Department has

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232 Customer costs are a function of the number of customers served and may include capital costs associated with distribution mains, services, meters, regulators, and accounting expenses (Exh. NSTAR-DAH-1, at 4). Demand costs are fixed in nature and are incurred to meet the customer's peak load requirements (Exh. NSTAR-DAH-1, at 4). Commodity costs vary in relation to the volume of gas consumed by the customer (Exh. NSTAR-DAH-1, at 5).

evaluated NSTAR Gas' proposed COSS, as described above, and finds that it has assigned or allocated the Company's total distribution costs to each rate class consistent with Department precedent for cost allocation. D.P.U. 13-75, at 334; D.T.E. 03-40, at 369; D.T.E. 01-56, at 138; D.P.U 96-50 (Phase I) at 136. The Department therefore approves NSTAR Gas' proposed COSS model. In the compliance filing to this proceeding, the Company shall rerun its COSS model using the costs and expenses approved in this Order.

C. Marginal Cost Study

1. Introduction

The use of a marginal cost study facilitates the development of rates that provide consumers with price signals that accurately represent the costs associated with consumption decisions. D.P.U. 11-01/D.P.U. 11-02, at 438; D.P.U. 10-55, at 524. Rates based on a marginal cost study allow consumers to make informed decisions regarding their use of utility services, promoting efficient allocation of societal resources. D.P.U. 11-10/D.P.U. 11-02, at 438; D.P.U. 10-55, at 524; D.T.E. 03-40, at 372.

In support of its rate case filing, NSTAR Gas prepared a marginal cost study for its gas operations (Exhs. NSTAR-JDS-1, at 2-16; NSTAR-JDS-2; NSTAR-JDS-3). The Company excluded from the study all production, transmission and customer costs (Exh. NSTAR-JDS-1, at 3). NSTAR Gas limited the marginal cost study to an estimation of marginal capacity-related distribution costs (Exh. NSTAR-JDS-1, at 4). In this regard, the Company estimated the marginal capacity-related distribution plant, marginal capacity-related operations expenses, marginal capacity-related maintenance expense, and three ancillary components: marginal general plant, marginal administrative and general expense, and marginal materials and supplies expense (Exh. NSTAR-JDS-1, at 4-5). As for the data used in the marginal cost study, NSTAR Gas relied upon historical degree-day data, as well as plant, expense, peak demand, and customer data from the Company's Annual Reports submitted to the Department for 1984 to 2013 (Exh. NSTAR-JDS-1, at 5). The Company used this information to create various data series for use in the marginal cost study (Exh. NSTAR-JDS-1, at 5-7).

To develop the marginal cost study, the Company performed multi-variate regression analyses that used the 29 years of historical data to test for the sets of explanatory variables that best explained statistical variations in the dependent variable being estimated (Exhs. NSTAR-JDS-1, at 4, 8-14; NSTAR-JDS-2; Tr. 4, at 325). First, the Company estimated the capacity-related distribution plan investment, excluding customer-related investments to serve growth (Exhs. NSTAR-JDS-1, at 10-11; NSTAR-JDS-2, Sch. JDS-1). The Company then estimated the marginal cost of capacity-related distribution O&M expenses (Exhs. NSTAR-JDS-1, at 11; NSTAR-JDS-2, Sch. JDS-2). Next, NSTAR Gas estimated marginal loading factors for administrative and general expenses, materials and supplies expenses, and general plant (Exhs. NSTAR-JDS-1, at 11-13; NSTAR-JDS-2, Sch. JDS-3). The Company then calculated a fixed carrying charge rate that was used to convert the marginal cost of plant additions from a cost that represents the estimated marginal investment into the levelized annual cost of that investment (Exhs. NSTAR-JDS-1, at 13; NSTAR-JDS-2, Sch. JDS-4). Finally, NSTAR Gas calculated the total loss-adjusted marginal cost to provide distribution service to each of the Company's rate classes (Exhs. NSTAR-JDS-1, at 14; NSTAR-JDS-2, Sch. JDS-5, at 2-3; Tr. 4, at 319-321).

In addition to the regression analyses described above, the Company developed additional analyses to separate the total marginal costs into three categories: (1) system expansion, (2) reinforcement of the core system, and (3) replacement of the core system (Exhs. NSTAR-JDS-1, at 14-15; NSTAR-JDS-2, Sch. JDS-5, at 4-5). NSTAR Gas assigned marginal plant-related costs (distribution and general plant) to the growth-related categories of system expansion and reinforcement[233] based on the relative shares of the Company's 2004 to 2013 plant additions for these two categories (Exhs. NSTAR-JDS-1, at 15; NSTAR-JDS-2, Sch. JDS-5, at 4-5). NSTAR Gas assigned marginal expense-related costs (distribution, administrative and general, and working cash revenue requirement) to system expansion, reinforcement and replacement[234] based on the relative shares of the Company's NSTAR 2004 to 2013 plant additions for all three of these categories (Exhs. NSTAR-JDS-1, at 15 & n.4; NSTAR-JDS-2, Sch. JDS-5, at 4-5). The Company states that this additional analysis provides marginal cost detail that can be used in setting a floor price for interruptible transportation and special contract customers and to determine annual revenue guarantees for dual fuel contracts (Exhs. NSTAR-JDS-1, at 15-16; NSTAR-JDS-2, Sch. JDS-5, at 4-5; Tr. 4, at 313-315).

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233 The Company states that marginal plant-related costs measure the incremental costs that result from an increment in demand (Exh. NSTAR-JDS-1, at 15 n.3). According to the Company, replacement costs are not caused by incremental demand and, therefore, they are not a marginal cost (Exh. NSTAR-JDS-1, at 15 n.3).

234 The Company states that marginal expense-related costs are incurred to perform O&M activities on all categories of the distribution system and, therefore, these costs are assigned to the system expansion, reinforcement and replacement categories (Exh. NSTAR-JDS-1, at 15 n.4).

2. Positions of the Parties

The Company argues that its marginal cost study was conducted properly and is fully consistent with Department precedent (Company Brief at 182-183, citing D.P.U. 13-75, at 336-337). In particular, the Company notes that the marginal cost study was limited to the estimation of marginal capacity-related distribution costs rather than marginal customer-related distribution costs (Company Brief at 183, citing Exh. NSTAR-JDS-1, at 4-5). Further, the Company contends that (1) the historical data it used was reviewed for accuracy and reliability, and to identify unusual patterns and discontinuities in the data series, while (2) regression analyses were used to test variables that best explained the statistical variations (Company Brief at 183, citing Exh. NSTAR-JDS-1, at 4-5). Finally, the Company asserts that its marginal cost study establishes accurate floor prices for interruptible contracts and special contracts, and annual revenue guarantees for dual fuel contracts (Company Brief at 183, citing Exhs. NSTAR-JDS-1, at 15; NSTAR-JDS-2, Sch. 5, at 5; Tr. 4, at 313). No other party commented on the Company's marginal cost study.

3. Analysis and Findings

The Department finds that the marginal cost study developed by NSTAR Gas incorporates sufficient detail to allow a full understanding of the methods used to determine the marginal cost estimates. Consistent with the directives in D.T.E. 05-27, at 322 & n.170, the Company has excluded from its marginal cost study all production, transmission and customer costs as they are not relevant to the design of distribution rates under the Department's current ratemaking policies (Exh. NSTAR-JDS-1, at 3). We find that the Company used reliable data to develop the marginal cost study (Exh. NSTAR-JDS-1, at 5; D.T.E. 03-40, at 376-377). In addition, we find that the Company used proper econometric techniques to provide a statistically reliable estimate of the marginal plant-related costs, O&M expenses, and the marginal loading factors (Exhs. NSTAR-JDS-1, at 10-13; NSTAR-JDS-2, Schs. JDS-1, JDS-2, JDS-3). NSTAR Gas used appropriate historical data in its regression analyses, encompassing a 29-year period from 1984 to 2013 (Exh. NSTAR-JDS-1, at 5; Tr. 4, at 325). Further, the Company used multi-variate regression techniques and performed appropriate diagnostic tests to ensure the appropriateness of the regressions in its marginal cost study (Exhs. NSTAR-JDS-1, at 4, 8-14; NSTAR-JDS-2).

Based on the foregoing, the Department concludes that NSTAR Gas used the most robust marginal cost model available. Accordingly, we accept the Company's proposed marginal costs.

D. Residential Assistance Adjustment Clause

1. Introduction

In August 2003, the Department established an automatic enrollment program for the purpose of increasing participation in the low-income discount rate. Low-Income Discount Rate Participation Rate, D.T.E. 01-106-A (2003). The Department directed electric and gas companies to exchange information with the Executive Office of Health and Human Services on a quarterly basis so that every recipient of a means-tested public benefit who is also the electric and/or gas customer of record would be automatically enrolled in the discount rate without the usual paper application. D.T.E. 01-106-A at 10, 13. In 2006, the Department established standards for electric and gas arrearage management programs to help eligible customers pay overdue utility bills with payment programs, debt forgiveness, or a combination of the two. Order Establishing Standards for Arrearage Programs for Low-Income Customers, D.T.E. 05-86, at 10, 14-15 (2006). The Department determined that the appropriate cost recovery mechanism for both the revenue shortfall caused by the discount rate and incremental AMP expenses was the Residential Assistance Adjustment Factor ("RAAF"). D.T.E. 01-106-C/05-55/05-56, at 11, 14; D.T.E. 05-86, at 12-13.[235]

NSTAR Gas' recovery of the revenue shortfall caused by the discount rate and incremental AMP expenses is governed by provisions set forth in its Residential Assistance Adjustment Clause ("RAAC") tariff, M.D.P.U. No. 407C. The RAAC tariff contains a net cost/benefit formula which was approved by the Department as part of a settlement agreement in D.T.E. 05-85 (Exh. NSTAR-RDC-4, at 137-138 (M.D.P.U. No. 407C § 1.05)). See D.T.E. 05-85, at 9-10, 33. The formula sets forth the method by which the Company recovers AMP-related costs. Specifically, pursuant to the formula, reasonable costs associated with the AMP in excess of the benefits are reconciled annually through the RAAF. D.T.E. 05-85, at 10.

2. Company Proposal

NSTAR Gas proposes to close its RAAC tariff and incorporate the provisions of the RAAC, with several modifications, into a revised LDAC tariff (Exhs. NSTAR-RDC-4, at 37-38; NSTAR-RDC-6, at 106-109 (proposed M.D.P.U. No. 402G § 7.0)). First, the Company proposes to eliminate the net cost/benefit formula applicable to the Company's AMP costs (Exhs. NSTAR-RDC-4, at 39). The Company proposes, instead, to recover each year through the RAAF, all AMP costs, whether or not the costs exceed the benefits (Exh. NSTAR-RDC-4,

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235 Prior to the establishment of the RAAF, the revenue shortfall from the low-income discount was recovered in base rates. See, e.g., D.T.E. 03-40, at 385; D.T.E. 01-106-C/05-55/05-56, at 7.

at 39-40). During the test year, the Company sought recovery of $627,574 in AMP costs using the net cost/benefit formula (Exhs. NSTAR-RDC-4, at 40-41; NSTAR-MFF-4, Sch. MFF-2). The Company states that, without the formula, it would have been eligible to collect an additional $60,947 in AMP costs in 2014. Therefore, the Company proposes to add $60,947 to its test year revenue requirement (Exhs. NSTAR-RDC-4, at 41; NSTAR-MFF-4, Sch. MFF-2 (August 21, 2015)).

Second, the Company proposes to modify the RAAF formula to make the language consistent with language found the Company's residential low income tariffs (Exhs. NSTAR-RDC-4, at 39; NSTAR-RDC-6, at 108 (proposed M.D.P.U. No. 402G § 7.4), 136 (M.D.P.U. No. 407C § 1.05)). Third, the Company proposes to update the language of the tariff describing the purpose of the RAAC and to remove references to items it describes as no longer relevant (Exhs. NSTAR-RDC-4, at 39; NSTAR-RDC-6, at 107 (proposed M.D.P.U. No. 402G § 7.1)).

3. Positions of the Parties

a. LEAN

LEAN argues that the AMP is a legislatively mandated program and that the reconciliation of costs associated with the AMP is important to maintain flexibility of program design (LEAN Brief at 7). LEAN notes that Department previously determined that a reconciling factor was appropriate for AMP costs and that circumstances have not changed such that a departure from this policy is warranted (LEAN Brief at 4-6, citing Expanding Low-Income Consumer Protections and Assistance, D.P.U. 08-4, at 1-2 (2008); Tr. 14, at 1168-1171).

Accordingly, LEAN asserts that the costs of the Company's AMP should continue to be fully reconciled through the RAAF (LEAN Brief at 5, 7).

b. Company

The Company argues that the elimination of the net cost/benefit formula is reasonable because it has proven to be an inappropriate means of evaluating the cost-effectiveness of the AMP (Company Brief at 28). In addition, NSTAR Gas contends that the formula is no longer needed because the Department has stated that AMPs are legislatively mandated and, therefore, need not be cost effective (Company Brief at 28, citing Exh. NSTAR-RDC-4, at 40). In this regard, the Company asserts that it implemented significant expansions to its AMP in 2014 and that the formula does not produce an accurate representation of the costs of expanding its AMP (Company Brief at 28-29).

NSTAR Gas urges the Department to continue operation of the RAAF (Company Brief at 29). The Company asserts that its AMP costs have fluctuated considerably in recent years and, therefore, it would be difficult to establish a representative level of AMP costs to include in base rates (Company Brief at 29, citing Exh. LEAN-1-3, Att.; Tr. 14, at 1163-1164). In addition, the Company argues that a move to base rate treatment of AMP costs would hinder the Company's flexibility to modify its AMP between rate cases (Company Brief at 29). Specifically, NSTAR Gas argues that establishing a representative level of AMP costs in base rates would: (1) inhibit the Company from making enhancements to its AMP, if those enhancements result in increased costs; (2) cause it to reevaluate the size and scope of its AMP, if the representative level in base rates is set too low; and (3) make it difficult for gas distribution companies to adjust AMPs in order to ensure that the programs are comparable (Company Brief at 29).

4. <u>Analysis and Findings</u>

As described above, NSTAR Gas proposes to close its RAAC tariff and incorporate the RAAC provisions, with several modifications, into a revised LDAC tariff (Exhs. NSTAR RDC-4, at 37-38; NSTAR-RDC-6, at 106-109 (proposed M.D.P.U. No. 402G § 7.0)) Incorporating the RAAC provisions into the LDAC tariff is consistent with other gas LDCs whose LDAC tariffs govern low income cost recovery (<u>i.e.</u>, the revenue shortfall caused by the low income discount rate and incremental AMP costs) (Exh. NSTAR-RDC-4, at 38). <u>See</u> Boston Gas Company, M.D.P.U. No. 3.5, §§ 6.08 and 6.13; Colonial Gas Company, M.D.P.U. No. 3.5, §§ 6.08 and 6.13. The Department finds that it is more efficient to address all low income cost recovery issues through one umbrella tariff (<u>i.e.</u>, the LDAC tariff), rather than in separate LDAC and RAAC tariffs. Accordingly, the Department approves the Company's proposal to close its RAAC tariff and, instead, incorporate the provisions of the RAAC in its revised LDAC tariff.

The Company proposes several modifications to the RAAC provisions. The first concerns the elimination of the AMP net cost/benefit formula. The net cost/benefit formula was established as part of a settlement approved by the Department in D.T.E. 05-85. <u>See</u> D.T.E. 05-85, at 9-10, 33. Pursuant to the formula, reasonable costs associated with the AMP in excess of the benefits are reconciled and recovered annually through the RAAF. D.T.E. 05-85, at 10.

AMPs are legislatively mandated by St. 2005, c. 140, § 17 and there is no statutory requirement that they be cost effective. 2013 Arrearage Management Programs, D.P.U. 13-AMP-01 through D.P.U. 13-AMP-08, at 9 (July 17, 2014). No other gas or electric distribution company currently uses a net cost/benefit formula as part of its recovery of AMP costs. See e.g., Boston Gas Company, M.D.P.U. No. 3.5, § 6.13; Colonial Gas Company, M.D.P.U. No. 3.5, § 6.13. Because the settlement in D.T.E. 05-85 that established the net cost/benefit formula is no longer in effect, there is currently no basis to require that the Company maintain the net cost/benefit formula. Accordingly, the Department allows the Company's proposal to eliminate the net cost/benefit formula from the revised RAAC.

As a result of the elimination of the net cost/benefit formula, the Company proposes to add $60,947 to its test year revenue requirement to account for AMP costs it contends it should now be able to recover (Exhs. NSTAR-RDC-4, at 41; NSTAR-MFF-4, Sch. MFF-2 (August 21, 2015)). Elimination of the net cost/benefit formula only applies to AMP costs incurred after the effective date of the rates approved in this Order. There is no basis to allow any adjustment to test year AMP costs as a result of the elimination of the net cost/benefits formula. Accordingly, the Department rejects the Company's proposed adjustment, and we will reduce the amount proposed to be recovered through the LDAC by $60,947.

The Company proposes two other modifications to the RAAC provisions, as described above. The Department finds that these proposed revisions are intended either to make the RAAC language consistent with language in the Company's residential low income tariffs or to eliminate references in the RAAC that are no longer relevant. After review, the Department finds that such revisions are appropriate. Accordingly, we allow the proposed revisions.

Based on the above considerations, the Company is directed to close its RAAC tariff, M.D.P.U. No. 407C, as of December 31, 2015. As part of the compliance filing to this Order, the Company shall incorporate the RAAC provisions, with the modifications approved herein, into a revised LDAC tariff for effect January 1, 2016.

E. Rate Design

1. Company Proposal

The Company determined class revenue requirements using the results of its COSS (Exh. NSTAR-RDC-4, at 6). Pursuant to General Laws c. 164, § 94I ("Section 94I"), the Company evaluated these base revenue targets to determine if they would cause any customer class to receive a rate increase greater than ten percent of total adjusted test year revenues (Exh. NSTAR-RDC-4, at 7).

To the extent that any customer class base rate increase was over ten percent of the class' total adjusted test year revenues, the Company allocated the excess amount to the other rate classes that were not over the cap, thereby capping each class' base revenue increase at ten percent (Exhs. NSTAR-RDC-4, at 9; NSTAR-RDC-5, Sch. RDC-1). The Company proposes to allocate the revenues in excess of the ten percent cap, by rate class, to the remaining rate classes based on the ratio of each remaining class' test year base revenue target to the group's total test year base revenue target (Exhs. NSTAR-RDC-4, at 9; NSTAR-RDC-5, Sch. RDC-1).

Using this method, the Company determined that the R-1 and R-2 rate classes exceeded the ten percent cap. Accordingly, the Company proposes to cap the base revenue increase for the R-1 and R-2 rate classes at ten percent of their proposed adjusted test year revenues (Exhs. NSTAR-RDC-4, at 9; NSTAR-RDC-5, Sch. RDC-1).

The Company also proposes to cap the base distribution rate increase to each rate class at no more than 126 percent of the base distribution rate increase (Exhs. NSTAR-RDC-4, at 9; NSTAR-RDC-5, Sch. RDC-1). The Company proposes to allocate revenues in excess of the 126 percent cap to any rate classes that did not exceed the ten percent cap described above (Exh. NSTAR-RDC-4, at 10). The Company states that the 126 percent cap is designed to limit the difference in base distribution rate increases for one rate class relative to other rate classes, while minimizing cross-subsidization (Exh. NSTAR-RDC-4, at 10). The Company states that the beneficiary of this cap is the G-53 rate class[236] (Exh. NSTAR-RDC-4, at 9).

The Company proposes to increase the current discount for the low income R-2 and R-4 rate classes to 25 percent.[237] At current rates, the Company states that the total test year low income discount was $5,142,753 (RR-DPU-18, Att. (a) at 10). At 25 percent, the Company states that the total test year low income discount would be $7,531,755 (RR-DPU-18, Att. (a) at 11). Accordingly, the Company states that its proposed 25 percent low income discount would result in an incremental cross-subsidy of $2,389,002 ($7,531,755 minus $5,142,753) to be applied across all rate classes (see RR-DPU-18, Att. (a) at 10-11).

To design rates for each rate class, the Company states that it first chose a customer charge based on a goal to move towards the cost to serve that class, with consideration of any ensuing intra-class bill impacts (Exh. NSTAR-RDC-4, at 13). The Company states that its current customer charges are, on average, 27 percent of the full cost of service. Under its rate

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236 The Company maintains that, absent the 126 percent cap, the G-53 rate class would experience a 53.4 percent increase in base distribution rates; however, it would experience only a 6.2 percent bill impact (Exh. NSTAR-RDC-4, at 9).

237 Currently, the R-2, and R-4 rate classes receive an 18.8 percent and 18.4 percent discount on the total bill, respectively (Exh. NSTAR-RDC-4, at 12).

design proposal, the Company states that customer charges would move, on average, to 58 percent of the full cost of service (Exh. NSTAR-RDC-4, at 13).

Next, the Company calculated customer revenues by multiplying the proposed customer charges by the test year number of bills (Exh. NSTAR-RDC-4, at 14). Finally, the Company divided the remaining revenue requirement by the adjusted test year sales to derive the volumetric rate (Exh. NSTAR-RDC-4, at 14).

The Company proposes to eliminate both block rates and seasonal rate differentials for all residential customer classes (see Exh. NSTAR-RDC-4, at 16, 17). The C&I rate classes currently do not use block rates. The Company proposes to continue a flat volumetric rate for all C&I rate classes (see Exh. NSTAR-RDC-4, at 17). The Company proposes to continue the seasonal rate differential for the high- and medium-use C&I rate classes but eliminate it for the low-use C&I rate classes (see Exh. NSTAR-RDC-4, at 16).

The Company reviewed the results of the COSS to inform its seasonal rate design proposal (Exh. NSTAR-RDC-4, at 16). The results of the COSS produce higher off-peak volumetric rates for the residential and the G-41 rate classes because of a large difference in gas use in the off-peak period compared to the peak period (Exh. NSTAR-RDC-4, at 16). To address this issue, the Company proposes to annualize the rates for the residential and G-41 rate classes (Exh. NSTAR-RDC-4, at 16). NSTAR Gas proposes to maintain the existing seasonal revenue allocation for the remaining C&I rate classes, using the seasonal allocations from its COSS adjusted to account for the resulting bill impacts (Exh. NSTAR-RDC-4, at 16).

The Company proposes to consolidate the T-1 and G-53 rate classes (Exhs. NSTAR-RDC-4, at 17-18; DPU-4-9). The Company states that the rate T-1 is a closed firm transportation rate (Exh. NSTAR-RDC-4, at 18). The Company states that in the test year, there were ten customers taking service under this rate, three of which have since migrated to another rate class (Exh. NSTAR-RDC-4, at 18). The Company proposes to transfer six of the remaining customers to rate G-53 and one customer to rate G-43 (Exhs. NSTAR-RDC-4, at 18; DPU-4-8). The Company also proposes to terminate its outdoor lighting rate class, rate S-1 (Exh. NSTAR-RDC-4, at 19). The Company states that there are no longer any customers taking service under this rate (Exh. NSTAR-RDC-4, at 19).

Finally, the Company proposes to eliminate the default service demand charge adjustment and the default service energy credit adjustment for its rate G-53 customers (Exh. NSTAR-RDC-4, at 25). NSTAR Gas states that these adjustments were introduced in 1998 in order to ensure that customers would not be harmed on the basis of load factor as they transitioned to unbundled rates (Exh. NSTAR-RDC-4, at 25). NSTAR Gas states that nine customers remain in this rate class as of October 2014 (Exh. NSTAR-RDC-4, at 25).

2. Positions of the Parties

a. Attorney General

In response to issues she identified in the instant COSS, the Attorney General asserts that the Company should review its property records in preparation for any future base rate proceeding to more accurately allocate services costs (Attorney General Brief at 71; Attorney General Reply Brief at 37). The Attorney General argues that, because services costs are the primary customer-related costs making up the customer charge, services costs should be allocated as accurately as possible (Attorney General Brief at 71).

In particular, the Attorney General argues that in any future COSS, the Company must ensure that residential and small C&I customers are properly allocated the correctly sized services (Attorney General Brief at 70; Attorney General Reply Brief at 37). In this regard, the Attorney General contends that the Company, as a result of miscoding in its property records, initially allocated to residential rate classes over 9,000 services that were in excess of two inches in size[238] (Attorney General Brief at 70, citing Exh. DPU-2-2; Attorney General Reply Brief at 37, citing RR-AG-17). Moreover, the Attorney General contends that the Company incorrectly allocated to small C&I rate classes, services that were in excess of two inches (Attorney General Reply Brief at 37, citing RR-AG-17). Finally, the Attorney General argues that there were a large number of services in the property records of undetermined material type that should be better identified by the Company (Attorney General Reply Brief at 37, citing RR-AG-17).

In addition, the Attorney General argues that the Company incorrectly interprets Section 94I to restrict its application of the ten percent cap to increases in base distribution rates and not to reconciling mechanisms (Attorney General Brief at 71, citing Exh. NSTAR-RDC-5, Schs. 1, 5). According to the Attorney General, Section 94I does not explicitly limit the ten percent cap to base distribution rates (Attorney General Brief at 71). Therefore, the Attorney General maintains that the Department can and should exercise its ratemaking authority and apply the cap to all rate increases, including the Company's proposed $12.0 million increase in

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238 The Attorney General asserts that it is unusual for residential customers (particularly residential non-heating customers) to have services in excess of two inches (Attorney General Brief at 70, citing Tr. 9 at 814). The Attorney General maintains that the Company subsequently revised its service allocator to exclude services in excess of two inches (Attorney General Brief at 71, citing RR-AG-15; RR-AG-16).

costs recovered through reconciling mechanisms (Attorney General Brief at 72-75, citing Exh. NSTAR-MFF-4, Sch. 1; Tr. 9, at 819; RR-DPU-18, Att. (a) at 5; Attorney General Reply Brief at 38).

The Attorney General contends that applying the cap to all rate increases is appropriate because through the instant rate proposal, as well as through the implementation of new cost recovery mechanisms such as the GSEP, the Company will significantly increase the percentage of costs to be collected through reconciling mechanisms that are now collected in base distribution rates.[239] The Attorney General argues that, in order to ensure fairness and rate continuity, the Department must include reconciling mechanism increases when it considers the rate impacts to customer classes and increases to customers within those classes (Attorney General Brief at 74).

Further, the Attorney General argues that in D.P.U. 13-75, the Department established guidelines regarding the appropriate cap on base distribution rate increases to individual rate classes and that such guidelines should be applied in this case (Attorney General Brief at 75-76 citing D.P.U. 13-75, at 362, 422). Specifically, the Attorney General argues that the Department found it was appropriate to limit the increase to any rate class to no more than 200 percent of the overall base distribution rate increase[240] (Attorney General Brief at 75 citing D.P.U. 13-75, at 362, 422). The Attorney General maintains that the Department found that a cap of

239 The Attorney General notes that the Company currently collects 75 percent of its revenues (or $150 million) through its base distribution rates and 25 percent of its revenues (or $51 million) through reconciling mechanisms (Attorney General Brief at 72, citing Tr. 13, at 1087).

240 According to the Attorney General, the 200 percent cap on distribution rate increases should be applied after the ten percent cap on the overall class revenue increase (Attorney General Brief at 75; Attorney General Reply Brief at 39, citing D.P.U. 13-75, at 362).

200 percent meets the rate structure goals of fairness and continuity (Attorney General Brief at 75, citing D.P.U. 13-75, at 362; Attorney General Reply Brief at 39).

The Attorney General argues that, in light of the Department's findings in D.P.U. 13-75, the Company's proposal to establish a rate class cap of 126 percent of the total distribution rate increase is not appropriate (Attorney General Brief at 76, citing Exh. AG-RSB-1, at 8; Attorney General Reply Brief at 39). In the instant case, the Attorney General contends that the Company's G-53 rate class is under recovering its costs and, therefore, will benefit from the application of a rate class cap (Attorney General Brief at 76). The Attorney General contends that applying a 200 percent cap to the G-53 rate increase results in a class distribution rate increase of 26.8 percent and a total bill increase of 5.8 percent (which is less than the overall average increase of 6.8 percent) (Attorney General Brief at 76, citing RR-DPU-24, Att. 1). The Attorney General asserts that the 200 percent increase, as opposed to the 126 percent increase proposed by the Company, moves the G-53 rate class closer to equalized rates of return, tempers intra-class subsidies, and will not result in undue hardship to this class of customers as the increase is less than the overall average increase (Attorney General Brief at 76; Attorney General Reply Brief at 39). Based on the above, the Attorney General argues that the Department should find that a 200 percent rate cap is applicable in this case, as well as for other distribution company rate class increases in future rate cases (Attorney General Reply Brief at 39).

Finally, the Attorney General opposes the Company's proposal to increase current residential customer charges by nearly 50 percent and current C&I customer charges by as much as 250 percent (Attorney General Brief at 76, citing Exh. AG-RSB-6, at 11, Table 8). The Attorney General contends that the Company's proposed customer charge increases are excessive and will result in adverse bill impacts for low-use customers within each rate class (Attorney General Brief at 77). In response to the Company's argument that higher customer charges will improve efficiency by recovering a higher percentage of customer-related costs through the customer charge, the Attorney General submits that such goals cannot be furthered without also considering rate continuity and bill impacts to lower-use customers within each rate class (Attorney General Brief at 77). Balancing these goals, the Attorney General recommends that the Department limit the customer charge increases to 15 percent for all but the largest C&I rate classes (Attorney General Brief at 77-78, citing Exh. AG-RSB-6, at 11, Table 8). For the largest C&I rate classes (i.e., rates G-43 and G-53), the Attorney General recommends that the Department limit the customer charge increases to 25 percent[241] (Attorney General Brief at 77-78, citing Exh. AG-RSB-6, at 11, Table 8).

The Attorney General submits that her recommended customer charges are more reasonable than those proposed by the Company and are more consistent with the customer charges approved by the Department in D.P.U. 13-75 (Attorney General Brief at 77, citing Exh. AG-RSB-1, at 10-11). Further, the Attorney General asserts that her recommended customer charges will: (1) achieve moderated and balanced increases to each rate class' customer charge; (2) reduce the rate increase percentages for low use customers within each rate class; and (3) yield small incremental increases to higher-use customers in each class (Attorney General Brief at 76-78; Attorney General Reply Brief at 40).

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241 The Attorney General argues that the customer charge is a small percentage of the bill for the largest C&I rate classes and, therefore, a higher limit is appropriate (Attorney General Brief at 77).

b. DOER

DOER supports the Attorney General's recommended increases to the customer charges (DOER Brief at 8). DOER argues that the Attorney General's recommended customer charges better effectuate rate continuity and mitigate bill impacts associated with NSTAR Gas' proposed rate increase (DOER Brief at 8, citing Exh. AG-RSB-6, at 10-11, Table 8). Finally DOER argues that with the decoupling mechanism, NSTAR Gas is assured of recovering its costs whether they are included in the fixed or the variable components of the Company's rate (DOER Brief at 8).

c. TEC

TEC agrees with the Attorney General's recommendation that the Department consider the Company's other rate mechanisms when examining the impact of the propose rate increases on customers (TEC Reply Brief at 4, citing Attorney General Brief at 73). In addition, TEC agrees with the Attorney General and DOER that the Company should be required to adopt more moderate increases in customer charges in order to better ensure rate continuity (TEC Reply Brief at 6). TEC asserts that the Company's proposed customer charges were chosen with no consideration of rate continuity and that the Company's revenue decoupling proposal ensures cost recovery regardless of whether the distribution revenue requirement is recovered in the fixed or variable portion of the rate (TEC Reply Brief at 6).

d. Company

NSTAR Gas disagrees with the Attorney General's recommendation that it be required to review its property records before any future base rate proceeding (Company Brief at 194, citing Attorney General Brief at 71). The Company argues that such a requirement would be unduly burdensome and is unjustified (Company Reply Brief at 58). In particular, the Company contends that, while it may have miscoded some services to residential rate classes, such miscoding pertained to a small amount of the Company's assets and did not have any material impact on the Company's cost allocation analysis[242] (Company Brief at 194; Company Reply Brief at 58).

Further, NSTAR Gas disputes the Attorney General's claim that the overall ten percent cap on rate increases mandated by Section 94I should take into account reconciling mechanisms and not just base distribution rates (Company Brief at 194-195). The Company asserts that the Department has previously accepted that the ten percent cap is applicable only to base distribution rates (Company Brief at 195, citing D.P.U. 13-90, at 276; D.P.U. 13-75, at 393).

The Company argues that, consistent with Section 94I, it took into account only distribution rates when applying the ten percent cap (Company Brief at 195). The Company maintains such treatment is appropriate because, by its terms, Section 94I applies to "base distribution rate" proceedings and does not reference reconciling mechanisms or other changes in rates (Company Brief at 195; Company Reply Brief at 59). Although NSTAR Gas concedes that customers will experience increases associated with reconciling mechanisms and gas supply costs, the Company argues that this consideration is irrelevant to the ten percent cap prescribed by Section 94I (Company Brief at 195).

According to the Company, the ten percent cap contained in Section 94I acts to mitigate the impact of moving to equalized rates of return for base distribution rates for each customer

[242] The Company claims that its exclusion of residential services in excess of two inches lowered the average residential service cost by $5.23 and caused minor changes in the allocation of service costs (Company Reply Brief at 58, citing RR-AG-1-17).

class (Company Brief at 195, citing Exh. NSTAR-Rebuttal-3, at 2). The Company argues that if increases in reconciling mechanisms and gas supply costs were considered in the Section 94I analysis, distribution companies would never achieve equalized rates of return (Company Reply Brief at 59, citing Exh. AG-4-12). Moreover, the Company contends that reconciling mechanisms have been separated from base distribution rates by the Department because they typically recover costs that have the potential to be volatile or are outside of the Company's control and, therefore, a representative level of such costs cannot be identified on the basis of a test year (Company Reply Brief at 59). Thus, the Company asserts that to include reconciling mechanisms as part of an overall ten percent rate cap would prove unworkable in the long-term (Company Reply Brief at 59). Instead, the Company argues that the correct forum to consider bill impacts for reconciling mechanisms and other costs is in the annual filings for these factors (Company Reply Brief at 59).

In addition, the Company argues that its proposal to cap its base distribution rate increase to each rate class at no greater than 126 percent of the increase to base rates appropriately balances the Department's goals of achieving equalized rates of return and rate continuity (Company Brief at 196, citing Exh. NSTAR-RDC-4, at 10). The Company disputes the Attorney General's contention that the Department has established general guidelines for all companies to restrict overall distribution rate increases to no more than 200 percent of the overall distribution rate increase to each rate class (Company Brief at 195-196; Company Reply Brief at 60). Rather, the Company contends that the application of a cap should be considered on a case-by-case basis (Company Brief at 196; Company Reply Brief at 60). In this regard, the Company claims that the Attorney General's proposal to use a fixed 200 percent cap would reduce rate design to an application of generic formulas without any consideration of the bill impacts present in each individual rate case[243] (Company Reply Brief at 60).

Finally, the Company argues that its proposed higher customer charges are appropriate because they are more efficient, will reduce over- and under-recoveries under decoupling, and will minimize inter-class subsidies (Company Brief at 197; Company Reply Brief at 61). The Company disagrees with the Attorney General's and DOER's recommendation to limit customer charge increases (Company Brief at 196; Company Reply Brief at 60). The Company argues that this recommendation is based on the Department's examination of Bay State Gas Company's cost of service in D.P.U. 13-75 and the results of another company's COSS should have no bearing on setting customer charges in the instant proceeding[244] (Company Brief at 196-197; Company Reply Brief at 60-61).

Further, the Company disagrees with the Attorney General's position that higher customer charges will result in excessive bill increases (Company Brief at 197). Rather, the Company argues that that when customer charges are set below the embedded cost to serve, the rate design is less efficient (Company Brief at 197). In addition, the Company contends that over-reliance on volumetric charges will serve to increase intra-class disparity as higher use

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243 In addition, NSTAR Gas argues that the Attorney General's argument is moot because, based on the Company's revised cost of service calculations the resulting revenue cost allocation differs from the 200 percent approach by only 0.08 percent (Company Brief at 196, <u>citing</u> Attorney General Brief at 76 n.23; Company Reply Brief at 60).

244 Nonetheless, the Company argues that its proposed customer charges are comparable, if not lower, than other Massachusetts gas companies (Company Reply Brief at 61, <u>citing</u> Exh. DPU-2-16). In particular, the Company claims that in D.P.U. 13-75, the Department-approved customer charges fell within 42 to 92 percent of the embedded cost to serve (Company Brief at 196-197). The Company maintains that its proposed customer charges fall within 34 to 71 percent of its embedded cost to serve (Company Brief at 197).

customers will tend to pay a disproportionate share of the cost to serve (Company Brief at 197, citing Exh. NSTAR-Rebuttal-3, at 6).

3. Analysis and Findings

a. Cost Allocation

The Department acknowledges the validity of the concerns raised by the Attorney General with respect to the Company's record keeping regarding services for its residential and small C&I customers as it relates to cost allocation. Without accurate record keeping by the Company costs cannot be appropriately allocated to rate classes. However, the Department declines to impose specific record keeping requirements on the Company at this time. Nonetheless, the Department fully expects that NSTAR Gas, like all other companies, will accurately assign costs to rate classes and will provide the necessary oversight to ensure this is accomplished.

b. Revenue Allocation

i. Section 94I Rate Cap

Section 94I, which was added by Section 20 of an Act Relative to Competitively Priced Electricity in the Commonwealth, St. 2012, c. 209, provides:

> In each base distribution rate proceeding conducted by the [D]epartment under [G.L c. 164, § 94], the [D]epartment shall design base distribution rates using a cost-allocation method that is based on equalized rates of return for each customer class; provided, however, that if the resulting impact of employing this cost allocation method for any [one] customer class would be more than [ten percent], the [D]epartment shall phase in the elimination of any cross subsidies between rate classes on a revenue neutral basis phased in over a reasonable period as determined by the [D]epartment.

The Attorney General and TEC argue that the Department should exercise its discretion and apply the ten percent cap established in Section 94I to all cost increases, including the

Company's proposed $12 million increase in LDAC and gas supply costs, and not just base distribution rates (Attorney General Brief at 72-75; Attorney General Reply Brief at 38; TEC Reply Brief at 4). The Company disagrees and argues that Section 94I applies only to base distribution rate increases (Company Brief at 195). Accordingly, the Company argues that the Department and should not take into account reconciliation mechanisms when applying the ten percent cap (Company Brief at 195).

Costs for certain items adjusted in a base distribution rate case and recovered through reconciling mechanisms generally remain fixed until the next base distribution rate case (e.g., local production and storage, and gas supply acquisition costs). Therefore, a representative level of the cost is recovered through the reconciling mechanism.[245] The intent of Section 94I is to limit the rate increase to any rate class in a base distribution rate proceeding to no more than ten percent. The Department has had an opportunity to apply Section 94I in only two prior rate cases. See D.P.U. 13-90, at 246-248; D.P.U. 13-75, at 355-358. In both cases, less than one percent of the requested rate increase was associated with costs recovered outside of base rates. See D.P.U. 13-90, at 276; D.P.U. 13-75, at 392. As such, in those cases the ten percent cap was applied only to the requested base distribution rate increase. In the instant case, however, the Company's requested increase associated with costs collected through reconciling mechanisms makes up approximately 34 percent of the overall requested increase (see Exh. NSTAR-MFF-4, Sch. MFF-1 (August 21, 2015)). Thus, to exclude these significant cost increases from the application of the cap would mean that some of the Company's rate classes would incur a rate

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245 These costs can be distinguished from costs recovered dollar-for-dollar through reconciling mechanisms (i.e., gas supply costs, pension costs, and supply-related bad debt costs).

increase greater than ten percent (see RR-DPU-24, Att. 1). We find that such a result would be inconsistent with the intent of Section 94I. Accordingly, the Department finds that it is appropriate in this case to include cost increases associated with costs collected through reconciling mechanisms in the application of the ten percent cap.

ii. Rate Class Distribution Rate Cap

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. 03-40, at 384; D.T.E. 02-24/25, at 256; D.T.E. 01-56, at 139; D.P.U. 92-210, at 214. This allocation method satisfies the Department's rate structure goal of fairness. The Department must, however, balance its goal of fairness with its goal of rate continuity. These considerations require the Department to review the revenue requirement for each rate class after the application of the ten percent cap, discussed above, to determine the increase from current revenues.

The Company proposes to cap the rate increase to any rate class at 126 percent of the overall distribution rate increase. The Attorney General's contends that a 200 percent cap is more appropriate for all companies, based on the Department's findings in D.P.U. 13-75. Given the disparities among local distribution companies and their respective rate designs, establishing a cap on a particular rate class' overall rate increase is a case-by-case exercise. Accordingly, the Department declines to establish a general cap applicable to all distribution companies. Instead, the Department will consider the facts of each case to determine an appropriate rate class cap.

In the instant case, the Department has reviewed the changes in total revenue requirement by rate class after the application of the ten percent cap. After the application of the ten percent cap, some rate classes still would receive significant base distribution rate increases (see Schedule 10 below). Accordingly, the Department finds that it is necessary to apply an additional cap such that no rate class shall receive a distribution rate increase greater than 126 percent of the overall distribution rate increase (inclusive of the LDAC factors and gas supply revenues).

Based on the facts of this case, the Department finds that 126 percent is an appropriate cap that meets our rate structure goals of efficiency and continuity by ensuring that: (1) the final rates to each rate class represent or approach the cost to serve that class; (2) the limited level of cost subsidization created by the cap will not unduly distort rate efficiencies; and (3) the magnitude of change to any one class is contained within reasonable bounds. See D.P.U. 13-75, at 362; D.P.U. 09-39, at 422. The Department directs the Company to calculate the 126 percent cap as shown on Schedule 10.

c. Customer Charges

The Company proposes to increase its customer charges, on average, to 58 percent of the full cost of service (Exh. NSTAR-RDC-4, at 13). The Attorney General, DOER and TEC argue that the Company's proposed customer charge increases are too high and fail to consider the potential adverse bill impacts to low-use customers within each rate class (see Attorney General Brief at 77; DOER Brief at 7-8; TEC Reply Brief at 6). To address these concerns, the Attorney General recommends that the Department limit the customer charge increase to 25 percent for rates G-43 and G-53, and to 15 percent for all other rate classes (Attorney General Brief at 77-78).

In setting customer charges, the Department must balance the competing rate structure goals of: (1) efficiency (i.e., setting the customer charge to recover its cost to serve); and (2) rate continuity. D.P.U. 10-55, at 561. The Department acknowledges the arguments raised by the Attorney General, DOER, and TEC with respect to the Company's proposed customer charges. We decline, however, to adopt the Attorney General's recommendation to limit the customer charges to a specific percentage increase. Rather, the Department finds that it is appropriate to evaluate the proposed customer charges on a rate class by rate class basis. See D.P.U. 13-90, at 250; D.P.U. 13-75, at 363; D.P.U. 10-114, at 363; D.P.U. 10-55, at 562. The Department evaluates the Company's proposed customer charges in Section XIII.F below.

d. Other Issues

The Company proposes to eliminate block rates and seasonally differentiated rates for all residential and low-use C&I rate classes but to continue the seasonal rate differential for high- and medium-use C&I rate classes (see Exh. NSTAR-RDC-4, at 16-17). No party commented on the Company's proposal. The Company's proposal to eliminate block rates is consistent with rate designs that recently have been approved by the Department for other gas companies. See D.P.U. 13-75, at 358-361; D.P.U. 12-25, at 468-469.[246] Further, we find that the Company's proposal to eliminate seasonally differentiated rates for all residential and low-use

[246] In particular, we note that in D.P.U. 12-25, at 468-469, the Department stated that it was not fully persuaded that an inclining block rate structure continue to accomplish end-use energy efficiency, for at least three reasons: (1) the difference between the head and tail block rates generally are small; (2) inclining block rates, as designed to date, apply only to the distribution charge, which is a relatively small portion of the entire bill; and (3) customers currently have no information as to when they are about to hit the tail block, and thus do not have a signal to help them conserve. D.P.U. 12-25, at 468-469. The Department eliminated Bay State Gas Company's inclining block rate structure a year later in that company's next rate case. D.P.U. 13-75, at 358-361.

C&I rate classes and continue the seasonal rate differential for high- and medium-use C&I rate classes is acceptable. The results of the COSS for the residential and low-use C&I rate classes were contrary to appropriate rate structure i.e., the off-peak period volumetric rates were higher than the peak period volumetric rates, and as such, would not send the proper price signals, whereas, the results of the COSS for the high- and medium use C&I rate classes were consistent with appropriate rate structure (Exh. NSTAR-RDC-4, at 16).

In addition, the Company proposes to continue the flat volumetric rate for all C&I rate classes (see Exh. NSTAR-RDC-4, at 16-17). In our rate-by-rate analysis below, the Department determines the appropriate volumetric charge for each rate class. When setting the rates for the individual rate classes, the Company shall truncate the volumetric rates at four decimal places to ensure that such rates are designed to collect no more than the allowed revenue requirement. See D.P.U. 13-75, at 361; D.P.U. 10-70, at 333.

NSTAR Gas also proposes to establish the delivery service rates for its low income customers such that customers on rates R-2 and R-4 receive a 25 percent discount off of the total bill (Exh. NSTAR-RDC-4, at 12). No party commented on the Company's proposal to increase the low income discount.

Pursuant to G.L. c. 164, § 1F(4)(i) ("Section 1F"), distribution companies must provide discounted rates for low income customers comparable to the low income discount received on the total bill for rates in effect prior to March 1, 1998. See Expanding Low Income Consumer Protections and Assistance, D.P.U. 08-4, at 36 (2008). The Company's current low income discounts for the R-2 and R-4 rate classes are 18.8 percent and 18.4 percent, respectively

(Exh. NSTAR-RDC-4, at 12). These discounts are at the levels that were in effect as of March 1, 1998. See Low Income Discount Rate, D.P.U. 10-41 through 10-48, at 26 (2010).

The Company seeks to increase the low income discount beyond the level required by Section 1F. The Company's proposed 25 percent discount is consistent with the low income discount level that the Department has approved for other distribution companies. See D.P.U. 12-25, at 473-474; D.P.U. 11-01/11-02, at 462; D.P.U. 10-114, at 366-367; D.P.U. 10-55, at 564. In those instances, the Department found that it was appropriate to establish a low income discount of 25 percent of the total bill because it provided a significant benefit to low-income customers as compared to a modest increase in the bill impacts of non-low income customers and will result in administrative efficiencies. D.P.U. 12-25, at 473-474; D.P.U. 11-01/11-02, at 462; D.P.U. 10-114, at 366-367; D.P.U. 10-55, at 564. In the instant case, we have reviewed the effects of increasing the low-income discount to 25 percent and have determined that the overall bill impacts demonstrate a significant benefit to low income customers as compared to a modest increase in the bill impacts of non-low income customers. Accordingly, the Department approves the Company's proposal to set the low income discount for rates R-2 and R-4 at 25 percent of the total bill.

Further, the Company proposes to close rate T-1 and transfer six of its seven remaining customers to rate G-53, and one customer to rate G-43. No party commented on the Company's proposal. As the Company's rates will be unbundled pursuant to the directives in the instant Order, there no longer remains a need for a transportation-only rate class. Therefore, the Department approves the Company's proposal to close rate T-1.

The Company also proposes to close rate S-1. No party commented on the Company's proposal. There no longer are any customers taking service under this rate (Exh. NSTAR RDC 4, at 19). Accordingly, the Department approves the Company's proposal to close rate S-1.

Finally, the Company proposes to discontinue its default service demand charge adjustment and default service energy credit adjustment for its rate G-53 customers. No party commented on the Company's proposal. The default service demand charge and default service energy credit adjustments were introduced as transitional rate design elements in 1998 when the Company unbundled rates on a revenue neutral basis (Exh. NSTAR-RDC-4, at 18). The Department finds that these adjustments are no longer necessary in an unbundled environment. Accordingly, the Department approves the Company's proposal to discontinue the default service demand charge adjustment and default service energy credit adjustment for rate G-53.

F. Rate by Rate Analysis

1. Introduction

The Company's rate structure consists of four residential rate classes and six C&I rate classes. The residential rate classes are differentiated based on whether or not the customer's gas use includes gas space heating equipment and whether the customer receives a subsidized rate. The C&I rate classes are set based on whether the customer has a high or low load factor and whether their gas use is high, medium, or low. The rate design for each rate class is discussed below.

2. Rates R-1 (Residential Non-Heat), R-3 (Residential Heating), R-2 (Low Income Non-Heat), and R-4 (Low Income Heating)

a. Introduction

Rate R-1 is available to residential customers whose gas use is not from gas space heating equipment (Exh. NSTAR-RDC-6, at 145 (proposed M.D.P.U. No. 420A)). Rate R-3 is available to all residential customers whose gas use includes gas space heating equipment (Exh. NSTAR-RDC-6, at 149 (proposed M.D.P.U. No. 422A)).

Rate R-2 is a subsidized rate that is available to residential customers receiving any means-tested public benefit program or are eligible for the low income home energy assistance program or its successor program, for which eligibility does not exceed 60 percent of the median income in Massachusetts based on a household's gross income or other criteria approved by the Department, and receive gas service at single locations for domestic non-heating purposes in private dwellings and individual apartments (Exh. NSTAR-RDC-6 at 147, 151 (proposed M.D.P.U. No. 421D)). Rate R-4 is a subsidized-rate with the same eligibility criteria as rate R-2 except that it is available to residential customers that receive gas service at single locations for domestic heating purposes in private dwellings and individual apartments (Exh. NSTAR-RDC-6 at 151-152 (proposed M.D.P.U. No. 423D)).

Rate R-2 has the same delivery service rates as rate R-1, and rate R-4 has the same delivery service rates as rate R-3 (RR-DPU-18, Att. (a) at 13-16). As discussed in Section XIII.E.3.d above, the Department approved NSTAR Gas proposal that customers taking service on rates R-2 and R-4 receive a 25 percent discount off the total bill, including the total charges for rates R-1 and R-3, respectively (Exh. NSTAR-RDC-4, at 12-13).

NSTAR Gas' current and proposed rates R-1, R-2, R-3, and R-4 distribution charges are as shown in the following table:[247]

	Current		**Proposed**
Rates: R-1 & R-2	**Peak**	**Off-Peak**	
Customer Charge	$6.50/month		$9.50/month
Distribution Charge ($/Therm)	$.6871/therm for first 20 therms	$.6225/therm for first ten therms	$0.5176
	$.4258/therm over 20 therms	$.3612/therm over ten therms	
Rates: R-3 & R-4			
Customer Charge	$6.50/month		$9.50/month
Distribution Charge ($/Therm)	$.5410/therm for first 50 therms		$0.3963
	$.2466/therm over 50 therms		

b. Analysis and Findings

According to the Company's COSS, the existing embedded customer charge for rates R-1 and R-3 are $26.37 and $26.83 per month, respectively (see RR-DPU-18, Att. (a) at 6)). Based on a review of embedded costs and the seasonal and annual bill impacts on customers, the Department finds that a monthly customer charge of $8.50 for rates R-1 and R-3 best meets our rate design goals and objectives. NSTAR Gas shall set the volumetric rate for rates R-1 and R-3 to recover the remaining class revenue requirement approved in this Order. Finally, the Department approves the Company's proposal to set the rate R-2 and rate R-4 charges the same as the rate R-1 and rate R-3 charges, respectively.

247 Source: RR-DPU-18, Att. (a) at 13-16.

3. Rate G-41 (C&I Small Annual Use/Low Load Factor)

a. Introduction

Rate G-41 is available to C&I customers who consume less than 10,000 therms of gas per year and whose consumption of gas during the off-peak season (i.e., May through October) is less than 30 percent of total consumption during the same calendar year (Exh. NSTAR-RDC-6, at 153-154 (proposed M.D.P.U. No. 430A)). NSTAR Gas' current and proposed rate G-41 customer and distribution charges are shown in the following table:[248]

	Current		**Proposed**
Rate: G-41	**Peak**	**Off-Peak**	
Customer Charge	$15.00/month		$20.00/month
Distribution Charge ($/Therm)	$0.2529	0.1712	$0.2712

b. Analysis and Findings

According to the Company's COSS, the embedded customer charge for rate G-41 is $36.78 (see RR-DPU-18(a), Att. (a) at 6)). Based on a review of embedded costs and the seasonal and annual bill impacts on customers, the Department finds that a monthly customer charge of $19.00 for rate G-41 best meets our rate design goals and objectives. NSTAR Gas shall set the volumetric rate for rate G-41 to recover the remaining class revenue requirement approved in this Order.

248 Source: RR-DPU-18, Att. (a) at 17.

4. Rate G-42 (C&I Medium Annual Use/Low Load Factor)

a. Introduction

Rate G-42 is available to C&I customers who consume at least 10,000 therms but less than 100,000 therms per year and whose consumption of gas during the off-peak season (i.e., May through October) is less than 30 percent of total consumption during the same calendar year (Exh. NSTAR-RDC-6, at 155-156 (proposed M.D.P.U. No. 431A)). NSTAR Gas' current and proposed rate G-42 customer and distribution charges are shown in the following table:[249]

	Current		Proposed	
Rate: G-42	**Peak**	**Off-Peak**	**Peak**	**Off-Peak**
Customer Charge	$30.00/month		$45.00/month	
Distribution Charge ($/Therm)	$0.2291	0.1113	$0.1999	$0.1361

b. Analysis and Findings

According to the Company's COSS, the embedded customer charge for rate G-42 is $92.20 (see RR-DPU-18, Att. (a) at 6). Based on a review of embedded costs and the seasonal and annual bill impacts on customers, the Department finds that a monthly customer charge of $40.00 for rate G-42 best meets our rate design goals and objectives. NSTAR Gas shall set the volumetric rate for rate G-42 to recover the remaining class revenue requirement approved in this Order and to maintain the ratio of peak to off-peak revenue requirement proposed by the Company.

249 Source: RR-DPU-18, Att. (a) at 18.

5. Rate G-43 (C&I Large Annual Use/Low Load Factor)

a. Introduction

Rate G-43 is available to C&I customers who consume at least 100,000 therms per year and whose consumption of gas during the off-peak period (i.e., May through October) is less than 30 percent of total consumption during the same calendar year (Exh. NSTAR-RDC-6, at 157-158 (proposed M.D.P.U. No. 432A)). NSTAR Gas' current and proposed rate G-43 customer and distribution charges are shown in the following table:[250]

	Current		Proposed	
Rate: G-43	**Peak**	**Off-Peak**	**Peak**	**Off-Peak**
Customer Charge	$100.00/month		$157.00/month	
Distribution Charge ($/Therm)	$0.2158	0.0828	$0.1873	$0.0981

b. Analysis and Findings

According to the Company's COSS, the embedded customer charge for rate G-43 is $307.46 (see RR-DPU-18, Att. (a) at 6). Based on a review of embedded costs and the seasonal and annual bill impacts on customers, the Department finds that a monthly customer charge of $141.00 for rate G-43 best meets our rate design goals and objectives. NSTAR Gas shall set the volumetric rate for rate G-43 to recover the remaining class revenue requirement approved in this Order and to maintain the ratio of peak to off-peak revenue requirement proposed by the Company.

250 Source: RR-DPU-18, Att. (a) at 19.

6. Rate G-51 (C&I Small Annual Use/High Load Factor)

a. Introduction

Rate G-51 is available to C&I customers who consume less than 10,000 therms of gas per year and whose consumption of gas during the off-peak period (i.e., May through October) is 30 percent or more of total consumption during the same calendar year (Exh. NSTAR-RDC-6, at 159-160 (proposed M.D.P.U. No. 433A)). NSTAR Gas' current and proposed rate G-51 customer and distribution charges are shown in the following table:[251]

	Current		Proposed	
Rate: G-51	**Peak**	**Off-Peak**	**Peak**	**Off-Peak**
Customer Charge	$15.00/month		$20.00/month	
Distribution Charge ($/Therm)	$0.2315	0.1612	$0.2379	$0.1739

b. Analysis and Findings

According to the Company's COSS, the embedded customer charge for rate G-51 is $39.62 (see RR-DPU-18, Att. (a) at 6). Based on a review of embedded costs and the seasonal and annual bill impacts on customers, the Department finds that a monthly customer charge of $19.00 for rate G-51 best meets our rate design goals and objectives. NSTAR Gas shall set the volumetric rate for rate G-51 to recover the remaining class revenue requirement approved in this Order.

[251] Source: RR-DPU-18, Att. (a) at 20.

7. Rate G-52 (C&I Medium Annual Use/High Load Factor)

a. Introduction

Rate G-52 is available to C&I customers who consume at least 10,000 therms but less than 100,000 therms of gas per year and whose consumption of gas during the off-peak period (i.e., May through October) is 30 percent or more of total consumption during the same calendar year (Exh. NSTAR-RDC-6, at 161-162 (proposed M.D.P.U. No. 434A)). NSTAR Gas' current and proposed rate G-52 customer and distribution charges are shown in the following table:[252]

	Current		**Proposed**	
Rate: G-52	**Peak**	**Off-Peak**	**Peak**	**Off-Peak**
Customer Charge	$30.00/month		$45.00/month	
Distribution Charge ($/Therm)	$0.1884	0.0818	$0.1891	$0.0988

b. Analysis and Findings

According to the Company's COSS, the embedded customer charge for rate G-52 is $77.34 (see RR-DPU-18, Att. (a) at 6). Based on a review of embedded costs and the seasonal and annual bill impacts on customers, the Department finds that a monthly customer charge of $40.00 for rate G-52 best meets our rate design goals and objectives. NSTAR Gas shall set the volumetric rate for rate G-52 to recover the remaining class revenue requirement approved in this Order and to maintain the ratio of peak to off-peak revenue requirement proposed by the Company.

252 Source: RR-DPU-18, Att. (a) at 21.

8. Rate G-53 (C&I Large Annual Use/High Load Factor)

a. Introduction

Rate G-53 is available to C&I customers who consume at least 100,000 therms of gas per year and whose consumption of gas during the off-peak season (i.e., May through October) is 30 percent or more of total consumption during the same calendar year (Exh. NSTAR-RDC-6, at 163-164 (proposed M.D.P.U. No. 435A)). To calculate the proposed volumetric, the Company subtracted the proposed customer revenues from the target revenue requirement and then divided the result by test year billing demand (Exh. NSTAR-RDC-4, at 24).

NSTAR Gas' current and proposed rate G-53 customer and distribution charges are shown in the following table:[253]

	Current		**Proposed**	
Rate: G-53	**Peak**	**Off-Peak**	**Peak**	**Off-Peak**
Customer Charge	$100.00/month		$350.00/month	
Distribution Demand Charge ($/Therm)	$2.44	$1.07	$2.80 Demand rate	$1.29 Demand rate

b. Analysis and Findings

According to the Company's COSS, the embedded customer charge for rate G-53 is $475.82 (see RR-DPU-18, Att. (a) at 6)). Based on a review of embedded costs and the seasonal and annual bill impacts on customers, the Department finds that a monthly customer charge of $237.00 for rate G-53 best meets our rate design goals and objectives. NSTAR Gas shall set the

253 Source: RR-DPU-18, Att. (a) at 24.

volumetric rate for Rate G-53 to recover the remaining class revenue requirement approved in this Order and to maintain the ratio of peak to off-peak revenue requirement proposed by the Company.

G. Farm Discount Rider

1. Introduction

The Farm Discount Rider applies to customers taking service under any of the Company's retail distribution service rates who are engaged in the business of agriculture or farming as defined by G.L. c. 128, § 1A (Exh. NSTAR-RDC-6, at 166 (proposed M.D.P.U. No. 450A)). The Company applies a credit in the amount of ten percent to the retail delivery service charges, which include LDAC charges and default service charges, if applicable (Exh. NSTAR-RDC-6, at 166 (proposed M.D.P.U. No. 450A)). The Company proposes to apply the ten percent credit to the revenue decoupling adjustment charge (Exh. NSTAR-RDC-6, at 166 (proposed M.D.P.U. No. 450A)). No party commented on the Company's proposal.

2. Analysis and Findings

In Section III above, the Department approved the Company's proposed revenue decoupling mechanism, with modification. The Department finds that the Company's proposed adjustment to the Farm Discount Rider is in consistent with 220 C.M.R. § 11.04(6)(a).[254] Accordingly, we approve the Company's Farm Discount Rider adjustment, as proposed.

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254 Pursuant to 220 C.M.R. § 11.04(6)(a):

> Each [d]istribution [c]ompany shall provide [c]ustomers who meet the eligibility requirements for being engaged in the business of agriculture or farming, as defined in [G.L. c. 128, § 1A], a [ten percent] reduction in the rates to which such [c]ustomers would otherwise be subject. Each [d]istribution [c]ompany shall allocate to other rate classes, as part of a general rate case, the revenue deficiency

H. Service Fees

1. Introduction

The Company proposes to increase one of its existing fees and to impose two new fees. The Department has found that for various ancillary services, such as meter testing, returned checks, and cross-connection inspection, the associated fees must be based on the costs that the company actually incurred associated with these functions. D.P.U. 08-35, at 58; D.P.U. 08-27, at 46; D.P.U. 95-118, at 84; Whitinsville Water Company, D.P.U. 89-67, at 4-5 (1989); D.P.U. 956 at 62. Each of the Company's proposed fees is addressed below.

2. Account Activation Fee

a. Introduction

The Company proposes to increase its existing account reactivation fee from $12.00 to $75.16[255] (Exhs. NSTAR-RDC-1, at 18-19; NSTAR-RDC-4, at 35). The Company asserts that while the increase in the fee is significant, the proposed fee is comparable to fees recently approved by the Department for other gas companies (Exh. NSTAR-RDC-1, at 19; DPU-2-12, Att.).

The Company states that during 2013, it collected $33,684 in account restoration fees from 2,807 accounts (Exhs. NSTAR-RDC-1, at 18; DPU-2-11, Att. (d)). The Company calculates that the fee increase would yield an additional $177,290 in revenues

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resulting from the farm discount using an allocation method approved by the Department for the [d]istribution [c]ompany.

255 The Company states that its proposed $75.16 account reactivation fee is comprised of: (1) $65.79 in labor based on its 2014 contractual rate and assumption that each reactivation will take one hour including travel; and (2) $9.37 in vehicle expense based on an hourly rate at 2014 budgeted costs (Exh. DPU-2-12, Att.).

(Exh. NSTAR-RDC-1, at 19, NSTAR-RDC-2, Sch. RDC-5; DPU-2-11, Atts. (a), (d)). No party commented on the Company's proposal.

b. Analysis and Findings

The Company proposes to increase its existing account reactivation fee from $12.00 to $75.16. The Department has reviewed the Company's supporting calculations and assumptions, and finds that an account reactivation fee of $75.00[256] is reasonable as it is based on the costs NSTAR Gas incurs associated with this function (Exhs. DPU-2-11(d) at 2; DPU-2-12, Att.). The Department further finds that the Company has correctly incorporated the additional revenues associated with the fee increase as a revenue credit in its proposed cost of service (Exhs. NSTAR-RDC-1, at 18-19; NSTAR-RDC-2, Sch. RDC-5). Accordingly, the Department approves an account reactivation fee of $75.00.

3. Sales Tax Abatement Fee

a. Introduction

The Company proposes to introduce as a new fee, a sales tax abatement fee of $55.14. According to the Company, the sales tax abatement fee is intended to cover the administrative cost incurred by the Company's corporate accounting department to refund sales taxes at the request of customers who had not provided sales tax exemption certificates to the Company in a timely manner[257] (Exhs. NSTAR-RDC-4, at 35; DPU-4-11).

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256 For administrative ease, the Department sets the fee to the nearest dollar. See Fitchburg Gas and Electric Light Company, D.P.U. 11-82-A/11-97/D.P.U. 12-70-A/D.P.U. 13-134-A at 9 n.17 (2014); Fitchburg Gas and Electric Light Company, D.P.U. 12-118-A at 2 n.3 (2014); Statewide Towing Association, D.P.U. 97-37, at 11 n.5 (1997).

257 Pursuant to G.L. c. 64H, § 6, non-residential gas customers are liable for sales and use taxes, subject to a variety of exemptions. In order to qualify for exemption from sales

The Company states that during 2013, it processed 20 sales tax abatement requests and it processed another 64 such requests in 2012 (Exh. NSTAR-RDC-4, at 35). The Company's proposed sales tax abatement fee is comprised of costs related to: (1) the calculation of the abatement amount; (2) the review and approval of the abatement request; and (3) various reporting requirements[258] (Exh. DPU-4-11). No party commented on the Company's proposal.

b. Analysis and Findings

No Massachusetts gas or electric distribution company currently collects a sales tax abatement fee. The costs that the Company identifies as related to sales tax abatements are administrative in nature and annually recurring (see Exhs. NSTAR-RDC-4, at 35; DPU-4-11, Att. (a)). Accordingly, the costs of processing sales tax abatements are already embedded in the Company's cost of service. Therefore, we find that including a separate fee to recover the administration of sales tax abatements would amount to double recovery of such costs. Accordingly, the Department denies the Company's request to implement a sales tax abatement fee.

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and use taxes, eligible customers must submit a sales tax exemption certificate to the Company. G.L. c. 64H, § 8.

258 The Company identifies the costs associated with the proposed sales tax abatement fee as follows: (1) $45.76 to calculate the actual abatement; (2) $2.42 to incorporate the abatement request in the Company's internal reporting; (3) $1.34 for the actual abatement approval; (4) $3.79 to include the abatement in the Company's tax period reports; and (5) $1.82 to incorporate the abatement in the Company's reports to the Massachusetts Department of Revenue (Exh. DPU-4-11, Att. (d)).

4. Meter Diversion Fee

a. Introduction

The Company proposes to introduce a new fee, a meter diversion fee of $250 (Exhs. NSTAR-RDC-4, at 35). The Company proposes to levy the charge whenever it determines that a customer has received unmetered service as a result of any tampering with the meter or other Company equipment (Exhs. NSTAR-RDC-4, at 35; DPU-4-11). The Company states that this charge is intended to be in addition to any re-billing of the customer that may occur, including any late payment charges imposed on the customer (Exh. DPU-4-11). The Company reports that between 2010 and 2013, it investigated 186 cases of suspected meter diversion and confirmed theft of services in 66 of these cases (Exhs. NSTAR-RDC-4, at 35; DPU-4-11, at 1).

According to NSTAR Gas, while meter tampering and theft of utility services is a violation of Massachusetts law, it can be costly to pursue civil or criminal complaints in every case (Exh. DPU-4-11). The Company states that the proposed meter diversion fee is an additional measure to deter theft of service (Exh. DPU-4-11). The Company asserts that given the large number of confirmed thefts, the implementation of a meter diversion fee is necessary to send a strong message to customers that energy theft is a serious issue with both civil and criminal ramifications (Exh. DPU-4-11, at 2). Finally, the Company notes that the proposed $250 meter diversion fee is similar to fees authorized for utilities in other jurisdictions (e.g., Connecticut, Florida, Georgia, Indiana, Iowa, Ohio, and North Dakota) (Exh. DPU-4-11, Att. (b)). No party commented on the Company's proposal.

b. Analysis and Findings

The Company proposes a meter diversion fee as a deterrent for meter tampering and theft of service. The Department has allowed investor owned water companies to levy penalties for water use restrictions during a state of water supply conservation or water supply emergency. See e.g., Agawam Spring Water Company, D.P.U. 13-163, at 111 (2014); Assabet Water Company, M.D.P.U. No. 4, Supplement 1, at 2; Plymouth Water Company, M.D.T.E. No. 8, Original Sheet No. 15. The Department has not, however, approved a meter diversion fee for any gas, electric, or water company subject to our jurisdiction.

We expect that the Company, in discharging its duty as a public utility, will pursue all reasonable efforts to prevent meter diversion or theft of services. In this regard, we note that G.L. c. 164, § 127A provides civil remedies for these infractions, including treble damages, the value of the unauthorized amount of gas used, and the cost of equipment repair and replacement. While we acknowledge that litigation can be time consuming and expensive, NSTAR Gas' proposal will do little to deter unscrupulous ratepayers and it may provide a disincentive for the Company to forego more meaningful measures to recover costs associated with meter diversion of theft of services.[259] As such, we decline to approve the Company's proposal.

XIV. TARIFF CHANGES

A. Introduction

The Company proposes certain changes to the following tariffs: (1) Terms and Conditions, proposed M.D.P.U. No. 400B; (2) Seasonal Cost of Gas Adjustment Clause, proposed M.D.P.U. No. 401C; (3) Local Distribution Adjustment Clause, proposed

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[259] We note that litigation expenses of this nature are recoverable in the context of the Company's overall outside legal fees expense or regulatory expense.

M.D.P.U. No. 402G; (4) PAM-1, proposed M.D.P.U. No. 406B; (5) Residential Assistance Adjustment Clause, proposed M.D.P.U. No. 407D; (6) Revenue Decoupling Adjustment Clause, proposed M.D.P.U. No. 409; (7) Rate G-53, proposed M.D.P.U. 435A; (8) Interim Transportation Charge Rider, proposed M.D.P.U. No. 437A; and (9) Dual Fuel Special Provision, proposed M.D.P.U. No. 451A (Exh. NSTAR-RDC-4, at 33-43). Several of the proposed changes are associated with issues that are the subject of findings in other sections of this Order (see, e.g., Sections III, XIII.D). Therefore, the Company shall submit revised tariffs consistent with those findings. The remaining tariff changes, either proposed by the Company or required by the Department, are discussed below.

B. Exogenous Cost Adjustment Provision

1. Introduction

The Company's original filing contains a proposed provision in the LDAC tariff entitled "Exogenous Cost Adjustment" (Exh. NSTAR-RDC-6, at 120-121 (proposed M.D.P.U. No. 402G § 10.0)). This proposed tariff provision was intended to serve as the basis for the recovery of incremental property tax expenses incurred as a result of a new property valuation adopted by certain municipalities, as described above in Section IX (see Exhs. NSTAR-MFF-1, at 71-75; NSTAR-RDC-4, at 37; DPU-18-3; Tr. 9, at 839). During the course of the proceeding, the Company proposed the EPTA tariff provision, which is a more detailed provision within the LDAC to address the recovery of incremental property tax expenses and is discussed above in Section IX (Exh. DPU-18-3, Att.). However, the Company also proposes to retain the

Exogenous Cost Adjustment provision to address other types of exogenous costs allowable under the Merger Settlement that might arise prior to December 31, 2015 (Tr. 9, at 839-840).[260]

2. Positions of the Parties

The Attorney General argues that the Department has allowed provisions similar to the proposed Exogenous Cost Adjustment provision only in connection with rate freezes or other fixed term rate plans that impose restrictions on seeking base rate relief under G.L. c. 164, § 94 (Attorney General Brief at 84, citing D.P.U. 10-170-B; D.P.U. 96-50 (Phase I)). Further, she claims that the Company has not provided any analysis or testimony regarding the application of such a provision in the context of a proposed decoupling mechanism (Attorney General Brief at 84). The Attorney General states that the Company concedes that it does not foresee a need for the proposed provision (Attorney General Brief at 84, citing Tr. 9, at 817-818). For these reasons, the Attorney General recommends that the Department reject the proposed Exogenous Cost Adjustment provision (Attorney General Brief at 84). She asserts that if the Company ultimately incurs exogenous costs that materially affect earnings, it can seek to recover those costs through a rate case filing (Attorney General Brief at 84).

The Company provides no additional argument in support of its proposed Exogenous Cost Adjustment provision (see Company Brief at 175 n.32). No other party commented on the Company's proposal.[261]

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260 The Merger Settlement addresses exogenous cost recovery at Art. II (5).

261 The Attorney General and the Company address the EPTA proposal in Section IX above.

3. Analysis and Findings

The Company concedes that it does not anticipate seeking recovery of any exogenous costs pursuant to the Merger Settlement, other than those associated with incremental property tax assessments, as discussed in Section IX, above (Tr. 9, at 817-818, 841). Consistent with our findings above in Section IX, we conclude that if the Company believes that it is entitled to any exogenous costs pursuant to the Merger Settlement, it should file a separate petition to recover those costs. Any proposed changes to the LDAC tariff will be addressed at that time. Accordingly, as part of its compliance filing, the Company shall file a revised LDAC that excludes the proposed Exogenous Cost Adjustment provision (Exh. NSTAR-RDC-6, at 120-121 (proposed M.D.P.U. No. 402G § 10.0)).

C. Annual Non-Firm Distribution Credit Factor

1. Introduction

The Company's original filing contains a provision in the LDAC tariff entitled "Annual Non-Firm Distribution Credit Factor" (Exh. NSTAR-RDC-6, at 123-124 (proposed M.D.P.U. No. 402G § 11.2)). The provision provides a method of calculating a ratepayer credit associated with margins earned by the Company in providing non-firm distribution service (Exh. NSTAR-RDC-6, at 123-124 (proposed M.D.P.U. No. 402G § 11.2)). Pursuant to the provision, any margins earned in excess of an annually adjusted threshold are divided between firm customers and the Company under a 75/25 percent margin-sharing allocation (see Exh. NSTAR-RDC-6, at 123-124 (proposed M.D.P.U. No. 402G § 11.2)). See also Investigation into Margin Sharing, D.P.U. 10-62-A at 20 (2013); Interruptible Transportation, D.P.U. 93-141-A at 63-64 (1996). During the course of the proceedings, the

Company revised this provision to update the margin-sharing allocation to 90/10 percent, consistent with the Department's findings in D.P.U. 10-62-A at 36 (Tr. 14, at 1173-1176; RR-DPU-26, Att.). No parties commented on this proposed tariff provision.

2. Analysis and Findings

After review, the Department finds that the Annual Non-Firm Distribution Credit Factor provision of the proposed LDAC tariff requires further revision. Although the Company appropriately updated the margin-sharing allocation, the proposed provision includes the use of an earned margin threshold to trigger the 90/10 margin-sharing allocation (RR-DPU-26, Att.). The Department has eliminated the use of a threshold from its margin-sharing policy. D.P.U. 10-62-A at 24-26. Accordingly, the Department directs the Company, as part of its compliance filing, to revise the Annual Non-Firm Distribution Credit Factor provision of its LDAC tariff so that 90 percent of non-firm distribution margins are credited to customers irrespective of any earned margin threshold.

D. LDAC Tariff – GSEP Provision

The Company proposes amend its LDAC tariff to include provisions related to its GSEP (Exhs. NSTAR-RDC-4, at 37; NSTAR-RDC-6, at 15-27 (Supp.) (proposed M.D.P.U. No. 402G § 8.0)). No party addressed the Company's proposed tariff changes.

The Department finds that it is more appropriate to review the proposed GSEP provisions in D.P.U. 14-135, the docket where the GSEP was approved. Accordingly, as part of its compliance filing in this proceeding, the Company shall file a revised LDAC tariff that excludes the proposed GSEP provisions. Further, the Company is directed to submit a revised exemplar LDAC tariff including the proposed GSEP provisions in D.P.U. 14-135 for review.

E. Remaining Tariff Provisions

The Company proposes changes to the following tariffs that are not addressed above or elsewhere in this Order: (1) Terms and Conditions, proposed M.D.P.U. No. 400B; (2) Seasonal Cost of Gas Adjustment Clause, proposed M.D.P.U. No. 401C; (3) PAM-1, proposed M.D.P.U. No. 406B; (4) Interim Transportation Charge Rider, proposed M.D.P.U. No. 437A; and (5) Dual Fuel Special Provision, proposed M.D.P.U. No. 451A (Exh. NSTAR-RDC-4, at 33-43). No party the Company's proposed changes.

We find that the Company's proposed changes with respect to the foregoing tariffs are reasonable and, therefore, we approve the proposed changes. The Company is directed to file revised tariffs with its compliance filing reflecting the proposed changes.

XV. SCHEDULES

A. Schedule 1 - Revenue Requirements and Calculation of Revenue Increase

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
COST OF SERVICE				
Total O&M Expense	73,255,883	(1,791,893)	(1,035,414)	70,428,577
Uncollectible O&M Due to Increase	776,914	(245,413)	(229,376)	302,125
Depreciation & Amortization	31,790,318	(1,157,391)	(2,210,143)	28,422,784
Taxes Other Than Income Taxes	19,427,378	(73,042)	(1,026,175)	18,328,161
Income Taxes	18,363,110	(1,116,458)	(1,200,707)	16,045,946
Return on Rate Base	40,710,140	(2,353,403)	(1,662,330)	36,694,407
Total Cost of Service	184,323,743	(6,737,599)	(7,364,144)	170,221,999
OPERATING REVENUES				
Total Operating Revenues	150,418,093	3,972,584	0	154,390,677
Revenue Deficiency	33,905,650	(10,710,183)	(7,364,144)	15,831,322

Note: Numbers may not add due to rounding.

B. Schedule 2 - Operations and Maintenance Expenses

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Test Year O&M Expense	71,453,078	(117,676)	0	71,335,402
ADJUSTMENTS TO O&M EXPENSE:				
Advertising Expense	(72,827)	0	0	(72,827)
Uncollectibles Expense	(1,410,919)	0	(133,152)	(1,544,071)
Computer Services	133,508	0	0	133,508
Dues And Memberships	(14,012)	(17,372)	0	(31,384)
Employee Benefits	1,695,034	72,057	(763,641)	1,003,450
Insurance Expense And Injuries & Damages	(404,295)	(532,698)	0	(936,993)
Payroll Expense	3,079,307	(39,070)	0	3,040,237
Variable Compensation	(960,337)	4,039	0	(956,298)
Postage	47,626	0	(4,686)	42,940
Rate Case Expense	229,098	(39,391)	(41,540)	148,167
Regulatory Assessments	13,232	4,566	0	17,798
Shareholder Services	0	0	(88,279)	(88,279)
Leases Expense	45,664	0	0	45,664
Inflation Allowance	1,238,312	(515,727)	(4,116)	718,470
Home Heating Protection Plan (HHPP)	(1,816,586)	(610,621)	0	(2,427,207)
Total Other O&M Expenses	1,802,805	(1,674,217)	(1,035,414)	(906,825)
Total O&M Expense	**73,255,883**	**(1,791,893)**	**(1,035,414)**	**70,428,577**

Note: Numbers may not add due to rounding.

C. Schedule 3 - Depreciation and Amortization Expenses

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Depreciation Expense				
Depreciation & General Plant Amortization Expense	27,019,305	13,165	(1,276,690)	25,755,780
Amortizaton Expense				
Goodwill	2,898,000	0	(188,664)	2,709,336
Property Sales	(184,834)	(152,400)	(3,014)	(340,248)
Hardship Receivables	576,410	0	0	576,410
ASC 740 Regulatory Asset	976,682	0	(773,931)	202,751
Merger Costs to Achieve	484,755	0	0	484,755
Deferred Repairs Study Costs	20,000	0	(20,000)	0
Customer Credit - HHPP Gain	0	(1,018,156)	52,156	(966,000)
Total Depreciation & Amortization Expenses	**31,790,318**	**(1,157,391)**	**(2,210,143)**	**28,422,784**

Note: Numbers may not add due to rounding.

D. Schedule 4 - Rate Base and Return on Rate Base

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Utility Plant in Service	1,006,025,082	(2,177,603)	(6,685,376)	997,162,103
LESS:				
Reserve for Depreciation	347,367,699	4,432,324	(188,215)	351,611,808
Reserve for Amortization	1,645,594	(126,463)	(68,258)	1,450,873
Net Utility Plant in Service	657,011,789	(6,483,464)	(6,428,903)	644,099,422
ADDITIONS TO PLANT:				
Cash Working Capital	7,699,297	(162,326)	(179,443)	7,357,528
ASC 740 (net)	3,916,993	1	0	3,916,994
Materials and Supplies	2,339,054	(2,523)	0	2,336,531
Total Additions to Plant	13,955,344	(164,848)	(179,443)	13,611,053
DEDUCTIONS FROM PLANT:				
Reserve for Deferred Income Taxes	155,092,521	22,165,290	(1,865,219)	175,392,592
Customer Deposits	1,063,454	70,891	0	1,134,345
Customer Advances	5,934,407	(67,024)	0	5,867,383
Total Deductions from Plant	162,090,382	22,169,157	(1,865,219)	182,394,320
RATE BASE	508,876,751	(28,817,469)	(4,743,127)	475,316,155
COST OF CAPITAL	8.00%	7.99%	0.00%	7.72%
RETURN ON RATE BASE	**40,710,140**	**(2,353,403)**	**(1,662,330)**	**36,694,407**

Note: Numbers may not add due to rounding.

E. Schedule 5 - Cost of Capital

	PER COMPANY			
	PRINCIPAL	PERCENTAGE	COST	RATE OF RETURN
Long-Term Debt	$210,000,000	47.06%	5.47%	2.57%
Preferred Stock	$0	0.00%	0.00%	0.00%
Common Equity	$282,681,920	52.94%	10.25%	5.43%
Total Capital	$492,681,920	100.00%		8.00%
Weighted Cost of				
Debt				2.57%
Equity				5.43%
Cost of Capital				8.00%

	COMPANY ADJUSTMENTS			
Long-Term Debt	$310,000,000	47.20%	5.47%	2.58%
Preferred Stock	$0	0.00%	0.00%	0.00%
Common Equity	$346,733,040	52.80%	10.25%	5.41%
Total Capital	$656,733,040	100.00%		7.99%
Weighted Cost of				
Debt				2.58%
Equity				5.41%
Cost of Capital				7.99%

	PER ORDER			
	PRINCIPAL	PERCENTAGE	COST	RATE OF RETURN
Long-Term Debt	$310,000,000	47.90%	5.44%	2.61%
Preferred Stock	$0	0.00%	0.00%	0.00%
Common Equity	$337,190,540	52.10%	9.80%	5.11%
Total Capital	$647,190,540	100.00%		7.70%
Weighted Cost of				
Debt				2.61%
Equity				5.11%
Cost of Capital				7.72%

F. Schedule 6 - Cash Working Capital

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Non-Gas O&M Expenses (Net Uncollectible)	69,028,510	(1,791,893)	(1,035,414)	66,201,203
Taxes Other Than Income	19,427,378	(73,042)	(1,026,175)	18,328,161
Total Costs Applicable to Cash Working Capital	88,455,888	(1,864,935)	(2,061,589)	84,529,364
Cash Working Capital Factor for Other O&M Expense	8.70%	8.70%	8.70%	8.70%
Total Cash Working Capital Allowance*	**7,699,297**	**(162,326)**	**(179,443)**	**7,357,528**

Composite Total times (31.77/365) or 8.70%

Note: Numbers may not add due to rounding.

G. Schedule 7 - Taxes Other Than Income Taxes

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
FICA Taxes	2,054,274	(34,780)	0	2,019,494
Medicare Taxes	573,026	(9,702)	0	563,324
Federal Unemployment Taxes	15,606	(56)	0	15,550
Mass Unemployment Taxes	138,876	(486)	0	138,390
State Insurance Premium	31,200	0	0	31,200
Property Taxes	16,373,426	(28,018)	(1,026,175)	15,319,233
Corporate Excise Tax	221,028	0	0	221,028
State Sales and Use Tax	19,942	0	0	19,942
Total Taxes Other Than Income Taxes	**19,427,378**	**(73,042)**	**(1,026,175)**	**18,328,161**

Note: Numbers may not add due to rounding.

H. Schedule 8 - Income Taxes

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Rate Base	508,876,751	(28,817,469)	(4,743,127)	475,316,155
Return on Rate Base	40,710,140	(2,353,403)	(1,662,330)	36,694,407
Add: Non-Deductible Depreciation	57,445	0	(123,796)	(66,351)
Less: Interest Expense	(13,078,133)	692,603	0	(12,385,530)
Less: Amortization of Invest. Tax Credit	(150,021)	0	0	(150,021)
Taxable Income Base	27,539,431	(1,660,800)	(1,786,126)	24,092,506
Gross Up Factor	1.6722	1.6722	1.6722	1.6722
Taxable Income	46,052,566	(2,777,258)	(2,986,832)	40,288,476
Mass Franchise Tax at 8%	3,684,205	(222,181)	(238,947)	3,223,078
Federal Taxable Income	42,368,361	(2,555,077)	(2,747,886)	37,065,398
Federal Income Tax at 35%	14,828,926	(894,277)	(961,760)	12,972,889
Total Income Taxes	18,513,131	(1,116,458)	(1,200,707)	16,195,967
Less: Amortization of Investment Tax Credit	(150,021)	0	0	(150,021)
Total Income Taxes	**18,363,110**	**(1,116,458)**	**(1,200,707)**	**16,045,946**

Note: Numbers may not add due to rounding.

I. Schedule 9 - Revenues

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Firm Distribution Revenue:				
Billed Sales - Distribution	146,213,372	3,958,963	0	150,172,335
Billed Sales - Special Contract	2,732,655	20,419	0	2,753,074
Total Firm Distribution Revenue	148,946,027	3,979,382	0	152,925,409
Other Operating Revenue Adjustments:				
Late Payment Charges (487)	148,322	0	0	148,322
Returned Check Fee (488)	26,876	0	0	26,876
Reactivation Fee (488)	210,974	0	0	210,974
Property Rent (493)	657,230	(6,798)	0	650,432
Services to NSTAR Gas (454)	126,216	0	0	126,216
Phone Referral (456)	39,523	0	0	39,523
Other Gas Revenue (495)	262,926	0	0	262,926
Total Other Operating Revenue Adjustments	1,472,066	(6,798)	0	1,465,268
Total Operating Revenue	**150,418,093**	**3,972,584**	**0**	**154,390,677**

Note: Numbers may not add due to rounding.

J. Schedule 10

For illustrative purposes only

Rate Class	ADJUSTED TEST YEAR BASE REVENUES	ADJUSTED TOTAL TEST YEAR REVENUES	PER ORDER CGA & LDAC INCREASE (absent baseline HOPCo)	PER ORDER BASE REVENUE AT EROR	REVENUES CREDITED TO BASE RATES	PER ORDER REVENUE INCREASE AT EROR	10% REVENUE INCREASE CAP	PER ORDER REVENUE TO BE REALLOCATED 10% CAP	BASE RATE REVENUE ALLOCATOR	PER ORDER REVENUE REALLOCATION PER 10% CAP
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
Residential (R-1 and R-2)	$ 3,690,127	$ 6,737,657	$ 73,865	$ 6,882,767	$ 77,759	$ 3,188,747	$ 673,766	$ 2,514,981	$ -	$ -
Residential (R-3 and R-4)	$ 94,376,267	$ 263,130,461	$ 4,068,688	$ 106,696,861	$ 2,167,729	$ 14,221,552	$ 26,313,046	$ -	$ 106,696,861	$ 1,642,842
Rate G-41	$ 14,070,266	$ 47,206,049	$ 668,260	$ 16,039,578	$ 399,920	$ 2,237,651	$ 4,720,605	$ -	$ 16,039,578	$ 246,966
Rate G-42	$ 14,890,728	$ 66,135,753	$ 1,033,969	$ 13,624,968	$ 517,659	$ (749,450)	$ 6,613,575	$ -	$ 13,624,968	$ 209,788
Rate G-43	$ 5,969,579	$ 29,395,389	$ 472,889	$ 5,367,161	$ 221,462	$ (350,992)	$ 2,939,539	$ -	$ 5,367,161	$ 82,640
Rate G-51	$ 3,311,239	$ 12,704,279	$ 190,005	$ 3,576,369	$ 93,822	$ 361,313	$ 1,270,428	$ -	$ 3,576,369	$ 55,066
Rate G-52	$ 5,045,239	$ 28,762,884	$ 479,849	$ 5,427,536	$ 207,085	$ 655,061	$ 2,876,288	$ -	$ 5,427,536	$ 83,569
Rate G-53/T-1	$ 8,818,889	$ 72,352,586	$ 1,373,544	$ 12,606,759	$ 532,905	$ 4,628,509	$ 7,235,259	$ -	$ 12,606,759	$ 194,110
Total Company	$ 150,172,335	$ 526,425,057	$ 8,361,069	$ 170,221,999	$ 4,218,341	$ 24,192,392	$ 52,642,506	$ 2,514,981	$ 163,339,232	$ 2,514,981

Rate Class	PER ORDER REVENUE INCREASE AFTER REVENUE REALLOCATION PER 10% CAP	PER ORDER BASE REVENUES OVER 126% CAP	BASE RATE REVENUE ALLOCATOR	PER ORDER REVENUE REALLOCATION PER 126% CAP	PER ORDER BASE REVENUE INCREASE AFTER 1ST ITERATION	PER ORDER BASE REVENUES OVER 126% CAP 2ND ITERATION	BASE RATE REVENUE ALLOCATOR	PER ORDER REVENUE REALLOCATION AFTER 2ND ITERATION	PER ORDER BASE REVENUE INCREASE	PER ORDER BASE REVENUE REQUIREMENT	PER ORDER BASE DISTRIBUTION PERCENT INCREASE
	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)	(S)	(T)	(U)
Residential (R-1 and R-2)	$ 673,766	$ 109,739	$ -	$ -	$ 490,161	$ -	$ -	$ -	$ 490,161	$ 4,180,288	13.28%
Residential (R-3 and R-4)	$ 15,864,395	$ -	$ 106,696,861	$ 1,689,933	$ 13,485,639	$ 949,592	$ -	$ -	$ 12,536,047	$ 106,912,315	13.28%
Rate G-41	$ 2,484,617	$ -	$ 16,039,578	$ 254,045	$ 2,070,403	$ 201,442	$ -	$ -	$ 1,868,961	$ 15,939,227	13.28%
Rate G-42	$ (539,662)	$ -	$ 13,624,968	$ 215,801	$ (1,357,831)	$ -	$ 13,624,968	$ 560,179	$ (797,651)	$ 14,093,077	-5.36%
Rate G-43	$ (268,352)	$ -	$ 5,367,161	$ 85,008	$ (656,232)	$ -	$ 5,367,161	$ 220,666	$ (435,566)	$ 5,534,014	-7.30%
Rate G-51	$ 416,379	$ -	$ 3,576,369	$ 56,645	$ 283,019	$ -	$ 3,576,369	$ 147,039	$ 430,058	$ 3,741,297	12.99%
Rate G-52	$ 738,631	$ -	$ 5,427,536	$ 85,965	$ 344,747	$ -	$ 5,427,536	$ 223,149	$ 567,895	$ 5,613,134	11.26%
Rate G-53/T-1	$ 4,822,619	$ 2,277,657	$ -	$ -	$ 1,171,418	$ -	$ -	$ -	$ 1,171,418	$ 9,990,307	13.28%
Total Company	$ 24,192,392	$ 2,387,396	$ 150,732,473	$ 2,387,396	$ 15,831,323	$ 1,151,034	$ 27,996,034	$ 1,151,034	$ 15,831,323	$ 166,003,658	10.54%

NOTE: Rates are designed exclusive of the $2.72 million low income subsidy.

KEY

(A) RR-DPU-18(C) (baseline for HOPCo not removed)
(B) Test year revenues for base + LDAC+HOPCo+CGA (see RR DPU 18C)
(C) CGA and LDAC increase minus HOPCo baseline (see Exhibit NSTAR-MFF-4 (8/21/2015 Update))
(D) Schedule 1 Total cost of service allocated based on proposed seasonal base revenues at EROR
(E) Special Contract Revenue and Fees (RR DPU-18(d))
(F) Col. (D) - Col. (A) - Col. (E) + Col. (C)
(G) 10% x Col. (B)
(H) If Col. (G) is less than Col. (F), then Col. (F) minus Col. (G), otherwise zero
(I) If Col. (H) is greater than zero then zero, othewise, Col. (D)
(J) If Col. (I) equals zero, then zero, otherwise, (Col. (I)/Col. (I Total)) * (Col. (H Total))
(K) If Col. (H) equals zero, then Col. (F) plus Col. (J), otherwise, Col. (G)
(L) If ((Col. (K) - Col. (C))/Col. (A) is greater than the base rate cap increase then (Col. (K) - Col. (C) - (Col. (A) * base rate cap increase)), otherwise, zero
(M) If Col. (L) is greater than zero, then zero, othewise, Col. (I)
(N) (Col. (L Total)) * (Col. (M)/Col. (M Total))
(O) Col. (K) - Col. (C) - Col. (L) + Col. (N)
(P) If ((Col. (O)/Col. (A)) is greater than the base revenue cap increase, then (Col. (O) - (Col. (A) * base revenue cap increase)), otherwise zero
(Q) If ((Col. (P)+ Col. (L)) is greater than zerp, then zero, otherwise Col. (M)
(R) Col. (P Total) * (Col. (Q)/(Col (Q Total))
(S) Col. (O) - Col. (P) + Col. (R)
(T) Col. (S) + Col. (A)
(U) Col. (S)/Col. (A)

XVI. ORDER

Accordingly, after due notice, hearing and consideration, it is

ORDERED: That tariffs M.D.P.U. Nos. 400B, 401C, 402G, 403B, 404A, 406B, 407D, 409, 420A, 421D, 422A, 423D, 430A, 431A, 432A, 433A, 434A, 435A, 437A, 450A, 451A, and 452A , filed by NSTAR Gas Company on December 17, 2014, to become effective on November 1, 2015, are DISALLOWED; and it is

FURTHER ORDERED: That NSTAR Gas Company shall file new schedules of rates and charges designed to increase annual gas base distribution revenues by $15,831,322; and it is

FURTHER ORDERED: That NSTAR 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 NSTAR Gas Company shall comply with all other orders and directives contained in this Order; and it is

FURTHER ORDERED: That the new rates shall apply to all gas consumed on or after January 1, 2016, but unless otherwise ordered by the Department, shall not become effective earlier than the seven days after the rates are filed with supporting data demonstrating that such rates comply with this Order.

By Order of the Department,

/s/

Angela M. O'Connor, Chairman

/s/

Jolette A. Westbrook, Commissioner

/s/

Robert E. Hayden, Commissioner

An 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 the 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. G.L. c. 25, § 5.