# The Commonwealth of Massachusetts

## DEPARTMENT OF PUBLIC UTILITIES

D.P.U. 19-120 October 30, 2020

Petition of NSTAR Gas Company doing business as Eversource Energy, pursuant to G.L. c. 164, § 94 and 220 CMR 5.00, for Approval of a General Increase in Base Distribution Rates for Gas Service and a Performance Based Ratemaking Mechanism.

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APPEARANCES: Cheryl M. Kimball, Esq.
Danielle C. Winter, Esq.
Kerri A. Mahoney, Esq.
Jameson Calitri, Esq.
Jessica Buno Ralston, Esq.
Keegan Werlin LLP
99 High Street, Ste 2900
Boston, Massachusetts 02110
FOR: NSTAR GAS COMPANY
Petitioner

Maura Healey, Attorney General
Commonwealth of Massachusetts
By: Joseph W. Rogers
John J. Geary
Matthew E. Saunders
Donald Boecke
Ashley Gagnon
Shannon Beale
Jo Ann Bodemer
Assistant Attorneys General
Office of Ratepayer Advocacy
One Ashburton Place
Boston, Massachusetts 02108
Intervenor

Department of Energy Resources
Commonwealth of Massachusetts
By: Rachael Graham Evans, Esq.
Robert H. Hoaglund II, Esq.
Ben Dobbs, Esq.
Colin P. Carroll, Esq.
100 Cambridge Street, Suite 1020
Boston, Massachusetts 02114
Intervenor

Charles Harak, Esq.
National Consumer Law Center
7 Winthrop Square, 4th Floor
Boston, Massachusetts 02110

-and-

Jerrold Oppenheim, Esq.
57 Middle Street
Gloucester, Massachusetts 01930
FOR: THE LOW-INCOME WEATHERIZATION AND FUEL ASSISTANCE PROGRAM NETWORK AND THE MASSACHUSETTS ENERGY DIRECTORS ASSOCIATION
Intervenor

Nicole Horberg Decter, Esq.
Jasper Groner, Esq.
Segal, Roitman, LLP
33 Harrison Avenue, 7th Floor
Boston, Massachusetts 02111
FOR: UNITED STEELWORKERS OF AMERICA, LOCAL 12004
Intervenor

John J. McNutt
General Attorney
U.S. Army Legal Services Agency
Regulatory Law Division
Office of the Judge Advocate General
9275 Gunston Road, Suite 1300
Fort Belvoir, Virginia 22060
FOR: THE UNITED STATES DEPARTMENT OF DEFENSE AND ALL OTHER FEDERAL EXECUTIVE AGENCIES
Intervenor

Joey Lee Miranda, Esq.
Robinson & Cole LLP
280 Trumbull Street
Hartford, Connecticut 06103
FOR: DIRECT ENERGY SERVICES, LLC; DIRECT ENERGY BUSINESS, LLC; AND DIRECT ENERGY BUSINESS MARKETING, LLC
Limited Intervenors

Courtney Feeley Karp, Esq.
Jonathan S. Klavens, Esq.
Klavens Law Group, P.C.
420 Boylston Street, Suite 610
Boston, Massachusetts 02116
FOR: HOME ENERGY EFFICIENCY TEAM, INC.
Limited Intervenor

James M. Avery, Esq.
Pierce Atwood LLP
100 Summer Street, Suite 2250
Boston, Massachusetts 02110
FOR: THE BERKSHIRE GAS COMPANY
Limited Participant

Laura S. Olton, Esq.
LSO Energy Advisors, LLC
38 Thackeray Road
Wellesley, Massachusetts 02481
FOR: POWEROPTIONS, INC.
Limited Participant

Robert Ruddock, Esq.
Locke Lord Public Policy Group
111 Huntington Avenue
Boston, Massachusetts 02199
FOR: THE ENERGY CONSORTIUM
Limited Participant

Paul A. Scoff, Esq.
Sprague Operating Resources, LLC
185 International Drive
Portsmouth, New Hampshire 03801
FOR: SPRAGUE OPERATING RESOURCES, LLC
Limited Participant

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# I. INTRODUCTION

On November 8, 2019, NSTAR Gas Company doing business as Eversource Energy ("NSTAR Gas" or "Company") filed a petition with the Department of Public Utilities ("Department") seeking approval of an increase to base distribution rates for gas service pursuant to G.L. c. 164, § 94, as well as other proposals. NSTAR Gas's last increase in base distribution rates went into effect on January 1, 2016. NSTAR Gas Company, D.P.U. 14-150, at 434 (2015).

NSTAR Gas operates as a wholly owned subsidiary of Yankee Energy System, Inc., a holding company that is a wholly owned subsidiary of Eversource Energy ("Eversource") (Exh. ES-WJA/DPH-1, at 17). The Company is engaged in the retail distribution and sale of natural gas to approximately 296,000 customers in 51 communities in central and eastern Massachusetts, covering 1,067 square miles (Exh. ES-WJA/DPH-1, at 17).

In the instant case, NSTAR Gas seeks to increase base distribution rates to generate $34,970,916 in additional revenues, an approximate 17-percent increase over current operating revenues (Exh. ES-DPH/ANB-2 (Rev. 3), Sch. 1, at 1).[1] The Company based its proposed base distribution rate increase on a test year of January 1, 2018, through December 31, 2018 (Exh. ES-WJA/DPH-1, at 9).

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[1] In its initial filing, NSTAR Gas sought to increase base distribution rates to generate $38,034,254, an approximate 19-percent increase over current operating revenues (Exh. ES-DPH/ANB-2, Sch. 1, at 1). The Company revised the proposed increase during the course of this proceeding.

The Company's requested rate increase includes the recovery of merger-related costs and exogenous costs associated with the settlements approved by the Department in BEC Energy/Commonwealth Energy System, D.T.E. 99-19 (1999) and NSTAR/Northeast Utilities Merger, D.P.U. 10-170 (2012) (Exh. ES-DPH/ANB-1, at 90-92, 105-106). Additionally, the Company proposes to implement a five-year performance-based ratemaking plan ("PBR Plan") that includes a mechanism ("PBRM") that would allow NSTAR Gas to adjust its distribution rates on an annual basis through the application of a revenue-cap formula and a set of metrics to evaluate the Company's performance (Exh. ES-WJA/DPH-1, at 8). Within the PBR Plan, the Company proposes to undertake two clean energy demonstration projects over the next five years: a gas demand response program and a geothermal network, with estimated costs of $2,305,729 and $12,810,645, respectively (Exhs. ES-WJA/DPH-1, at 8-9; ES-PMC/MRG-1, at 26, 41, 52).

Finally, NSTAR Gas proposes a number of tariff changes. The Company proposes changes to its distribution service terms and conditions tariff,[2] including updates to its current fees and a new sales tax abatement fee; a new PBR adjustment tariff to implement the PBRM; revisions to the local distribution adjustment clause ("LDAC"), default service, and

[2] Initially, the Company proposed several changes to its terms and conditions tariff in proposed tariff M.D.P.U. No. 400E that addressed the responsibilities and rights of gas suppliers (Exhs. ES-RDC/LMC-2, at 1-75; ES-RDC/LMC-3, at 1-89). On June 29, 2020, the Company moved to withdraw those revisions. D.P.U. 19-120, Motion to Withdraw Certain Proposed Tariff Revisions (June 29, 2020). On July 1, 2020, the Department approved the Company's motion to withdraw on the record (Tr. 12, at 1536-1537).

retail rate tariffs; and a customer connection rider tariff to implement a surcharge of 30 percent of a customer's base distribution charges for a period of 20 years on customer meters connected to the system on or after November 1, 2021 (Exh. ES-RDC/LMC-1; proposed M.D.P.U. Nos. 400E, 401G, 402S, 403D, 404C, 409D, 411, 420D, 421G, 422D, 423G, 430D through 435D, 450C, 451C, 452C, and 453).[3]

The Department docketed the instant petition as D.P.U. 19-120 and suspended the effective date of the proposed rate increase until October 1, 2020, to investigate the propriety of the Company's request. The Department further suspended the effective date of the Company's proposed tariffs until November 1, 2020, as a result of subsequent filings. D.P.U. 19-120, Suspension Order (April 22, 2020) (see Section II, below).

## II. PROCEDURAL HISTORY

On November 12, 2019, the Attorney General of the Commonwealth of Massachusetts ("Attorney General") filed a notice of intervention pursuant to G.L. c. 12, § 11E)[4]

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[3] In the intervening period, NSTAR Gas filed, and the Department approved, M.D.P.U. No. 402S in its gas system enhancement plan proceeding. NSTAR Gas Company, D.P.U. 19-GSEP-06, at 29 (April 30, 2020). For clarity, we cite to the proposed M.D.P.U. No. 402S as originally submitted in this docket. In its compliance filing, NSTAR Gas shall refile the LDAC tariff consistent with the directives in D.P.U. 19-GSEP-06 and the directives contained herein using the next available M.D.P.U. number.

[4] On January 3, 2020, the Department approved the Attorney General's retention of experts and consultants, filed pursuant to G.L. c. 12, § 11E(b), to assist her in representing consumer interests in this case at a cost not to exceed $550,000. D.P.U. 19-120, Order on Attorney General's Notice of Retention of Experts and Consultants (January 3, 2020). The costs incurred by the Attorney General in this proceeding are reimbursed to her by NSTAR Gas, and the Company recovers these costs from its ratepayers.

Additionally, the following entities were granted full party intervenor status: (1) the Massachusetts Department of Energy Resources ("DOER"); (2) the Department of Defense and all other Federal Executive Agencies ("DOD-FEA"); (3) United Steelworkers, Local 12004 ("United Steelworkers"); and (4) the Low-Income Weatherization and Fuel Assistance Program Network and the Massachusetts Energy Directors Association ("Low-Income Network"). The Department granted limited intervenor status to Direct Energy Services LLC, Direct Energy Business LLC, and Direct Energy Business Marketing LLC (together, "Direct Energy") and the Home Energy Efficiency Team, Inc. ("HEET"). The Department granted limited participant status to The Berkshire Gas Company; Power Options, Inc.; The Energy Consortium ("TEC"); and Sprague Operating Resources LLC.[5]

Pursuant to notice duly issued on November 26, 2019, the Department held four public hearings in NSTAR Gas's service area: (1) in Boston on February 24, 2020; (2) in Worcester on February 25, 2020; (3) in New Bedford on February 27, 2020; and (4) in Dedham on March 3, 2020.[6] The Department also received written comments from NSTAR Gas ratepayers and others.

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5 For the Hearing Officer's Rulings regarding intervention, limited intervention, and limited participant status, refer to D.P.U. 19-120, Stamp-Granted Petitions for Intervention (December 18, 2019); D.P.U. 19-120, Procedural Conference Transcript at 5-9 (January 7, 2020); D.P.U. 19-120, Hearing Officer Ruling on Petition for Intervention at 5 (January 28, 2020).

6 A fifth public hearing was scheduled on March 5, 2020, in Plymouth at Plymouth North High School. On March 5, 2020, the Plymouth Public Schools announced that all schools in Plymouth would be closed on March 6, 2020, due to possible COVID-19 contamination. Based on this announcement, the Department cancelled the public hearing in the interest of public health and safety.

On March 17, 2020, the Company moved to amend the procedural schedule to allow Eversource and the Attorney General to engage in settlement discussions regarding Eversource's acquisition of Bay State Gas Company doing business as Columbia Gas of Massachusetts ("Bay State").[7] United Steelworkers also filed a motion on March 18, 2020, seeking an extension of the deadline to issue discovery due to office closures and logistical challenges arising out of the COVID-19 pandemic. On April 2, 2020, the Department granted both motions and established an amended procedural schedule pursuant to 220 CMR 1.02(5) subject to the Company filing proposed tariffs effective May 1, 2020, to replace in their entirety the proposed tariffs submitted on November 9, 2019. D.P.U. 19-120, Hearing Officer Ruling on Motions to Amend the Procedural Schedule and Procedural Directive at 2, 4 (April 2, 2020). On April 16, 2020, the Company filed replacement tariffs, which the Department suspended until November 1, 2020. D.P.U. 19-120, Suspension Order (April 22, 2020).

In accordance with the amended procedural schedule, evidentiary hearings were scheduled to occur in the month of June 2020. Pursuant to Executive Order No. 591, Declaration of a State of Emergency to Respond to COVID-19, on June 6, 2020, Governor Baker issued COVID-19 Order No. 38. Effective June 8, 2020, gatherings that brought together more than ten persons into close physical proximity in any confined indoor or

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[7] On October 7, 2020, the Department approved this asset purchase and sale transaction. <u>Eversource Energy, NiSource Inc., Eversource Gas Company of Massachusetts, and Bay State Gas Company d/b/a Columbia Gas of Massachusetts</u>, D.P.U. 20-59/19-140/19-141 (October 7, 2020).

outdoor space remained prohibited throughout the Commonwealth. After due consideration of the ongoing assemblage prohibition, the statutory deadline for order issuance, and the interests of the parties to this proceeding, the Department found that it was necessary to facilitate the evidentiary hearings via videoconference. D.P.U. 19-120, Hearing Officer Memorandum and Ground Rules for Virtual Evidentiary Hearings (June 9, 2020).

The Department held twelve days of virtual evidentiary hearings from June 16, 2020, to July 1, 2020. In support of the Company's filing, NSTAR Gas sponsored the testimony of 18 witnesses: (1) William J. Akley, president, gas distribution business, Eversource; (2) Douglas P. Horton, vice president, distribution rates and regulatory requirements, Eversource Energy Service Company ("ESC"); (3) Penelope M. Conner, chief customer officer and senior vice president, ESC; (4) Michael Goldman, director, regulatory, evaluation and support, energy efficiency, ESC; (5) Julia Frayer, managing director, London Economics International LLC ("LEI"); (6) Dr. Marie N. Fagan, managing consultant and lead economist, LEI; (7) Ashley N. Botelho, manager of revenue requirements, ESC; (8) Robert B. Hevert, managing partner, ScottMadden, Inc.; (9) Sasha Lazor, director of compensation, ESC; (10) Michal P. Synan, director of benefits strategy and human resources shared services, ESC; (11) John J. Spanos, senior vice president, Gannett Fleming Valuation and Rate Consultants; (12) David A. Heintz, vice president, Concentric Energy Advisors; (13) Melissa F. Bartos, assistant vice president, Concentric Energy Advisors; (14) Richard D. Chin, manager of rates, ESC; (15) Lisa Cullen, manager of gas supply operations, ESC; (16) Leanne M. Landry, director of budget and investment planning, ESC;

(17) Thomas C. Desroisers, manager of budget and investment planning, ESC; and (18) Eric Soderman, manager of gas procurement and market analytics, ESC.[8]

The Attorney General sponsored the testimony of ten witnesses: (1) David J. Effron, consultant; (2) John Defever, consultant, Larkin & Associates, PLLC; (3) Dr. Mark N. Lowry, president, Pacific Economics Group Research LLC; (4) Scott Rubin, consultant; (5) Dr. J. Randall Woolridge, professor of finance at Pennsylvania State University; (6) David J. Garrett, managing member of Resolve Utility Consulting, PLLC; (7) Dwight Etheridge, vice president, Exeter Associates, Inc.; (8) Frank Radigan, principal in the Hudson River Energy Group; (9) Timothy Newhart, financial analyst, Office of Ratepayer Advocacy of the Massachusetts Office of the Attorney General; and (10) Jerome D. Mierzwa, principal and president of Exeter Associates, Inc. DOD-FEA sponsored the testimony of Michael P. Gorman, managing principal, and Christopher C. Walters, associate, Brubaker and Associates, Inc. Direct Energy sponsored the testimony of Keira Sanders, manager of retail natural gas operations and Marc Hanks, senior manager, corporate and regulatory affairs, Direct Energy.

On July 24, 2020, the Attorney General, DOER, DOD-FEA, Low-Income Network, HEET, and TEC submitted initial briefs. Direct Energy and PowerOptions, Inc. each submitted a letter in lieu of initial briefs. On August 10, 2020, the Company submitted its

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8 During evidentiary hearings, the Company made the following witnesses, who had not submitted written testimony, available for cross examination: Kelly Dimeo, director of information technology project management and enterprise architecture, ESC; and Sean Noonan, director of information technology business solutions, ESC.

initial brief.[9] On August 25, 2020, the Attorney General, DOER, DOD-FEA, HEET, and TEC submitted reply briefs. On August 31, 2020, NSTAR Gas submitted its reply brief, and on September 1, 2020, NSTAR Gas filed its final revenue requirement schedules and updates to certain discovery requests. The evidentiary record consists of approximately 1800 exhibits and 62 responses to record requests.

## III. ATTORNEY GENERAL'S MOTION TO STRIKE

### A. Introduction

At the conclusion of evidentiary hearings, NSTAR Gas was directed to file its reply brief and final revenue requirement schedules by August 28, 2020 (Tr. 12, at 1611). In addition, the Hearing Officer stated that he would be "keeping the record open for the limited purposes of receiving responses to record requests and updates to certain information requests, for example related to rate-case expense" (Tr. 12, at 1611). On August 28, 2020, NSTAR Gas filed a motion for a one-business day extension to file its final revenue requirement schedules, which the Department granted. D.P.U. 19-120, Hearing Officer Stamp-Granted Motion for an Extension of Time (August 31, 2020).

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9 On August 5, 2020, NSTAR Gas filed a motion for a one-business day extension to file its initial brief, which the Department granted. D.P.U. 19-120, Hearing Officer Stamp-Granted Motion for an Extension of Time (August 6, 2020). As a result, the Friday, August 7, 2020 deadline was extended to Monday, August 10, 2020. All subsequent reply brief deadlines were also extended such that intervenor reply briefs were due Tuesday, August 25, 2020, instead of Friday, August 21, 2020, and the Company's reply brief was due Monday, August 31, 2020 instead of Friday, August 28, 2020. D.P.U. 19-120, Stamp-Granted Motion for an Extension of Time at 2 (August 6, 2020).

On September 1, 2020, NSTAR Gas submitted a supplemental response to the Department's eighth record request ("RR-DPU-8 (Supp.)") and other exhibits.[10] The supplemental response contained information regarding the status of Eversource's new area work center located in Auburn, Massachusetts ("Auburn AWC") and an attached copy of a lease agreement between ESC and Rocky River Realty Company ("Rocky River").[11]

On September 10, 2020, the Attorney General filed a motion to strike pursuant to 220 CMR 1.04(5), 1.11(8) ("Motion to Strike"). The Attorney General specifically seeks to strike RR-DPU-8 (Supp.), including the attachment, and the corresponding citations to that response in the Company's reply brief (Motion to Strike at 1, 5, citing Company Reply Brief at 56-57; RR-DPU-8 (Supp.) & Att.). On September 17, 2020, NSTAR Gas filed an opposition to the Motion to Strike ("Company Response").

B. Positions of the Parties

1. Attorney General

The Attorney General contends that the Hearing Officer did not leave the record open for the Company to submit RR-DPU-8 (Supp.) (Motion to Strike at 4-5, citing Tr. 2, at 348-349; Tr. 12, at 1611-1612). The Attorney General maintains that 220 CMR 1.11(8) prohibits any party from presenting additional evidence after the hearing has been closed

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10 NSTAR Gas's filing also included the third revisions to Exhibits ES-DPH/ANB-2 and ES-DPH/ANB-3, the fourth supplemental response to Exhibit DPU-ES 10-15, and the second supplemental response to Exhibit DPU-ES 4-44.

11 Rocky River is a real estate holding company and wholly-owned subsidiary of Eversource (Exh. AG 1-98, Att.; Tr. 8, at 1050-1051).

unless the party files a motion and demonstrates good cause (Motion to Strike at 3-4). The Attorney General argues that the Department should strike RR-DPU-8 (Supp.) and the corresponding citations in the Company's reply brief because NSTAR Gas neither moved to reopen the record nor demonstrated good cause (Motion to Strike at 3).

The Attorney General asserts that allowing the response into the record would prejudice the intervenors because they had no opportunity to cross-examine Company witnesses regarding the new information (Motion to Strike at 5). The Attorney General avers that neither the Department nor the intervenors had an opportunity to ascertain the veracity of the Company's self-serving claims (Motion to Strike at 5).

Further, the Attorney General contends that the response is ineligible for consideration by the Department because it is not supported by an affidavit (Motion to Strike at 5, citing 220 CMR 1.01(1)). The Attorney General maintains that the Department must strike RR-DPU-8 (Supp.) and all citations thereof in the Company's reply brief from the evidentiary record in this proceeding based on the Company's failure to file a motion to reopen the record showing good cause coupled with its failure to submit an affidavit (Motion to Strike at 5). Finally, the Attorney General insists that if the Department allows RR-DPU-8 (Supp.) into the record it must strike the paragraph therein regarding the construction status and occupancy date, because the information is unresponsive to the record request, which asked for copies of all lease agreements related to the Auburn AWC (Motion to Strike at 6).

2. Company

The Company asserts that it properly filed RR-DPU-8 (Supp.) and that the Department should reject the Motion to Strike (Company Response at 2). The Company contends that the Hearing Officer expressly left the record open for the Company to submit pertinent information about the Auburn AWC, including a copy of a lease agreement and an update on the relocation of employees to the facility (Company Response at 3-6, citing Tr. 2, at 346-348, 350-351; Tr. 8, at 1041, 1049-1050; Tr. 12, at 1611). NSTAR Gas maintains that RR-DPU-8 (Supp.) was an update required by the Department and not extra-record evidence (Company Response at 3, 6). The Company also argues that it was not required to file an affidavit in support of RR-DPU-8 (Supp.) because record requests are written substitutes to oral testimony and are automatically part of the evidentiary record (Company Response at 7-8, citing D.P.U. 19-120, Procedural Notice and Ground Rules at 13 (January 28, 2020); Tr. 12, at 1609).

C. Analysis and Findings

It is axiomatic that a party's post-hearing brief may not serve the purpose of presenting facts or other evidence that are not in the record. Aquarion Water Company of Massachusetts, Inc., D.P.U. 17-90, at 15; New England Gas Company, D.P.U. 10-114, at 7-8 (2011); New England Gas Company, D.P.U. 08-35, at 15 (2009). Argument and comment filed on brief are not evidence in a case, as there is no opportunity for cross-examination or rebuttal testimony and evidence. D.P.U. 17-90 at 15-16; D.P.U. 10-114, at 8. A party's presentation of extra-record evidence to the fact-finder after the record has closed is an unacceptable tactic that is potentially prejudicial to the rights of other parties even when the evidence is excluded. D.P.U. 17-90 at 16; D.P.U. 10-114, at 8; Boston Gas Company, D.P.U. 88-67 (Phase II) at 7 (1989). Nonetheless, the Department routinely permits the record to remain open after the end of hearings for receipt of updated information on certain non-controversial cost of service items such as rate case expense and property tax. D.P.U. 17-90 at 16, citing D.P.U. 10-114, at 8; Fitchburg Gas and Electric Light Company, D.T.E. 02-24/25, at 11 (2002). The filing of updated information may also be permissible in extraordinary or compelling circumstances. D.P.U. 10-114, at 8, citing Bay State Gas Company, D.P.U. 89-81, at 45 (1989).

The Attorney General contends that RR-DPU-8 (Supp.) is not admissible because it constitutes unsworn testimony unsupported by an affidavit (Motion to Strike at 5). We disagree and will not grant the Attorney General's Motion to Strike on that basis. Record requests are written substitutes to oral answers given at evidentiary hearings under oath and as such they are automatically part of the evidentiary record unless a motion to strike is made and granted. D.P.U. 19-120, Procedural Notice and Ground Rules, § III.G (January 28, 2020);[12] D.P.U. 88-67, at 4. Accordingly, RR-DPU-8 (Supp.) does not constitute unsworn testimony.

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12 Pursuant to 220 CMR 1.06(5)(c)2:

> [T]he presiding officer shall establish discovery procedures in each case that take into account the legitimate rights of the parties in the context of the case at issue. In establishing discovery procedures, the presiding officer must exercise his or her discretion to balance the interests of the parties and ensure that the information necessary to complete the record is produced without unproductive delays.

NSTAR Gas did not file a motion to reopen the record upon a showing of good cause. Therefore, our decision on the Motion to Strike turns on whether, as the Company asserts, the Hearing Officer held the record open to accept RR-DPU-8 (Supp.) or, as the Attorney General asserts, the record was not held open for that purpose.

On June 17, 2020, just after the Hearing Officer issued the Department's record request for copies of all lease agreements related to the Auburn AWC, the Company's witness stated that NSTAR Gas intended to move its employees into the Auburn AWC by August 31, 2020, and committed to providing verification that the move had occurred (Tr. 2, at 350-351). In response to the Company's offer to provide said verification, the Hearing Officer responded, "Okay, thank you" (Tr. 2, at 351). On June 25, 2020, the Hearing Officer conducted further cross-examination of the witness regarding the anticipated in-service date of the Auburn AWC and the initial response to the Department's eighth record request, which provided that ESC had not executed a lease for the Auburn AWC at that time but anticipated that a lease would be executed by August 31, 2020 (RR-DPU-8). The witness testified that the Auburn AWC would be in-service when its employees were moved into the facility and that the Company's plan to complete the move in June 2020 had been delayed due to the COVID-19 pandemic (Tr. 8, at 1039-1043). In response to further examination about ESC's anticipated lease for the facility, the witness stated: "I think last week we did commit to providing verification that the move occurred on August 31, 2020, to the Department following the close of the hearings on this proceeding. I do think it would be reasonable if we also provided the lease agreement as well" (Tr. 8, at 1049-1050). Based on the examination by the Department's staff and the Company's responses, it was the clear intent of the Hearing Officer and understanding of the Company that the record was to be held open for the Company to submit verification that the NSTAR Gas employees had moved to the Auburn AWC and a copy of the lease for the facility, which the Company provided in RR-DPU-8 (Supp.) (Tr. 2, at 348-351; Tr. 8, at 1049-1050; Tr. 12, at 1611).

We acknowledge that the in-service date of the Auburn AWC was a contested issue in this proceeding, and because of that the information provided in RR-DPU-8 (Supp.) is not akin to the non-controversial updates such as property tax bills and rate case expense invoices typically provided after the conclusion of evidentiary hearings. Nevertheless, the Company testified at hearing that the move-in date and coinciding in-service date for the Auburn AWC had been delayed due to the COVID-19 pandemic (Tr. 8, at 1039-1043). The ongoing pandemic and state of emergency's unprecedented effects on the availability and predictability of acquiring goods and services in the Commonwealth constitute extraordinary circumstances. Therefore, the Hearing Officer did not abuse his discretion in holding the record open to receive the information contained in RR-DPU-8 (Supp.). D.P.U. 10-114, at 8; D.P.U. 89-81, at 45.

Lastly, the Attorney General asserts that if the Department does not strike RR-DPU-8 (Supp.) from the record in its entirety, then the Department should strike the paragraph in RR-DPU-8 (Supp.) regarding the Auburn AWC construction status and expected occupancy date because it is not responsive to the request. We disagree. The original response to RR-DPU-8 provided that the lease would be executed by August 31, 2020, i.e., the occupancy date (RR-DPU-8). The information contained in the paragraph of RR-DPU-8 (Supp.) is relevant to the original response, to the verification that the move has occurred, and to the information sought by the Hearing Officer during cross-examination. The Attorney General's claim that the paragraph is not responsive and should be stricken is without merit.

Based on the forgoing discussion, we conclude that (1) the Hearing Officer held the record open until September 1, 2020, for the purpose of receiving the information contained in RR-DPU-8 (Supp.); (2) the Company was not required to file a motion to reopen the record for good cause shown; (3) the Hearing Officer did not abuse his discretion; (4) the Company was not required to submit an affidavit; and (5) the paragraph in RR-DPU-8 (Supp.) regarding the Auburn AWC construction status and expected occupancy date contains information relevant to the Department's record request. Accordingly, the Attorney General's Motion to Strike is denied.

## IV. STIPULATED ADJUSTMENTS

### A. Introduction

On June 3, 2020, NSTAR Gas and the Attorney General submitted a joint motion pursuant to 220 CMR 1.02(5) requesting that the Department approve their stipulations regarding certain contested issues ("ES-AG Stipulations").[13] The Company and the Attorney

[13] Generally, a stipulation is a statement of facts agreed to by parties. This stipulation also includes issue of law (e.g., allowable costs and revenues, just and reasonable result, consistent with the public interest). The courts review stipulations of fact and stipulations of law differently. Goddard v. Goucher, 89 Mass. App. Ct. 41, 43 (2016). Importantly, a "court cannot be controlled by agreement of counsel on a subsidiary question of law." Goddard, 89 Mass. App. Ct. 41, 43 quoting Swift and

General proposed the stipulated adjustments to narrow the scope of evidentiary hearings and briefing (ES-AG Stipulations at 1). No other parties submitted a response to the motion.

NSTAR Gas and the Attorney General proposed adjustments to the following operations and maintenance ("O&M") expenses, which were incorporated into the Company's final revenue requirement schedules submitted on September 1, 2020: (1) decrease 401(k) expense by $212,480; (2) decrease employee awards expense by $10,956; (3) decrease severance expense by $59,537; and (4) decrease the inflation adjustment by $134,037 (ES-AG Stipulations at 2-3). In addition, the moving parties proposed to increase unbilled revenues by $295,098 and reduce rate base by $100,000 for customer advances (ES-AG Stipulations at 2-3). NSTAR Gas also agreed to credit customers for the remaining gains on sales of property and gains on the sale of the home heating protection business balance of $217,708 amortized over five years (ES-AG Stipulations at 3).[14] Lastly, the Company agreed to reduce its proposed depreciation accrual for Accounts 336, 367, and 369, in accordance with the modified accrual rates shown in Table 1 to the ES-AG Stipulations, and decrease depreciation expense by $1,459,659 (ES-AG Stipulations at 3).

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Company v. Hocking Valley Railway Company, 243 U.S. 282,289 (1917). See also Texas Instruments Federal Credit Union v. DelBonis, 72 F.3d 921, 928 (1st Cir 1995) ("Parties may not stipulate to the legal conclusions to be reached by the court"), quoting Saviano v. Commissioner of Internal Revenue, 765 F.2d 643, 645 (7th Cir. 1985).

14 NSTAR Gas will include the $43,542 credit ($217,708/5) in the Company's Local Distribution Adjustment Factor ("LDAF") (ES-AG Stipulations at 3).

Further, NSTAR Gas agreed to the following rate structure stipulations. The Company will adhere to a distribution rate increase cap of 175 percent of the system-average percentage increase, use the residential average cost to allocate service pipe costs for the residential classes, use the actual embedded cost of each type of meter to allocate meter and meter installation costs, and allocate house regulator costs only to customers who are not located on the low-pressure system (ES-AG Stipulations at 3).

On July 24, 2020, NSTAR Gas and the Low-Income Network submitted a joint motion pursuant to 220 CMR 1.02(5) requesting that the Department approve their stipulated adjustment to the low-income discount ("ES-LI Stipulation").[15] No other parties submitted a response to the motion.

B. Standard of Review

In assessing the reasonableness of an offer of settlement,[16] the Department reviews all available information to ensure that the settlement is consistent with Department precedent and the public interest. Fall River Gas Company, D.P.U. 96-60 (1996); Essex County Gas Company, D.P.U. 96-70 (1996); Boston Edison Company, D.P.U. 92-130-D at 5 (1996); Bay State Gas Company, D.P.U. 95-104, at 14-15 (1995); Boston Edison Company, D.P.U. 88-28/88-48/89-100, at 9 (1989). A settlement among the parties does not relieve the Department of its statutory obligation to conclude its investigation with a finding that a

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[15] This stipulation also involves an issue of law – rate design.

[16] The stipulations are in the nature of offers of settlement.

just and reasonable outcome will result. D.P.U. 95-104, at 15; D.P.U. 88-28/88-48/89-100, at 9.

It is well established that the Department's goals for utility rate structure are efficiency, simplicity, continuity, fairness, and earnings stability. D.P.U. 95-104, at 15; Bay State Gas Company, D.P.U. 92-111, at 283 (1992); see also Massachusetts Electric Company, D.P.U. 95-40, at 144-145 (1995). The Department has previously accepted settlements which include cost allocation and/or rate design when such settlements were consistent with the Department's goals. D.P.U. 96-60; D.P.U. 96-70; D.P.U. 95-104, at 15; Massachusetts Electric Company, D.P.U. 91-52 (1991).

C. Analysis and Findings

The Department has reviewed the stipulated adjustments to the O&M expenses listed above, unbilled revenues, rate base, and depreciation in light of the evidence, including the Company's initial filing and responses to information requests and the Attorney General's testimony and responses to information requests submitted in this proceeding.[17] Together, these stipulated adjustments provide for significant ratepayer savings and are consistent with findings that might reasonably have been made by the Department. Thus, the Department concludes that the proposed cost of service adjustments are consistent with both applicable

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17 The Department appreciates the efforts of the parties to potentially narrow contested issues, especially for this proceeding in which the Department first conducted extensive remote evidentiary hearings. See Boston Edison Company, Cambridge Electric Light Company, Commonwealth Electric Company, Fitchburg Gas and Electric Light Company, and Western Massachusetts Electric Company, D.P.U 94-162, at 18 (Department encourages settlement).

law and the public interest and approval of these adjustments results in a just and reasonable outcome of the specific issues raised therein. Accordingly, the Company and Attorney General's stipulated adjustments to NSTAR Gas's proposed cost of service are approved.

The Department has also reviewed the proposed adjustments to the Company's rate structure and the proposed adjustment to the Company's low-income discount. The Department has historically been reluctant to accept settlements that involve rate design issues. Massachusetts Electric Company, D.P.U. 84-240/85-146, at 3-4 (1985). Our reluctance to approve settlements that resolve rate structure issues, even if parties in the case can reach agreement, is based on the complicated nature of implementing the Department's rate structure goals. Cambridge Electric Light Company, D.P.U. 89-109, Interlocutory Order on Offer of Settlement at 3-4 (1989). The balancing of oft-competing goals involves the allocation of costs among classes and the design of rates within classes, in a way that moves rates toward costs consistent with continuity considerations. D.P.U. 89-109, Interlocutory Order on Offer of Settlement at 4. While parties representing limited constituencies in a rate case may come to some agreement on rate structure issues, this agreement might be to the detriment of other customers or be at odds with the Department's policy goals and objectives. D.P.U. 89-109, Interlocutory Order on Offer of Settlement at 4. Based on the findings in Section XII, below, the Department is unable to accept the Company and Attorney General's proposed rate structure adjustments or the Company and Low-Income Network's proposed adjustment to the low-income discount.

Accordingly, we grant in part, and deny in part, the joint motion of NSTAR Gas and the Attorney General, and we deny the joint motion of NSTAR Gas and the Low-Income Network. The Department's partial approval of the proposed stipulations does not constitute a determination as to the merits of any allegations or contentions made in this proceeding. In addition, the Department's acceptance does not establish a precedent for future filings, whether ultimately settled or adjudicated.

## V. PERFORMANCE-BASED RATEMAKING PROPOSAL

### A. Introduction

NSTAR Gas's proposed PBR Plan has three components: (1) a PBRM to adjust rates annually and provide revenue support for operations and capital investment; (2) cost recovery for two demonstration projects, one to test the feasibility of natural gas demand-response initiatives, and one to assess the viability of geothermal distribution; and (3) a set of scorecard metrics to measure the success of PBR Plan implementation (Exh. ES-WJA/DPH-1, at 5-6). The Company stated that it foresees changes in the operating environment for local distribution companies ("LDCs"), including increased capital investment outside of the GSEP and increased safety requirements (Exh. ES-WJA/DPH-1, at 11-12). The Company believes that the proposed PBR Plan is a better fit than traditional cost-of-service ratemaking, providing the revenue support necessary to address changes in the operating environment without diverting resources from the operation of the system (Exh. ES-WJA/DPH-1, at 12-13).

B. PBRM Proposal

1. Introduction

NSTAR Gas's proposed PBRM uses a revenue cap formula to adjust base distribution rates annually through an adjustment to the Company's revenue decoupling mechanism (Exh. ES-WJA/DPH-1, at 79-80). The PBRM would adjust the base revenue requirement approved in this proceeding, which serves as the revenue target for the revenue decoupling mechanism, according to the following formula:

$PBRAF_T = (GDPPI_{T-1} - X) + (Z_{REV} / \text{Base Revenue}_{T-1})$, where

$PBRAF_T$ is the percentage change to be applied to the Prior Year PBR Revenue;

$GDPPI_{T-1}$ is a price inflation index;[18]

X is a productivity offset;

Z is an adjustment for exogenous costs (positive or negative);

Base Revenue is the base distribution revenue requirement.

(Exh. ES-RDC/LMC-2, Proposed M.D.P.U. No. 411, § 6.0).

Two additional elements in the Company's proposed PBRM are not shown in the above formula. First, the Company proposed an earnings sharing mechanism ("ESM") that would provide either a credit or an additional charge to customers if earnings are higher or

18 GDPPI (also GDP-PI) refers to the gross domestic product price index, which measures changes in the prices of goods and services produced in the United States, including those exported to other countries. https://www.bea.gov/data/prices-inflation/gdp-price-index.

lower than the return on equity ("ROE") approved in this proceeding by more than 100 basis points (proposed M.D.P.U. No. 411, §§ 4.0, 9.0). Second, the annual revenue requirement associated with the investments for the two proposed demonstration projects would be recovered through a Y Factor (proposed M.D.P.U. No. 411, § 10.0). Each element of the Company's proposed revenue cap formula and PBRM is described in detail below.

2. Formula Elements

a. PBR Term

NSTAR Gas proposed an initial term of five years for the PBR Plan, with a provisional five-year extension (Exh. ES-WJA/DPH-1, at 79, 93-95).[19] The initial five-year PBR term would commence on November 1, 2020 and expire on October 31, 2025 (Exh. WJA/DPH-1, at 94). Within the five-year term, there would be four annual PBRM adjustments taking effect November 1, 2021, November 1, 2022, November 1, 2023, and November 1, 2024 (Exh. WJA/DPH-1, at 94). In conjunction with the PBR term, the Company proposed a stay-out provision whereby the Company may not file a base distribution rate case during the PBR term (Exh. ES-WJA/DPH-1, at 94). Under the

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19 The five-year extension is conditioned on the Department's approval of the following: (1) the two-part exogenous cost mechanism as proposed; (2) the proposed symmetrical ESM with a 100 basis point deadband; (3) the proposed cost of capital (ROE and capital structure); (4) the proposal to incorporate capital additions completed in 2019 and 2020 into rate base; and (5) a provision that would allow the Company to incorporate capital additions completed through December 31, 2024 into rate base in Year 5 of the PBR Plan term (Exh. ES-WJA/DPH-1, at 94-95).

stay-out, the Company would be eligible to file rate schedules to put new base distribution rates into effect no earlier than November 1, 2025 (Exh. ES-WJA/DPH-1, at 94).[20]

b. Post Test Year Capital Additions

NSTAR Gas proposed to recover the revenue requirement associated with non-GSEP capital additions completed through December 31, 2019, in base distribution rates effective with this Order; and capital additions completed through December 31, 2020, in base distribution rates effective on November 1, 2021 in the first PBRM adjustment (Exhs. ES-WJA/DPH-1, at 95; ES-DPH/ANB-1, at 9-10, 20-21; DPU-ES 7-3; AG 10-1). In addition, the Company conditions its proposed five-year PBR term extension in part on allowing the revenue requirement associated with the capital additions completed through December 31, 2024, into base distribution rates in year five of the PBR Plan term (Exh. ES-WJA/DPH-1, at 94-95). NSTAR Gas would include a determination in its September 15, 2024 PBRM adjustment filing of whether it has opted to stay out with a roll-in of capital additions in lieu of filing a base distribution rate case or other proposal for effect November 1, 2025 (Exh. ES-WJA/DPH-1, at 99). If the Company indicates in the September 15, 2024 PBRM adjustment filing that it has opted to roll in capital additions (and extended the PBR Plan term), NSTAR Gas would present capital project documentation through December 31, 2024, to the Department on or before April 1, 2025 for review and for roll-in to rates effective November 1, 2025 (Exh. ES-WJA/DPH-1, at 99).

20 In addition, the Company makes the stay-out contingent upon the Department's approval of the Company's proposed PBRM adjustment formula (Exh. ES-WJA/DPH-1, at 97-98; Tr. 3, at 393-397).

c. X Factor

NSTAR Gas proposed a productivity offset ("X factor")[21] to be calculated as:

> $X = TFPT_{GDI\text{-}US} + IPT_{GDI\text{-}US}$, where
>
> $TFPT_{GDI\text{-}US}$ is the total productivity trend differential between the electric[22] distribution industry in the Northeast region and the overall United States economy,
>
> $IPT_{GDI\text{-}US}$ is the total input price trend differential between the electric distribution industry and the overall United States economy.

(Exh. ES-RDC/LMC-2 (Rev.), Proposed M.D.P.U. No. 411, § 6.0).

When a PBRM utilizes an inflation factor that is a measure of economy-wide inflation, the X factor consists of the differential in expected productivity growth between the LDC industry and the overall economy, and the differential in expected input price growth between the overall economy and the LDC industry (Exhs. ES-JF/MF-1, at 45; ES-JF/MF-2, at 46). To determine the proposed X factor, NSTAR Gas conducted a productivity study of nationwide LDCs' distribution TFP and input price growth over the period 2003 through 2017 (Exh. ES-JF/MF-2, at 11). The Company used two different samples for this productivity study: (1) a sample of 83 U.S. LDCs intended to represent the overall nationwide LDC industry; and (2) a sample of 29 LDCs intended to represent the LDC

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21 The X factor, also referred to as a productivity target by the parties, consists of a total factor productivity ("TFP") differential, as measured by the difference of industry productivity growth and economy wide productivity growth, and an input price differential (Exhs. ES-JF/MF-1, at 45; ES-JF/MF-2, at 46).

22 The Department notes that the Company's proposed tariffs erroneously reference the electric distribution industry. The Department directs the Company to correct such references as part of its compliance filing.

industry in the Northeast (Exh. ES-JF/MF-1, at 21). For the industry TFP study and calculation of the X factor, the Company used several official U.S. government sources.[23]

TFP is defined as the ratio of quantity of outputs produced to quantity of inputs used in production (Exh. ES-JF/MF-2, at 15). Inputs and outputs should be those that most accurately represent the physical process behind the distribution of gas (Exh. ES-JF/MF-2, at 25). For the input measure, NSTAR Gas used capital expenditures and non-capital expenditures (operations, maintenance, and administration ("OM&A")) (Exh. ES-JF/MF-2, at 25). The Company then constructed quantity and price indices of total input for each firm and each year (Exh. ES-JF/MF-2, at 27-37). NSTAR Gas used number of customers as the sole productivity study output measure (Exh. ES-JF/MF-2, at 25).

The Company utilized a capital cost specification method referred to as the one hoss shay method (Exh. ES-JF/MF-2, at 31). The basic assumption of this method is that an asset provides a constant level of services over the service life of the asset (Exh. ES-JF/MF-2, at 31). The one hoss shay method also requires an average service life of all assets in order to estimate the quantity of capital retirements (Exh. ES-JF/MF-2, at 31-33).[24]

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23 The Company used firm-level data for sample LDCs from Federal Energy Regulatory Commission ("FERC") Form 2 and the U.S. Energy Information Administration ("EIA") (Exh. ES-JF/MF-2, at 25).[23] The Company used economy-wide data from: (1) U.S. Bureau of Labor Statistics ("BLS") Employer Cost Index ("ECI"); (2) U.S. Bureau of Economic Analysis ("BEA") Price Index for Gross Domestic Product ("GDP-PI"); (3) BLS Multifactor Productivity; (4) Federal Reserve Bank of St. Louis, Corporate Bond Yields; and (5) U.S. Treasury, U.S. Treasury Bonds and Inflation-Protected Securities (Exh. ES-JF/MF-1, at 25, 37).

24 In contrast, in the Attorney General's proposed TFP studies, she deployed the geometric decay and Kahn methods for capital cost specification (Exh. AG-MNL-2,

The initial results of the Company's study indicated that, for the period 2003-2017, the average growth in productivity for the national LDC industry sample was equal to 0.09 percent, while the economy-wide productivity growth was equal to 0.60 percent, which generated a productivity differential of -0.51 percent for the study period (0.09 percent less 0.60 percent = -0.51 percent) (Exh. ES-JF/MF-2, at 47). For the same period, the average input price growth for the national LDC industry sample was equal to 2.79 percent, while the economy-wide input price growth was equal to 2.51 percent, which generated an input price differential of -0.28 percent (2.51 percent less 2.79 percent = -0.28 percent) (Exh. ES-JF/MF-2, at 47). The sum of the national productivity differential and the national input price differential in the Company's initial results generated a -0.79 percent X factor (-0.51 percent plus -0.28 percent) (Exh. ES-JF/MF-2, at 47). When the Company initially conducted the TFP study using its regional LDC industry sample, the average growth in productivity was -0.39 percent, which generated a productivity differential of -0.98 percent (Exh. ES-JF/MF-2, at 47). The regional sample also produced an industry input price growth average of 2.83 percent, which generated an input price differential of -0.32 percent (Exh. ES-JF/MF-2, at 47). The sum of the regional productivity differential and the regional input price differential in the Company's initial study generated a -1.30 percent X factor (Exh. ES-JF/MF-2, at 47). During the course of the proceeding, the Company

at 2). Regarding geometric decay, the flow of services from investments in a given year declines at a constant rate over time (Exh. AG-MNL-2, at 13). The Kahn method decomposes capital cost into a price and quantity index using a simplified version of cost of service accounting (Exh. AG-MNL-2, at 15, 39).

acknowledged that energy efficiency program costs for three Massachusetts LDCs were inadvertently included in the initial TFP study results[25] (RR-DPU-21, at 1). After removing the energy efficiency program costs and rerunning the study, the TFP increased by three basis points and 12 basis points in the national and regional samples, respectively (RR-DPU-21, at 1). Accordingly, the national and regional X factors resulting from the update are -0.76 percent and -1.18 percent, respectively (RR-DPU-21, at 2).

The Company proposed that the updated X factor of -1.18 percent be incorporated in the PBRM, which observes the productivity average of the regional sample (Company Brief at 26, citing RR-DPU-21, at 2). The Company stated that this X factor is most appropriate because there are factors that may impact productivity growth in the LDC sector that vary between the Northeast Region and the rest of the U.S., specifically economies of scale, technology, and output growth (Exh. ES-JF/MF-1, at 29-31).

d. Consumer Dividend

NSTAR Gas proposed not to include a consumer dividend component to its PBRM (Exh. WJA/DPH-1, at 84). In theory, a consumer dividend reflects an expectation that efficiency gains not captured in the rates approved at the beginning of the PBR Plan term, will be realized as a result of the PBR Plan over the course of the PBR Plan term

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25 The Company's consultant represented that it excluded energy efficiency program costs associated with all Massachusetts LDCs included in the study sample, but discovered that for Boston Gas Company, Colonial Gas Company, and Bay State, such costs were reported in Account 905, rather than Account 815 (RR-DPU-21, at 1). The Company reran the TFP and benchmarking studies removing Account 905 for the three identified companies (RR-DPU-21, at 1).

(Exh. ES-WJA/DPH-1, at 83). A consumer dividend is designed to share those efficiency gains with customers. The proposal to exclude a consumer dividend was the result of a cost benchmarking study that compared the Company's cost performance to its peers, finding that NSTAR Gas was relatively efficient compared to its peers (Exh. ES-WJA/DPH-1, at 84).

e. Exogenous Cost Factor (Z Factor)

The Company proposed to include an exogenous cost provision ("Z factor"), which it defines as positive or negative changes to its costs that are beyond NSTAR Gas's control and are not reflected in the GDP-PI (Exh. ES-WJA/DPH-1, at 85). The Company further defined the criteria for any costs that would be eligible for recovery through the Z factor as those that are due to changes in tax laws, accounting requirements, or regulatory, judicial, or legislative acts, each of which uniquely affect the natural gas distribution industry (Exh. ES-WJA/DPH-1, at 85). More specifically, the Company proposed a two-part exogenous cost mechanism: (1) includes events that meet the Department's established criteria for an exogenous event (described above); and (2) a more targeted definition specific to exogenous events arising due to pipeline safety requirements imposed after November 8, 2019, with demonstrated cost impacts after the date of the PBRM, November 1, 2020 (Exh. ES-WJA/DPH-1, at 85-86). The Company stated that it would be necessary to include the two-part definition of exogenous event in order to commit to the five-year stay out (Exhs. ES-WJA/DPH-1, at 85; DPU-ES 12-9).

In addition, the exogenous cost for either proposed part would be required to meet a significance threshold of $700,000, which was determined by multiplying the Company's total operating revenues for calendar year 2018 of $499,895,237 by 0.001253[26] and then rounding upwards (Exhs. ES-WJA/DPH-1, at 86-87; DPU-ES 12-2).[27] The Company proposed two slightly different treatments of the threshold for the two proposed parts of the definition of an exogenous cost: (1) the significance threshold for the first part, the traditional exogenous factor, would include O&M cost changes in a single year, and (2) the significance threshold for the second part, specific to pipeline safety requirements, would allow for both capital and O&M cost changes, applied separately to capital and O&M (Exh. WJA/DPH-1, at 87). Further, the significance threshold for each part would be subject to annual adjustments based on changes in GDP-PI (Exh. WJA/DPH-1, at 87).

f. Y Factor

Initially, the Company proposed to recover the costs associated with the implementation of two demonstration projects through the Y factor component of the PBRM by amortizing the costs of the projects over the five-year term as actual costs are incurred (Exh. ES-WJA/DPH-1, at 90). The two demonstration projects include a gas demand response project and a geothermal distribution demonstration project (Exh. ES-WJA/DPH-1, at 90). These projects are discussed in more detail in Section VI. During the proceedings,

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26 The Company states that the Department has previously approved a factor of 0.001253 for use in deriving the threshold for exogenous cost recovery (Exh. ES-WJA/DPH-1, n. 14, citing NSTAR Electric Company/Western Massachusetts Electric Company, D.P.U. 17-05, at 397 (2017)).

27 The Company further explained that when considering the threshold for the Company's second part of the definition, the impact of a change in capital costs would be determined as the revenue requirement impact of the cost change attributed to the exogenous event (Exh. DPU-ES 12-5).

NSTAR Gas proposed that the Y factor be collected as a component of the local distribution adjustment factor ("LDAF") to work in tandem with the PBRM, but not as an explicit component of the PBR formula (Exh. ES-RDC/LMC-2 (Rev.) at 126; Tr. 7, at 366-367).

g. Earnings Sharing Mechanism

As part of the PBRM, the Company proposed to adopt an ESM with a symmetrical deadband of 100 basis points (Exh. WJA/DPH-1, at 91). The proposed ESM would trigger a sharing of earnings or losses with customers on a 75 (customers)/25 (shareholders) basis when the actual distribution ROE exceeds 100 basis points above or below the ROE authorized by the Department (Exh. ES-WJA/DPH-1, at 91).[28] NSTAR Gas indicated that its proposed ESM is necessary for the Company to commit to the five-year stay out (Exhs. ES-WJA/DPH-1, at 94; DPU-ES 12-9). Calendar year 2021 would be the first year for which the Company would evaluate whether an ESM adjustment were appropriate, for effect November 1, 2022 (Exh. ES-WJA/DPH-1, at 93).

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28 The Company proposed that the distribution ROE be calculated using earnings available for common equity and the capital structure approved by the Department in this proceeding (Exh. ES-WJA/DPH-1, at 92; proposed M.D.P.U. No. 411, § 9.0). The Company proposed that the calculation of utility net income used in the calculation of ROE will exclude incentive payments such as energy efficiency incentives, service-quality penalties, and any settlements or decisions related to prior periods (Exh. WJA/DPH-1, at 92; proposed M.D.P.U. No. 411, § 9.0).

3. Positions of the Parties

a. Attorney General

i. Introduction

The Attorney General argues that the Department should reject the proposed PBRM or, in the alternative, adopt the PBRM with certain changes and terminate the Company's GSEP (Attorney General Brief at 117, 137; Attorney General Reply Brief at 40, 54). The Attorney General claims that: (1) the PBR term of five years is inconsistent with Department precedent and not long enough to achieve the efficiency promised to ratepayers and shareholders; (2) the PBRM will result in the double recovery of capital addition costs; and (3) the Company's proposed X factor, ESM, and lack of consumer dividend render the proposal flawed, resulting in unjust and unreasonable rates that are not cost-based (Attorney General Brief at 114-116, 118, 134, 137; Attorney General Reply Brief at 37-39, 45-50). The Attorney General also criticizes the Company's threats to abandon the PBR Plan if the Department does not authorize all components as proposed (Attorney General Reply Brief at 53, citing Company Brief at 47). While the Attorney General makes specific arguments as to why the PBR Plan should be rejected, she also offers recommended modifications, should the Department approve a PBRM for NSTAR Gas (Attorney General Brief at 114-137; Attorney General Reply Brief at 37-54).

ii. PBR Term

The Attorney General argues that the Department has previously found that five-year terms are not long enough to achieve the efficiencies and benefits that a PBR Plan is expected to provide (Attorney General Brief at 114-115; Attorney General Reply Brief at 37-38). The

Attorney General references the Department's rejection of Boston Gas's proposed five-year term in D.P.U. 03-40 and the rejection of Bay State Gas's five-year term in D.P.U. 05-27, both in favor of ten-year terms, while also noting that both PBR plans were terminated early when found to not be working as intended (Attorney General Brief at 114-116; Attorney General Reply Brief at 37-38, 54). The Attorney General claims that the Company's reliance on recently approved electric distribution company PBR plans in D.P.U. 17-05 and D.P.U. 18-150 with five-year terms is tenuous and inapplicable, as NSTAR Gas is not an electric distribution company, and PBR plans for the two industries are wholly disparate (Attorney General Reply Brief at 37).

iii. Post Test Year Capital Additions

The Attorney General maintains that NSTAR Gas has failed to provide a legitimate basis for the Department to depart from its longstanding precedent (Attorney General Brief at 19). The Attorney General contends that, even if the Department approves the Company's proposed PBRM, an exception to the post-test-year standard on rate base additions is not appropriate (Attorney General Brief at 14, citing D.P.U. 96-50-C (Phase I) at 16-17; D.P.U. 96-50 (Phase I) at 15).

According to the Attorney General, the Company's 2019 plant investments compared to its history from 2015 through 2018 undermines the argument that the carrying cost of these post-test-year investments would amount to a significant burden (Attorney General Brief at 16-17). The Attorney General also dismisses the Company's concern that the ESM in its proposed PBRM will be triggered if the Department does not allow the inclusion of 2019 and

2020 capital additions in rate base (Attorney General Brief at 16, citing Company Brief at 73; Tr. 6, at 711-715). According to the Attorney General, even if the Department were to approve the Company's proposed PBRM, there should be no concern about triggering the ESM because of: (1) the revenue growth from growth-related capital additions; (2) the reduction in NSTAR Gas's costs associated with the acquisition of Bay State's operations; (3) the expected zero growth in operations and maintenance expenses; and (4) basic prudent budget management (Attorney General Brief at 16, 23-24, 61-63).

Additionally, the Attorney General rejects the Company's claim that post-test-year investments should be included in rate base because "increasing investment is projected to continue" (Attorney General Reply Brief at 6, citing Company Brief at 50, 70, 72). In particular, she notes that the Company did not provide project proposals, budgets, or approvals to support the necessity, the prudence, or the dollar amount associated with the claimed spending for the years 2020 through 2025 (Attorney General Reply Brief at 6). Further, the Attorney General points out that the Company's list of projects anticipated to be in service in 2020 was $25.17 million, $10 million short of the Company's predicted amount of $35.9 million (Attorney General Reply Brief at 6, citing Exh. DPU-ES 33-18). She claims that the same shortfall of anticipated in-service projects exists for 2021, as evidenced by a comparison between the estimated spend of $26.3 million and projected spend of $50.1 million (Attorney General Reply Brief at 6-7, citing Exh. DPU-ES 33-18).

Moreover, the Attorney General argues that the Company's reliance on the Department's decision in D.P.U. 18-150 to justify the departure from precedent ignores the basis for that decision, which she claims was National Grid's transitioning from traditional cost of service ratemaking with a capital tracker to a PBRM (Attorney General Brief at 16; Attorney General Reply Brief at 4). The Attorney General argues that NSTAR Gas, unlike National Grid, is not transitioning from a capital tracker to a PBRM, but simply is seeking to roll into rate base investments made since its last base distribution rate case (Attorney General Brief at 16).

Regarding the Company's proposed roll-in of 2020 non-GSEP capital additions in its first PBR adjustment, the Attorney General asserts that the Company also fails to meet the Department's post-test year adjustment standard (Attorney General Brief at 19). Moreover, the Attorney General argues that the Company has not provided any documentation regarding the 2020 additions and concludes that they are neither known and measurable nor shown to be significant (Attorney General Brief at 19).

iv. X Factor

(A) Introduction

The Attorney General claims that the Company's proposed X factor is unreasonable, and she calculates her own using various alternatives to the Company's TFP study parameters and methodology (Attorney General Brief at 118, 125; Attorney General Reply Brief at 39-40). With respect to the Company's TFP study, the Attorney General raises specific concerns regarding: (1) the treatment of Customer Service and Information ("CS&I") expense; (2) the chosen sample/peer group; (3) the use of allegedly flawed data; and (4) the benchmark year selection (Attorney General Brief at 120-125; Attorney General Reply Brief at 41-45). The Attorney General proposed an X factor of -0.69 percent based on her alternative methodology (Attorney General Brief at 126).[29]

(B) Treatment of CS&I Expenses

The Attorney General alleges that the Company's inclusion of CS&I expenses is inappropriate and biases the X factor in favor of NSTAR Gas (Attorney General Brief at 120-121; Attorney General Reply Brief at 41-42). The Attorney General notes that some, but not all, LDCs include demand-side management ("DSM") expenses under the CS&I expense category, and that DSM expenses are not itemized or easily identifiable (Attorney General Brief at 120, citing Exhs. ES-JF/MF-Rebuttal-1, at 25-27; AG-MNL-Surrebuttal at 4; AG 9-10; Tr. 7, at 912-915; Attorney General Reply Brief at 41-42). While the Company excluded its own DSM expenses from its TFP study, the Attorney General contends that the inclusion of CS&I expenses for other companies likely includes DSM expenses, which have grown rapidly for many LDCs during the 15-year study timeframe (Attorney General Brief at 121; Attorney General Reply Brief at 41-42). Based on the divergent reporting and potential magnitude of DSM expenses, the Attorney General maintains that CS&I expenses should be excluded from TFP studies, as they were in the productivity studies sponsored by electric distribution companies in their recent PBR proposals (Attorney General Brief at 121, citing Exhs. AG-MNL-1, at 13; AG-MNL-Surrebuttal at 4).

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29 The X factor computed by the Attorney General uses a national industry sample/peer group, which was adjusted to exclude CS&I expenses and alleged problematic data (Attorney General Brief at 126).

To support her claim that inclusion of CS&I expense has a material effect on the X factor, the Attorney General points to the Company's updated X factor after removing DSM expenses for three additional Massachusetts LDCs, which increased by 12 basis points (Attorney General Reply Brief at 41-42). The Attorney General contends that DSM expenses are still included for other LDCs in the regional sample in the instances where they are included under CS&I expense, and, as such, they skew the X factor results to be more negative (Attorney General Reply Brief at 42).[30]

(C) Peer Group Selection (national vs. regional)

The Attorney General argues that the regional sample group is not an appropriate peer group for the Company and that the national sample should be used to set the X factor (Attorney General Brief at 122; Attorney General Reply Brief at 43). The Attorney General notes that in recent PBR proceedings before the Department, X factors were determined based on a national peer group, but that here the Company shifts to the sample group that provides a more favorable X factor to NSTAR Gas (Attorney General Brief at 123; Attorney General Reply Brief at 43).

While the Company defends the use of a regional group because of differences in economies of scale and output growth between the regional and national group, the Attorney General claims that NSTAR Gas's customer growth is more aligned with the national group and that empirical evidence related to the effects of LDC size and economies of scale were

30 The Attorney General maintains that increased energy savings resulting from increased DSM and CS&I expenses are not captured in the study's output metric, which causes skewed TFP results (Attorney General Brief at 121).

not provided (Attorney General Brief at 122; Attorney General Reply Brief at 43-44). The Attorney General also challenges the Company's assertion that a regional group is more appropriate based on the higher composition of leak-prone mains in the Northeast, noting that the cost to replace these mains are addressed and recovered through the Company's GSEP (Attorney General Brief at 122; Attorney General Reply Brief at 44). Moreover, the Attorney General contends that the TFP growth of the Northeast region is likely slowed by the replacement of cast iron and bare steel mains and that this further supports the use of a national peer group (Attorney General Brief at 123, citing Exh. AG-MNL-Surrebuttal, at 17; Attorney General Reply Brief at 44-45).

(D) Use of Allegedly Flawed Data

The Attorney General maintains that some of the data used in the Company's TFP study is problematic and ran her own TFP study which, among other changes, removed the alleged problematic data (Attorney General Brief 123-124; Attorney General Reply Brief at 42). Specifically, the Attorney General asserts that the Company's study included LDCs with data that was compromised by merger, acquisition, and divestiture problems (Attorney General Brief at 123, citing Exh. ES-JF/MF-Rebuttal-1, at 35-36). The Attorney General claims that NSTAR Gas has not adequately defended the use of such data, and that the Company's suggestion that aggregating data would obviate any potential issues is incorrect (Attorney General Brief at 123; Attorney General Reply Brief at 42-43).

(E) TFP Study Benchmark Year

The Attorney General argues that the use of a recent benchmark year is suboptimal, as the accuracy of the capital quantity index is improved when the benchmark year is as early as possible (Attorney General Brief at 124, citing Exhs. AG-MNL-1, at 8-9; AG-MNL-3, at 31). The Attorney General notes that the Company's benchmark year of 1998 is only five years before the start of the study sample period, whereas the benchmark year in the recent National Grid PBR proposal was 1964 (Attorney General Brief at 124; Attorney General Reply Brief at 43). The Attorney General contends that by assuming the same system age for all LDCs as part of its TFP study despite the Northeast having older systems, estimated productivity growth is slowed, and that the use of a recent benchmark year only exacerbates this problem (Attorney General Brief at 124-125; Attorney General Reply Brief at 43).

v. Consumer Dividend

(A) Introduction

The Attorney General states that the Company's exclusion of a consumer dividend is based on NSTAR Gas's econometric benchmarking study, which purports to show that the Company is a relatively efficient cost performer compared to its peers (Attorney General Brief at 127; Attorney General Reply Brief at 49). The Attorney General raises several concerns regarding the Company's benchmarking study, including: (1) the benchmark year selection and timeframe; (2) the inclusion of CS&I expenses; (3) the study sample timeframe; (4) the manner in which prices are levelized; and (5) the complexity of the benchmarking study (Attorney General Brief at 127-131). Based on her own benchmarking analysis that attempts to address her concerns, the Attorney General argues that NSTAR Gas's cost performance was merely average amongst its peers (Attorney General Brief at 132, citing Exh. AG-MNL-3, at 53). The Attorney General contends that average cost performance is commensurate with a consumer dividend of 0.3 to 0.4 percent, and that it is both improper and unusual to claim that no consumer dividend is warranted unless a company is a markedly superior cost performer (Attorney General Brief at 132; Attorney General Reply Brief at 49). The Company, the Attorney General argues, is simply not a superior cost performer (Attorney General Reply Brief at 49).

(B) Benchmark Year and Timeframe

With respect to the chosen benchmark year, the Attorney General voices the same concerns for the benchmarking study as the TFP study regarding the recency of the benchmark year and the potential for it to skew the accuracy of results (Attorney General Brief at 127; Attorney General Reply Brief at 40-41, 43). Regarding the benchmarking timeframe, the Attorney General contends that the latest benchmarking year of 2017 is only three years before the first year of the proposed PBR Plan, and she takes issue with the exclusion of the Company's 2018 test-year costs from the study (Attorney General Brief at 129).

(C) Treatment of CS&I Expenses

As in the case of the TFP study, the Attorney General disagrees with the inclusion of CS&I costs in the Company's benchmarking study, claiming that the inclusion throws into question the entire LDC ranking since the Company is unable to determine how many of the LDCs in the sample had DSM program expenses (Attorney General Brief at 128, citing Exh. AG 9-10). The Attorney General further indicates that, if CS&I costs are removed, the Company's cost performance ranking drops from the first quartile to the second quartile (Attorney General Brief at 129, citing RR-DPU-21, at 3; Attorney General Reply Brief, at 49, citing RR-DPU-21, at 3).

(D) Sample Timeframe

The Attorney General asserts that the Company's benchmarking study needlessly restricted the sample period for its econometric work, and that a longer sample period would have improved the precision of the model estimates and predictions (Attorney General Brief at 129, citing Exh. AG-MNL-3, at 44). In response to the Company's claim that a shorter time series was examined to measure current efficiency of each firm relative to its peers, the Attorney General indicates that a longer period could have been used if a trend variable were added to the cost model (Attorney General Brief at 129). The Attorney General claims that the restricted timeframe is not standard practice in econometric cost benchmarking studies (Attorney General Brief at 129, citing Exh. AG-MNL-3, at 44).

(E) Price Levelization

The Attorney General contends that the Company improperly levelized input prices, such that differences in price levels faced by LDCs were poorly measured (Attorney General Brief at 129). As an example, the Attorney General contends that for certain years labor and construction prices were assumed to be the same for all utilities, whereas in other years prices differed slightly if regional price trends differed (Attorney General Brief at 129). The Attorney General claims that this treatment of prices is unusual in econometric utility cost research (Attorney General Brief at 129).

(F) Complexity of Benchmarking Model

The Attorney General insists that the Company's benchmarking model is unnecessarily complex, utilizing a multi-equation model with a cost share equation and cost function, as well as quadratic and interaction terms for certain variables (Attorney General Brief at 130, citing Exhs. ES-JF/MF-3, at 20-21; AG 37-1, (Supp.) Att. at 28). The Attorney General argues that the complexity, along with the short sample period, results in variables with few statistically significant parameter estimates (Attorney General Brief at 130-131).

vi. Earnings Sharing Mechanism

The Attorney General opposes the Company's symmetrical ESM, stating that it punishes ratepayers by sharing the costs if productivity gains are lackluster (Attorney General Brief at 133). Additionally, the Attorney General insists that the ESM will not prevent NSTAR Gas from overearning, but simply will limit the amount of overearning and double recovery (Attorney General Reply Brief at 50). Because any sharing with ratepayers would not occur until earnings surpassed the 100-basis point deadband, the Attorney General alleges that the Company could over earn by approximately six to eight million dollars a year before needing to return some of the over earnings to customers (Attorney General Reply Brief at 50). If the Department is to approve the Company's PBR Plan, the Attorney General recommends that the Department adopt an asymmetrical ESM where sharing only occurs if the Company's ROE is 100-basis points above the allowed ROE (Attorney General Brief at 134). In support of her recommendation, the Attorney General refers to the asymmetrical ESMs approved by the Department in recent PBR proposals (Attorney General Brief at 134, citing D.P.U. 18-150, at 70; D.P.U. 17-05, at 401).

vii. Double Recovery of Capital Costs

The Attorney General alleges that the Company's PBR Plan allows for double recovery of certain capital addition costs, namely those associated with leak-prone pipe replacement recovered through the GSEP (Attorney General Brief at 135-136; Attorney

General Reply Brief at 45). The Attorney General states that a comprehensive PBR proposal includes the recovery of all capital and, therefore, a PBR proposal with a capital tracker like the GSEP will inevitably lead to double recovery (Attorney General Brief at 135-136; Attorney General Reply Brief at 46). The Attorney General notes that the Company's affiliate, NSTAR Electric Company ("NSTAR Electric"), recognized in its their proposal in D.P.U. 17-05 that a utility should have a capital tracker or a PBR plan, but not both (Attorney General Brief at 137).

Moreover, the Attorney General rejects the Company's claims that without the GSEP the Company would not replace, nor would base rates provide recovery for, any leak-prone mains or services (Attorney General Brief at 135; Attorney General Reply Brief at 47). She avers that the Company has been replacing leak-prone pipe since its inception and certainly before the GSEP was put in place (Attorney General Brief at 135; Attorney General Reply Brief at 47).

b. DOER

DOER acknowledges the Department's precedent approving PBRMs in the past for distribution companies, and notes that approval of such a mechanism should rest on a finding that it will result in just and reasonable rates (DOER Brief at 2). DOER does not comment on the individual elements of the Company's proposed PBRM on brief, but defers to the Department in evaluating the reasonableness of the proposal (DOER Brief at 13-14).

c. DOD-FEA

DOD-FEA argues that the Company's proposed PBRM should be rejected in its entirety (DOD-FEA Brief at 28, 31). DOD-FEA contends that the PBR proposal will erode customer protections as rates will increase without any formal cost of service reviews and that customers will not have an opportunity to contest the reasonableness of rates (DOD-FEA Brief at 28-29). Further, DOD-FEA asserts that PBR is not designed to work in conjunction with the Company's LDAC and GSEP (DOD-FEA Brief at 29). According to DOD-FEA, the proposed PBRM accomplishes nothing more than create a simple administrative means to adjust rates between rate cases, and administrative ease should not come at the expense of customer protections and reasonable rates (DOD-FEA Brief at 30). DOD-FEA stresses that rates should be based on known and measurable cost changes (DOD-FEA Brief at 31).

DOD-FEA contends that traditional ratemaking creates stronger incentives than PBR to manage and contain costs, as the Company would need to reduce operating expenses below the test year level of costs in order to enhance profits (DOD-FEA Brief at 31-32). In contrast, under the PBRM, DOD-FEA states that rates would adjust annually based on forecasts that have no direct relationship to the Company's actual costs, allowing the Company to earn more than the Department's authorized return (DOD-FEA Brief at 31-32).

d. TEC

TEC argues that the Company's proposed PBRM is flawed and should be rejected (TEC Brief at 6). TEC indicates that the flaws include, but are not limited to: (1) an overly broad exogenous cost factor; (2) potential capital additions without customer safeguards; (3) an ESM that heavily favors NSTAR Gas; and (4) the potential for overlap with the GSEP (TEC Brief at 6).

Regarding the exogenous cost factor, TEC takes issue with the recovery of costs relating to future standards or practices for gas pipeline safety directives, arguing that such expenses should not trigger an exogenous cost event, as safety is a core function of running a gas utility (TEC Brief at 6-7). TEC also asserts that an exogenous cost factor should only recover costs that are truly unforeseeable and beyond the Company's control, and should not incentivize the Company to be indifferent to changes where it may have some degree of control or legal recourse (TEC Brief at 7).

TEC also raises concerns with the Company's proposal to roll in capital additions since the start of the PBR term if the five-year term is extended to a ten-year term (TEC Brief at 7; TEC Reply Brief at 9, 11). TEC argues that the Department has a responsibility to ratepayers to ensure that capital additions are prudent and that any future roll-in should occur only through a base distribution rate proceeding (TEC Brief at 7). TEC contends that a base distribution rate proceeding after five years would give the Department an opportunity to evaluate the PBRM and that any capital addition roll-in with limited oversight would set bad precedent (TEC Brief at 7-8; TEC Reply Brief at 10).

TEC echoes the Attorney General's concerns regarding the ESM, noting that as proposed it functions as a form of ROE insurance for NSTAR Gas (TEC Brief at 8). TEC suggests that if an ESM is approved, it should be asymmetric with over earnings refunded to ratepayers (TEC Brief at 8). TEC also echoes the Attorney General's concerns regarding the potential for the PBRM to overlap with reconciling mechanisms, and suggests that the Department examine any potential effect on the X factor (TEC Brief at 7). TEC argues that the X factor approved must be high enough to protect ratepayers and incentivize efficient operation by the Company (TEC Brief at 8-9).

e. Company

i. Introduction

NSTAR Gas argues that its proposed PBR Plan will create a strong economic incentive for the Company to manage its costs, provide the flexibility and predictability necessary to face the near-term uncertainties facing the natural gas industry, and maintain safe and reliable service (Company Brief at 17-18, 21-23; Company Reply Brief at 2-3). The Company rejects claims made by intervenors that the PBR Plan erodes customer protections and avers that Department oversight will increase with annual compliance filings (Company Brief at 76-77). The Company argues that its proposal is consistent with Department precedent that has previously found that PBR is appropriate as an alternative to traditional ratemaking to address a changing operating environment and higher customer expectations (Company Brief at 16, 23, citing D.P.U. 18-150, at 53; Company Reply Brief at 29). The Company identifies a variety of challenges, including the changing operating environment for LDCs, the need to address environmental impacts, and the step-up in safety requirements resulting from the Merrimack Valley incident,[31] and claims that the PBR will best support the Company in addressing these challenges (Company Brief at 23).

[31] On September 13, 2018, Bay State experienced an overpressurization of its low-pressure distribution system serving the City of Lawrence and the towns of Andover and North Andover in the Merrimack Valley. National Transportation Safety Board Pipeline Accident Report, NTSB/PAR-19/02 (NTIS No. PB2019-101365), adopted September 24, 2019 ("NTSB Report") at 1. The overpressurization allowed gas from a high-pressure distribution system to enter the

The Company asserts that the PBR formula is derived through economic analysis of utility cost trends and that the revenue-per-customer cap is designed to work in tandem with the revenue decoupling mechanism approved in D.P.U. 14-150 (Company Brief at 18, 24). NSTAR Gas contends that the benefits of the proposed PBR Plan include the reduction in regulatory costs and burden, lower customer costs in the long term, and enhanced operations and safety (Company Brief at 22-23). NSTAR Gas maintains that the proposed PBR Plan will provide benefits for both customers and the Company and that it should be approved as proposed (Company Brief at 21-23; Company Reply Brief at 23-24).

ii. PBR Term

The Company argues that the proposed five-year PBR term and potential five-year extension will reduce regulatory burden and associated customer costs, indicating that, without a PBR plan, the Company anticipates needing to file a base distribution rate proceeding every other year (Company Brief at 46-47; Company Reply Brief at 10, 26). With a five-year term beginning November 1, 2020 and ending October 31, 2025, the Company insists that the PBR Plan would avoid at least two rate cases (Company Brief at 47, citing Exh. ES-WJA/DPH-1, at 93, 94). NSTAR Gas contends that the five-year term provides the appropriate incentives for cost savings and operational efficiencies (Company Brief at 47, 55; Company Reply Brief at 4-5). The Company asserts that its proposal is consistent with the Department's decision in D.T.E. 03-40 to impose a ten-year PBR plan

low-pressure distribution system. NTSB Report at 1. This lack of proper system regulation resulted in the damage or destruction of 131 homes and businesses, the hospitalization of 22 individuals, and the death of one person. NTSB Report at 1.

with a mid-point review to determine if the plan should continue or be terminated (Company Reply Brief at 4). Moreover, the Company contends that the Attorney General's reliance on Department precedent from almost ten years prior to suggest that a five-year term is too short is inapposite, as the current challenges facing the natural gas industry are different (Company Reply Brief at 5). The Company also indicates that any extension of a second five-year term would be subject to Department oversight (Company Reply Brief at 26).

i. Post Test Year Capital Additions

NSTAR Gas argues that the rate base roll-ins associated with 2019 and 2020 plant are appropriate and critical to the proposed PBR Plan (Company Brief at 67, 72). As an initial matter, the Company rejects the Attorney General's assertions that she was not afforded due process with respect to the 2019 non-GSEP capital additions, arguing there was ample time to review and respond to the Company's proposed 2019 capital additions prior to evidentiary hearings (Company Brief at 68-69). The Company further argues that the Attorney General retained, at customers' expense, an expert consultant whose sole purpose in the proceeding was to assist in the review of the Company's capital additions, including the 2019 non-GSEP investments (Company Brief at 69). NSTAR Gas maintains that the Attorney General had ample time to review the 2019 non-GSEP investment documentation and, as such, there has been no infringement of her rights under G.L. c. 30A, § 11 (Company Brief at 69-70).

NSTAR Gas contends that, contrary to the Attorney General's argument, even when combined with the potential PBR revenues, the cost of carrying the non-GSEP investment is insufficient to offset the potential PBR revenues, even when coupled with customer growth revenues (Company Reply Brief at 31, citing Tr. 6, at 807; RR-DPU-3; RR-DPU-4; RR-DPU-16). In addition, the Company states that the opportunity to earn revenues from new business is in decline and expected to further diminish due the increasing cost of connecting customers (Company Reply Brief at 32). In particular, the Company notes that between 2015 and 2019 there were 2,300 customers requesting gas service that were not connected due to required contributions in aid of construction ("CIACs") (Company Reply Brief at 32).

The Company insists that the main driver for its PBR Plan is the unprecedented level of capital investments that it has made and will continue to make (Company Brief at 70). NSTAR Gas claims that rate base increased by nearly 90 percent since the Company's last base distribution rate proceeding and that the PBR Plan was designed to address the most significant cost pressures facing the Company (i.e., capital investments) (Company Brief at 70, 72). By incorporating the 2019 non-GSEP capital additions into base distribution rates for effect November 1, 2020, and the 2020 non-GSEP capital additions on November 1, 2021, the Company claims that it will be able to potentially avoid a base distribution rate proceeding for a period of longer than five years (Company Brief at 70, 72, citing Exh. ES-DPH/ANB-1, at 10). Moreover, the Company argues that excluding the capital additions would dilute, if not entirely defeat, the purpose of a shift from traditional cost of service regulation to incentive regulation and insists that the revenue support provided by the PBR adjustments, as well as any potential growth in customer revenues, would be insufficient to support necessary capital investments during the PBR term (Company Brief at 73, citing RR-DPU-15; RR-DPU-16).

Regarding the 2020 non-GSEP capital roll-ins, NSTAR Gas contends that it will file the necessary project documentation with the Department on April 1, 2021, prior to the first annual PBR rate adjustment filing on August 1, 2021, for rates effective November 1, 2021, to provide ample time for review (Company Brief at 75, citing Exh. DPU-ES 7-3). The Company maintains that it is not seeking pre-approval of cost recovery associated with these projects prior to the Department's conducting a prudence review and, as such, the 2020 non-GSEP capital additions will undergo a proper review prior to inclusion in rates (Company Brief at 76).

Moreover, the Company argues that in order for the PBRM to continue for a second five-year term, it is essential to include the revenue requirement associated with the 2021 through 2024 investments in base distribution rates in year five of the PBR term (Company Brief at 79). Accordingly, NSTAR Gas maintains that it would notify the Department in the September 15, 2024 compliance filing whether it intends to continue the PBRM for a second five-year term or file for a base distribution rate increase for effect November 1, 2025 (Company Brief at 54, citing Exh. ES-WJA/DPH-1, at 99).

ii. X Factor

(A) Introduction

NSTAR Gas argues that the proposed X factor of -1.18 percent is reasonable and adequately supported by the record (Company Brief at 36, 55; Company Reply Brief at 12). According to the Company, the X factor is the productivity offset based on an industry TFP study, where the resulting factor represents a rate of growth for efficiency that the Company must achieve in order to earn its allowed rate of return (Company Brief at 26-27, citing Exh. DPU-ES 22-11). The Company avers that it appropriately adjusted the TFP study to ensure that energy efficiency program costs for all Massachusetts LDCs were removed and that there is no valid reason to reject the proposed PBR Plan or X factor (Company Brief at 26, n.8, 56). The Company argues that none of the Attorney General's critiques of its TFP study are persuasive and that the Department should reject her recommended X factor of -0.69 (Company Brief at 55, 60; Company Reply Brief at 12-16).

(B) Treatment of CS&I Expenses

The Company argues that the Attorney General's proposal to exclude CS&I expenses from the TFP study is inappropriate and, moreover, fails to solve the alleged concerns surrounding DSM programs (Company Reply Brief at 18). NSTAR Gas contends that while the Attorney General's witness did not observe trends in DSM expenses over time, data published in the American Council for an Energy-Efficient Economy reports demonstrate DSM expenses have been declining over time (Company Reply Brief at 19, citing Tr. 11, at 1446-1450, 1452-1453). The Company asserts that CS&I expenses as a whole have been rising over time, which invalidates the Attorney General's claim that DSM expenses are a majority of the costs included in CS&I expense (Company Reply Brief at 19, citing Exh. AG 44-6). Further, the Company argues that this evidence supports the fact that CS&I expense contains legitimate costs that should be included in the TFP study (Company Reply Brief at 19).

(C) Peer Group Selection (national vs. regional)

NSTAR Gas argues that the regional peer group is most appropriate for determining the X factor and that the Attorney General's recommendation of a national peer group is simply results driven and not based on methodological principles (Company Reply Brief at 14). NSTAR Gas insists that trends experienced by the Northeast regional peer group are most similar to the actual experiences of the Company and, therefore, will result in the most accurate X factor (Company Reply Brief at 15). The Company argues that differences between the regional and national TFP trends are due to regional drivers such as the presence of cast iron and bare steel mains, economies of scale, technology, and output growth (Company Reply Brief at 15-16). NSTAR Gas maintains that TFP trends for the Northeast region are slower overall due to capital input trends, OM&A input trends, and output trends overall (Company Reply Brief at 16, citing Tr. 6, at 930-932). Moreover, the Company contends that use of a regional peer group is consistent with Department precedent for determining LDC X factors (Company Brief at 35, citing D.T.E. 03-40, at 475; Company Reply Brief at 15).

(D) Use of Allegedly Flawed Data

The Company rejects the Attorney General's allegations that the TFP study relies on flawed data, stating that her assertions are wrong and should be disregarded (Company Brief at 59; Company Reply Brief at 14). In response to claims that data was compromised by mergers, acquisitions, and divestiture problems, NSTAR Gas contends that the Attorney General's witness failed to educate himself on the timing and implications of such events and that the Attorney General did not properly evaluate whether the associated data was appropriate to include in the TFP study (Company Brief at 59, citing Tr. 11, at 1464-1467; Company Reply Brief at 14). NSTAR Gas claims that the Attorney General arbitrarily excluded additional data associated with certain companies due to company size, and companies with perceived anomalies without fully understanding the data or properly supporting the exclusions (Company Brief at 59, citing Tr. 11, at 1460).

(E) TFP Study Benchmark Year

NSTAR Gas asserts that the proposed benchmark year was chosen to include a greater cross-section of quality, reliable utility data, as well as to account for the change in focus to replacement of leak-prone pipe (Company Brief at 60; Company Reply Brief at 17, citing Exh. AG 9-1). The Company contends that the Attorney General's proposal to use an earlier benchmark would result in a sizable loss of companies in the study due to unreliable or incomplete data (Company Brief at 59-60). Moreover, the Company asserts that the Attorney General's claim that a more recent benchmark compromises the accuracy of the study results is not supported by record evidence (Company Reply Brief at 16).

The Company also contends that quantitative analysis demonstrates that an earlier benchmark year would not have a material impact on the TFP growth rate of NSTAR Gas (Company Reply Brief at 17, citing Exh. ES-JF/MF-Rebuttal-1, at 21-23). Moreover, the Company avers that the Attorney General's witness recently used a similar period of time between the benchmark and start year for another client's LDC TFP study (Company Reply Brief at 17, citing Tr. 11, at 1479).

iii. Consumer Dividend

NSTAR Gas argues that, because it is already a relatively efficient cost performer, a consumer dividend, or any additional stretch factor, is unwarranted (Company Brief at 36-37, 60; Company Reply Brief at 20). In response to the Attorney General's recommendation of a consumer dividend between 0.3 and 0.4 percent, the Company claims that these figures are not supported by record evidence (Company Brief at 63; Company Reply Brief at 20). The Company maintains that record evidence is required to approve such a quantification or finding (Company Brief at 63; Company Reply Brief at 20).

The Company rejects the Attorney General's critiques of the Company's benchmarking model and insists that the analysis presented by the Attorney General has its own issues (Company Brief at 61). NSTAR Gas contends, for example, that the Attorney General relied on more granular labor price inputs that required additional unsupported assumptions that raise doubts regarding the reliability of the inputs and outputs (Company Brief at 61, citing Exh. ES-JF/MF-Rebuttal-1, at 42-44). NSTAR Gas claims that the Attorney General confuses granularity for accuracy and asserts that the Company opted to focus on data that was as accurate as possible (Company Brief at 61).

NSTAR Gas acknowledges that the Attorney General's reference to the econometric total cost benchmarking and resulting stretch factor assignment relied upon in Ontario (Company Reply Brief at 21-22, citing Exh. AG-MNL-1, at 17). Examining its performance, which it argues was 13 percent more efficient than average for the years 2014 through 2017, NSTAR Gas contends that if the Ontario criteria were applied, the Company's performance would align with a stretch factor of 0.15 percent, rather than the 0.3 to 0.4 percent suggested by the Attorney General (Company Reply Brief at 21-22).

iv. Earnings Sharing Mechanism

NSTAR Gas argues that the proposed ESM is not only reasonable, but appropriately balances shareholder and ratepayer risk during the PBR term (Company Brief at 64, 80; Company Reply Brief at 22). The Company indicates that the symmetrical ESM allows for a correction if actual costs fall out of alignment during the PBR term and provides customers with a near-term benefit if earnings reach a level above the deadband (Company Brief at 45, 65; Company Reply Brief at 22, 24-25). NSTAR Gas contends that the ESM preserves the incentives of the PBR Plan and provides a level of assurance during a time of great uncertainty for the gas industry in Massachusetts (Company Brief at 45).

NSTAR Gas dismisses the intervenors' assertion that the ESM erodes customer protections and maintains that the ESM will protect customers against inaccurate cost projections (Company Reply Brief at 24-25). The Company insists that benefits will inure largely to customers as the proposed sharing is on a 75-percent and 25-percent basis for ratepayers and shareholders, respectively (Company Brief at 46, 65). Moreover, the Company claims that, prior to D.P.U. 17-05, every PBR approved by the Department included a symmetrical deadband (Company Brief at 64).

v. Exogenous Cost Factor (Z Factor)

The Company maintains that the Z factor is a necessary component of the PBRM as it accounts for operating cost changes that arise from factors beyond the Company's control (Company Brief at 40). NSTAR Gas observes that the Department has consistently established exogenous cost provisions within approved PBR plans and maintains that exogenous events can cause positive or negative cost changes that are not otherwise reflected in GDP-PI (Company Brief at 40). The Company avers that the significance threshold of $700,000 is consistent with Department precedent (Company Brief at 41).

Regarding the second set of criteria for exogenous cost changes, NSTAR Gas argues that the two-part Z factor is necessary to address uncertainty in the industry, including increases in future pipeline safety requirements (Company Brief at 42-43). In response to TEC's assertion that the Z factor qualification criteria are overly broad, the Company insists that such an argument stems from a misunderstanding of the costs for which the Company has any control (Company Brief at 77-78).

vi. Double Recovery of Capital Costs

NSTAR Gas maintains that there will be no double recovery of GSEP-eligible costs, as the X factor in the PBR formula and the cost recovery associated with the GSEP represent two distinct aspects of the utility regulatory paradigm (Company Brief at 65; Company Reply Brief at 8, citing Exh. ES-JF/MF-1, at 46). The GSEP, the Company argues, is only designed to provide for the accelerated replacement of leak-prone pipe to achieve safety and policy goals and is not a comprehensive capital recovery mechanism (Company Brief at 65). The Company states that the PBR formula will be applied annually to a revenue requirement that accounts for all capital additions made to date, regardless of past treatment, and that such treatment assures there is no possibility of double recovery of past GSEP projects (Company Brief at 39, 66, citing Exh. DPU-ES 32-14). Additionally, the Company argues that the

PBRM does not recover specific costs but, instead, provides revenue adjustments in accordance with the PBR formula on a forward basis (Company Brief at 66).

According to the Company, there is no risk of double recovery only the potential for a revenue stream that is greater than the Company's costs (Company Brief at 66). NSTAR Gas asserts that such concerns are unwarranted because the level of capital funding provided by the PBR formula will still be less than the revenue requirement needed to support its capital investment based on its projected level of future capital spending and funding (Company Brief at 39, 66, citing Exh. DPU-ES 32-14; Company Reply Brief at 8). Moreover, the Company argues that if the combination of the PBR and GSEP result in a revenue stream greater than the Company's overall costs, the proposed ESM will return a portion of those overearnings to customers (Company Brief at 39-40, 58; Company Reply Brief at 8).

4. Analysis and Findings

a. Introduction

In the sections below, we review our ratemaking authority and reaffirm that, pursuant to G.L. c. 164, § 94, the Department may implement PBR as an alternative to cost of service/rate of return regulation. Further, we discuss the factors that the Department has used to review incentive regulation proposals. Finally, we review the Company's PBR Plan to determine whether it is in the public interest and will result in just and reasonable rates.

b. Department Ratemaking Authority

Pursuant to G.L. c. 164, § 94, the Legislature has granted the Department extensive ratemaking authority over electric and gas distribution companies. The Supreme Judicial

Court has consistently found that the Department's authority to design and set rates is broad and substantial. See, e.g., Boston Real Estate Board v. Department of Public Utilities, 334 Mass. 477, 485 (1956). Because G.L. c. 164, § 94, authorizes the Department to regulate the rates, prices, and charges that electric and gas distribution companies may collect, this authority includes the power to implement revenue adjustment mechanisms such as a PBR. Boston Gas Company v. Department of Telecommunications and Energy, 436 Mass. 233, 234-235 (2002).

The Department is not compelled to use any particular method to establish rates, provided that the end result is not confiscatory (i.e., deprives a distribution company of the opportunity to realize a fair and reasonable return on its investment). 375 Mass. 1, 19. The Supreme Judicial Court has held that a basic principle of ratemaking is that "the department is free to select or reject a particular method as long as its choice does not have a confiscatory effect or is not otherwise illegal." American Hoechest Corporation v. Department of Public Utilities, 379 Mass. 408, 413 (1980), citing 376 Mass. 294, 302.

In addition, G.L. c. 164, § 76, grants the Department broad supervision over electric and gas distribution companies. Under G.L. c. 164, § 76, the Department has the authority to establish reasonable rules and regulations consistent with G.L. c. 164, as needed, to carry out its administration of jurisdictional companies in the public interest. D.P.U. 07-50-B at 26-27. See also Cambridge Electric Light Company v. Department of Public Utilities, 363 Mass. 474, 494-496 (1973).

Although the Department traditionally has relied on cost of service/rate of return regulation to establish just and reasonable rates, there are many variations and adjustments in the specific application of this model to individual utilities as circumstances differed across companies and across time. D.P.U. 07-50, at 8. Over the years, electric and gas distribution companies subject to the Department's jurisdiction have operated under PBR or PBR-like plans. See, e.g., D.P.U. 18-150, at 47; D.P.U. 17-05, at 371-372; D.T.E. 05-27, at 382; D.T.E. 03-40, at 471; The Berkshire Gas Company, D.T.E. 01-56, at 10 (2002); Massachusetts Electric Company/Eastern Edison Company, D.T.E. 99-47, at 4-14 (2000).

Consistent with the discussion above, the Department reaffirms that we may implement PBR as an alternative to cost of service/rate of return regulation under the broad ratemaking authority granted to us by the Legislature under G.L. c. 164, § 94.[32] The Department reviews the Company's specific PBR proposal under the standards set forth below.

c. Evaluation Criteria for PBR

The Department must approach the setting of rates and charges in a manner that: (1) meets our statutory obligations under G.L. c. 164, § 94, to ensure rates that are just and reasonable, not unjustly discriminatory, or unduly preferential; and (2) is consistent with long-standing ratemaking principles, including fairness, equity, and continuity. D.P.U. 07-50, at 10-11. Further, the Department must establish rates in a manner that

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32 In addition, pursuant to G.L. c. 164, § 1E(a), the Department is authorized to promulgate rules and regulations to establish and require performance-based rates for gas and electric distribution companies.

balances a number of these key principles to reflect and address the practical circumstances attendant to any individual company's base distribution rate case. D.P.U. 07-50-A at 28. The Department has implemented PBRs or PBR-like mechanisms on a finding that such regulatory methods would better satisfy our public policy goals and statutory obligations. See, e.g., D.P.U. 96-50 (Phase I) at 261; D.P.U. 94-158, at 42-43; D.P.U. 94-50, at 139.

As part of our generic investigation of incentive ratemaking in D.P.U. 94-158, at 52-66, the Department examined the criteria by which PBR proposals for electric and gas distribution companies would be evaluated. The Department found that, because incentive regulation acts as an alternative to traditional cost of service regulation, incentive proposals would be subject to the standard of review established by G.L. c. 164, § 94, which requires that rates be just and reasonable. D.P.U. 94-158, at 52. Further, the Department determined that a petitioner seeking approval of an incentive regulation proposal like PBR is required to demonstrate that its approach is more likely than current regulation to advance the Department's traditional goals of safe, reliable, and least-cost energy service and to promote the objectives of economic efficiency, cost control, lower rates, and reduced administrative burden in regulation. D.P.U. 94-158, at 57. Finally, a well-designed incentive mechanism should provide utilities with greater incentives to reduce costs than currently exist under traditional cost of service regulation and should result in benefits to customers that are greater than would be present under current regulation. D.P.U. 94-158, at 57.

In addition to these criteria, the Department established a number of additional factors it would weigh in evaluating incentive proposals. D.P.U. 94-158, at 57. These factors provide that a well-designed incentive proposal should: (1) comply with Department regulations, unless accompanied by a request for a specific waiver; (2) be designed to serve as a vehicle to a more competitive environment and to improve the provision of monopoly services; (3) not result in reductions of safety, service reliability, or existing standards of customer service; (4) not focus excessively on cost recovery issues; (5) focus on comprehensive results; (6) be designed to achieve specific, measurable results; and (7) provide a more efficient regulatory approach, thus reducing regulatory and administrative costs. D.P.U. 94-158, at 58-64. The Department discusses these criteria and factors in the context of our evaluation of NSTAR Gas's PBR proposal in the subsections below.

d. Rationale for PBR

There is a fundamental evolution taking place in the natural gas local distribution industry in Massachusetts. This evolution has been driven, in large part, by two primary factors. First, the Commonwealth has instituted a number of legislative and administrative policy initiatives designed to address climate change and to foster a clean energy economy. An Act Relative To Green Communities, St. 2008, c. 169; An Act Establishing the Global Warming Solutions Act, St. 2008, c. 298 ("GWSA"); Green Communities Expansion Act, § 83A; Executive Order No. 569: Establishing an Integrated Climate Change Strategy for the Commonwealth (September 16, 2016). Second, the Merrimack Valley incident has prompted the industry and its regulators to reevaluate safety standards, practices, protocols, and procedures, to enhance safety and reliability of the natural gas distribution system (Exh. ES-WJA/DPH-1, at 34). An Act Further Providing for the Safety of the

Commonwealth's Natural Gas Infrastructure, St. 2018, c. 269. To varying degrees, this evolution is changing the operating environment for LDCs in Massachusetts.[33]

As described above, NSTAR Gas proposes to implement a PBRM that would adjust rates annually in accordance with a revenue cap formula (Exh. ES-WJA/DPH-1, at 8). The Company claims that a PBRM is a better fit than cost of service ratemaking for providing the Company with the revenue support it needs to address these changing industry dynamics (Exh. ES-WJA/DPH-1, at 14). Specifically, the cost control incentives and greater flexibility in relation to cost planning inherent in the PBR Plan will be beneficial in light of the Company's forecasted increase in both non-GSEP capital expenses and operating expenses to address changes in the industry operating environment (Exhs. ES-WJA/DPH-1, at 14, 23-29, 57; DPU-ES 3-5). Further, the Company claims that the PBR Plan is more administratively efficient and will, therefore, reduce administrative burden compared to cost of service ratemaking (Exhs. ES-WJA/DPH-1, at 13-14, 93-94; DPU-ES 3-5). For the reasons discussed below, the Department finds that NSTAR Gas has demonstrated that an alternative to traditional cost of service/rate of return ratemaking is warranted.

NSTAR Gas demonstrated that its system needs are changing and that its capital and operating costs are increasing in ways that it has not experienced in the past. The Company

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33 The Department notes that it has instituted an investigation to examine the role of LDCs in helping the Commonwealth to achieve its 2050 climate goals. Specifically, we will explore strategies to enable the Commonwealth to move into its net-zero emissions energy future while simultaneously safeguarding ratepayer interests; ensuring safe, reliable, and cost-effective natural gas service; and potentially recasting the role of LDCs in the Commonwealth. D.P.U. 20-80, at 1.

argues that there are two dynamics shaping the future of the natural gas industry across the United States: (1) the need to achieve the utmost level of public safety; and (2) the need to reduce methane emissions (Exh. ES-WJA/DPH-1, at 4-5).[34] The Company expects for these industry-wide changes to require substantial increases in capital investment and operating costs compared to prior periods, beyond what is already planned for GSEP-related activities (Exh. ES-WJA/DPH-1, at 24-35, 69). NSTAR Gas expects to see substantial increases in costs in four non-GSEP project categories: (1) pressure regulation modernization; (2) a low-pressure protection program; (3) system resiliency; and (4) system reliability investments (Exhs. ES-WJA/DPH-1, at 26-29; DPU-ES 3-12; DPU-ES 12-21; DPU-ES 33-13; DPU-ES 33-14; DPU-ES 33-15). This increased capital expense will impose significant financial pressure on the Company, and, the Company argues, the PBR Plan will provide a means of maintaining financial integrity for the PBR term (Exh. ES-WJA/DPH-1, at 95-96). Further, unlike a capital cost recovery mechanism, NSTAR Gas maintains that the proposed PBRM is designed to provide it with strong incentives to control costs (Exh. ES-WJA/DPH-1, at 13-14; DPU-ES 3-5).

The Department has allowed companies to adopt various capital cost recovery mechanisms in cases where a company has adequately demonstrated its need to recover incremental costs associated with capital expenditure programs between base distribution rate

34 The Company also mentions infrastructure constraints as a third concern for the Company and the industry, particularly in the Northeast region (Exhs. DPU-ES 3-5; DPU-ES 12-18).

cases. D.P.U. 15-155, at 40, 51-54; Fitchburg Gas and Electric Light Company, D.P.U. 15-80/D.P.U. 15-81, at 50 (2016); Boston Gas Company/Colonial Gas Company/Essex Gas Company, D.P.U. 10-55, at 121-122, 132-133 (2010); D.P.U. 09-39, at 79-80, 82; D.P.U. 09-30, at 133-134. The Department finds that a PBRM provides the Company more flexibility to address a changing operating environment (Exhs. ES-WJA/DPH-1, at 12-14; ES-WJA/DPH-1, at 21, 24-26, 34-35; DPU-ES 3-5). The approach we adopt addresses the need for increased non-GSEP capital investment and allows NSTAR Gas to best meet its public service obligations for providing safe, reliable, and least-cost service to customers as well as to ensure that the Commonwealth's emission reduction and pipeline safety goals are met. D.P.U. 94-158, at 57.

As part of the PBR Plan, the Company has committed to refraining from filing rate schedules to put new base distribution rates into effect during the PBR term (Exh. ES-WJA/DPH-1, at 93-94, 97-98; Tr. 3, at 381). The Department accepts that this stay-out provision will generate diminished administrative burden and will result in future efficiencies (Exhs. DPU-ES 3-5; DPU-ES 12-14; DPU-ES 12-15; DPU-ES 22-13). For instance, NSTAR Gas estimates that, without the PBRM, the Company would need to pursue a base distribution rate case every two years (Exhs. ES-WJA/DPH-1, at 93; DPU-ES 3-7; Tr. 3, at 380-382). Accordingly, the Department finds that the PBRM will result in a reduced administrative burden and is in the public interest as compared to other ratemaking and cost recovery mechanisms (Exhs. ES-JF/MF-1, at 17; ES-WJA/DPH-1, at 93-94).

Below, the Department addresses the PBRM formula elements and whether the proposed formula appropriately balances ratepayer and shareholder risk, is in the public interest, and will result in just and reasonable rates.

e. PBR Term

NSTAR Gas included an initial term of five years for the PBR Plan, with a provisional five-year extension (Exh. ES-WJA/DPH-1, at 79, 93-95). The initial five-year PBR term would commence on November 1, 2020, and expire on October 31, 2025 (Exh. ES-WJA/DPH-1, at 94). Within the five-year term, there would be four annual PBRM adjustments taking effect November 1, 2021, November 1, 2022, November 1, 2023, and November 1, 2024 (Exh. ES-WJA/DPH-1, at 94). In conjunction with the PBR term, NSTAR Gas proposed a stay-out provision during which the Company commits to file rate schedules to put new base distribution rates into effect no earlier than November 1, 2025 (Exh. ES-WJA/DPH-1, at 94).

The Department has found that a well-designed PBR Plan should be of sufficient duration to give the plan enough time to achieve its goals and to provide utilities with the appropriate economic incentives and certainty to follow through with medium- and long-term strategic business decisions. D.P.U. 96-50 (Phase I) at 320; D.P.U. 94-158, at 66; D.P.U. 94-50, at 272. In addition, the Department has stated that one benefit of incentive regulation is a reduction in regulatory and administrative costs. D.P.U. 18-150, at 53; D.P.U. 17-05, at 402; D.P.U. 96-50 (Phase I) at 320; D.P.U. 94-158, at 64.

Previous PBR plans approved by the Department have had terms of five and ten years. See, e.g., D.P.U. 18-150, at 56 (five years); D.P.U. 17-05, at 404 (five years); D.T.E 05-27, at 399 (ten years); D.T.E. 03-40, at 495-496 (ten years); D.T.E. 01-56, at 10 (ten years); D.P.U. 96-50 (Phase I) at 320 (five years). With the exception of the PBR plan approved in D.P.U. 96-50 (Phase I), the Department has historically found that five-year terms are not long enough for gas distribution companies to achieve the efficiencies and benefits that a PBR plan is expected to provide to shareholders and ratepayers. D.T.E. 03-40, at 495. Accordingly, the Department rejects the Company's proposed five-year term.

The Department finds that a ten-year term will give the plan sufficient time to achieve its goals and to evaluate administrative efficiencies, and will provide the Company with the appropriate economic incentives for cost containment and long-term planning. A ten-year term is consistent with previous Department approved gas distribution company PBR plans and G.L. c. 164. By extending the PBR term, the Company will have a better opportunity to achieve efficiencies crucial to the success of incentive regulation, which should provide benefits to ratepayers and shareholders alike. As discussed in more detail in Section V.B.4.f.ii, after review, the Department will determine whether capital additions through 2024 may be rolled into base distribution rates on November 1, 2025.

Furthermore, a stay-out provision provides an important benefit to ratepayers as it will ensure that there are strong incentives for cost containment under the PBR. D.P.U. 18-150, at 55; D.P.U. 17-05, at 403. Accordingly, the Department adopts a stay-out provision in conjunction with the ten-year term. For the reasons discussed above, the Department finds that the Company's PBR shall operate for a ten-year term starting November 1, 2020.[35] Additionally, the Company shall commit to not file a petition under G.L. c. 164, § 94 that seeks to put increased base distribution rates into effect prior to November 1, 2030.[36] In the event that the Company elects to file a petition for a change in base distribution rates for effect prior to November 1, 2030, the PBRM and all associated factors shall terminate when that case is filed.

f. Rate Base Proposals

i. 2019-2020 Capital Additions

(A) Introduction

NSTAR Gas seeks to roll in its 2019 and 2020 non-GSEP plant additions into rate base. NSTAR Gas does not seek to roll in its 2019 and 2020 non-GSEP plant additions into rate base, however, on the basis that they represent a significant investment that has a

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35 The Company proposed to amortize its new balance of active protected receivables over five years, resulting in an annual amortization expense of $602,516 (Exhs. ES-DPH/ANB-1, at 99; ES-DPH/ANB-2, at Sch. 23). Because the Department adjusted the proposed PBR term to ten years, a corresponding adjustment must be made to the Company's proposed annual amortization of active protected receivables. Accordingly, the Department directs NSTAR Gas to amortize its hardship receivable balance over ten years, resulting in an allowed annual amortization expense of $301,258 (see Department Schedule 3 in Section XVI, below).

36 If the NSTAR Gas ends its PBRM prior to the end of the ten-year term, then, in its next base distribution rate case, the Department will consider the effects in setting the ROE unless the Department denies the base distribution rate adjustment for the 2021 through 2024 investments (see Section V.B.4.f.ii, below).

substantial effect on the Company's rate base. Rather, NSTAR Gas ties its request to include the post-test-year plant additions in rate base to the recent and expected-to-continue increase in capital investment, a decline in new customer revenues, and the long-term effectiveness of the PBRM (Company Brief at 50-53; Company Reply Brief at 31-33). The Attorney General argues that the Company's proposal to include post-test-year plant additions in rate base is inconsistent with Department precedent, and, even if the Department were to allow the PBR Plan, an exception to the post-test-year standard on rate base additions still is not appropriate (Attorney General Brief at 14-17; Attorney General Reply Brief at 4-7). The Department has carefully considered the arguments of the parties and the record supporting their positions. As discussed below, we conclude that there are substantial circumstances present that persuade us to consider the Company's post-test-year plant additions without regard to the size of the additions in relation to rate base.

(B) Increase in Non-GSEP Safety and Reliability Investment

The Company's strategic plan anticipates that capital investment costs will continue to increase through 2023 with budgeted, non-GSEP plant additions in 2023 being nearly double the amount in 2015 (Exhs. WJA/DPH/ANB-1, at 26; DPU-ES 12-20, Att. (a); AG 1-18, Att. (b); AG 5-3). The Company expects to invest between $85 million and $100 million annually in non-GSEP capital over the first five years of the PBR Plan (Exhs. WJA/DPH/ANB-1, at 95; DPU-ES 3-12). The Company states that the increase in capital spending is driven by the response to the Merrimack Valley incident and, specifically, the Company's investments in the following categories: (1) $15.3 million in pressure regulation modernization[37]; (2) \$21.5 million in the low-pressure protection program[38]; (3) \$49.5 million in system resiliency investments; and (4) \$189.7 million in system reliability investments[39] (Exhs. DPU-ES 33-13; DPU-ES 33-14; DPU-ES 33-15; DPU-ES 33-16; AG 5-3; Tr. 6, at 756). The estimated spending on these four project categories for the period 2019 to 2023 totals \$272 million (Exh. AG 5-3).

The Attorney General argues, however, that the Company's capital spending projections are unreliable and lack specific project proposals with budgets and approvals (Attorney General Reply Brief at 6). For example, she asserts that the actual amount of plant placed in service in 2020 is expected to be approximately 30 percent short of the amount budgeted (Attorney General Reply Brief at 6). We disagree. The record demonstrates that the Attorney General's argument is premised on comparing the Company's capital budgeting and strategic planning processes, which are dissimilar.

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37 Pressure regulation modernization improves system awareness and control of the gas distribution system, increasing safety and reliability (Exh. DPU-ES 33-13). Specific projects include emergency shut-down devices, remote monitoring and control devices, and telemetry (Exh. ES-WJA/DPH-1, at 27). The Company did not invest in pressure regulation modernization between 2015 and 2019 (Exh. AG 5-3).

38 Investments into the low-pressure protection program are intended to provide a third level of pressure protection for low-pressure systems, eliminate single incident failures at all low-pressure district regulators, and convert approximately 17 low-pressure district regulators to intermediate pressure (Exh. ES-WJA/DPH-1, at 28). Between 2015 and 2019, the Company did not make investments in the low-pressure protection program (Exh. AG 5-3).

39 System reliability investments include upgrades to gate and regulator stations, projects to maintain pressure during peak conditions, reinforcements for reliability as well as projects for leak and corrosion remediation, service valve replacement, and system telemetry (Exh. ES-WJA/DPH-1, at 29).

NSTAR Gas develops a capital plan annually as a collaborative effort between the engineering and operations departments to identify specific needs in each area (Exh. ES-LML/TCD-1, at 15). An extensive budget review process is then conducted at year-end by senior management in which the portfolio of projects is considered along with multi-year funding for major projects (Exh. ES-LML/TCD-1, at 15). This annual budget process is distinct from the Company's strategic plan, which is developed by the "Planning Group" to review potential capital spending over the upcoming five-year period (Exh. ES-LML/TCD-1, at 13). The strategic plan is approved by senior management and is then used as the basis for annual capital budget plans (Exh. ES-LML/TCD-1, at 13). While the strategic plan includes capital expenditures and operating cost projections, the focus is the long-term capital investment needs for each functional area (Exh. DPU-ES 11-5). The Department finds that, by its nature, the variance between actual spending and the five-year strategic plan will be inherently greater than the variance between actual spending and the annual capital budget plan due to the greater likelihood of unforeseen contingencies, over a longer time period.

The Company's 2019 capital budget was created in December 2018 based on the 2018 strategic plan (Exh. ES-LML/TCD-1, at 13-14). The 2019 strategic plan, however, is dated April 15, 2019, seven months after the Merrimack Valley incident (Exh. DPU-ES 33-12, Att. (b)). There are significant increases in the budgeted amounts of the 2018 and 2019 strategic plans specific to system resiliency, system reinforcement, gate and regulator stations, and low-pressure protection system and reliability projects (Exh. DPU-ES 33-12, Atts.). It is reasonable to expect that, given the Merrimack Valley incident's profound impact on the industry, NSTAR Gas's strategic planning, post-Merrimack Valley incident, would contain significant budget increases as the Company plans its future spending in response to lessons learned from the Merrimack Valley incident (Exhs. ES-WJA/DPH-1, at 11, 34, 37; DPU-ES 23-15 & Atts.; Tr. 6, at 806). And, while the actual 2019 investment did not rise to the level expected in the strategic plan (Exh. DPU-ES 33-21), we are persuaded by the record evidence that the Company will remain committed to making the necessary investments in order to ensure system safety and reliability in the wake of the Merrimack Valley incident (Exhs. ES-WJA/DPH-1, at 11, 34, 37; DPU-ES 23-15 & Atts.; Tr. 6, at 847-848).

Accordingly, the Department finds that the heightened level of investment discussed above will result in significant carrying costs to the Company over the ten-year term of the PBR plan (Exhs. ES-WJA/DPH-1, at 25; DPU-ES 3-9; DPU-ES 3-10; DPU-ES 7-3; DPU-ES 12-14; AG 9-24; RR-DPU-16, Att.). The ten-year PBR term and stay-out provision approved above would preclude the Company from seeking a base distribution rate increase to begin recovering the costs of those investments; therefore, the Department finds that it is appropriate to consider the significant carrying costs in light of the Company's proposed capital additions.

(C) Offsets to Capital Carrying Costs

The Attorney General argues that a significant portion of the Company's non-GSEP projects are revenue producing, and, therefore, under revenue decoupling, the revenues are retained by the Company and will partially offset the carrying costs of non-revenue producing plant investments (Attorney General Brief at 17). We disagree. During the proceeding, the Department solicited testimony and detailed calculations from NSTAR Gas demonstrating how projected PBR revenues, projected new customer revenues, and depreciation accounting would offset the capital carrying costs discussed above (Exhs. DPU-ES 12-10 & Atts.; DPU-ES 28-1 & Atts.; DPU-ES 28-2 & Atts.; Tr. 2, at 283-326; Tr. 3, at 380-390; Tr. 6, at 778-793; RR-DPU-16). The Company estimates that, under the PBR Plan, annual increases in revenue should be approximately $8 million (Exh. ES-WJA/DPH-1, at 95; Tr. 3, at 381). Further, incremental revenues from customer growth range from $1.6 million to $1.9 million[40] each year, accounting for customers leaving the system and assuming the level of revenues from new customer additions stays flat (Exh. DPU-ES-28-1; Tr. 2, at 298; Tr. 6 at 812; RR-DPU-3). Based on conservative estimates of PBR revenues, revenues from customer growth and capital additions, and accounting for depreciation, the Company forecasts revenue requirement deficits ranging from $12.6 million to $26.8 million each year for the first five years of the PBR term (RR-DPU-16, Att., at 1). Therefore, we find that

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40 Forecasted new customer revenue is derived at the rate level by multiplying the latest approved tariffs from July 1, 2018 by the Company's unit forecast of distribution (sales), customer count and demand. Gas sales and customer counts are forecasted econometrically utilizing four years of historical data and incorporate changes in energy prices and economic conditions. Demand is forecasted by analyzing the trends over the most recent three-year period. The line item entitled "Expected Decoupled Customer Reduction" reflects the fact that the decoupled revenues are not "fixed" and the decoupled customer population is expected to decline slightly each year resulting in lower decoupled revenues (RR-DPU-3).

there is substantial record evidence to demonstrate that the projected PBRM revenues, new customer revenues, and adjustment for depreciation are most likely insufficient compared with the revenue requirement associated with NSTAR Gas's increased capital spending requirements to prevent the Company from the necessity of filing for rate relief prior to the end of the PBR term.

(D) Conclusion

Above, the Department approved a ten-year PBR term and stay-out provision in order to maximize the benefits achieved for NSTAR Gas's customers and shareholders under the PBR Plan. NSTAR Gas has demonstrated its commitment to a significant increase in its non-GSEP investments to improve the safety and reliability of its distribution system, representing about 50 percent of its overall capital spending, and the Department has found that the PBRM affords the Company needed flexibility to address a changing and uncertain operating environment. In light of these circumstances, the Department finds that NSTAR Gas has made a convincing showing that the proposed roll-in of 2019 and 2020 non-GSEP capital investments is necessary to cover the expected increase in costs associated with necessary capital investments, particularly those undertaken in response to the Merrimack Valley incident, and to ensure the potential benefits of the PBRM to customers are realized (Exhs. ES-WJA/DPH-1, at 26, 95-96; DPU-ES 12-20, Att. (a); DPU-ES 33-12; DPU-ES 33-13; DPU-ES 33-14; DPU-ES 33-15; DPU-ES 33-16; AG 1-18, Att. (b); AG 5-3; Tr. 3, at 381; Tr. 6, at 807; RR-DPU-16). In making these findings, however, we seek to strike a balance between establishing an appropriate foundation upon which PBR revenues can grow and support the Company's ambitious strategic plan spending and mitigating bill impacts on ratepayers by maintaining an appropriate level of annual rate increases during the PBR term.

Thus, in base distribution rates effective November 1, 2020, the Company's rate base will be determined by the test-year net plant, as determined above, and consistent with traditional cost of service ratemaking.[41] In the Company's initial PBR filing, effective November 1, 2021, rate base will be updated to incorporate the 2019 non-GSEP plant additions along with the associated accumulated depreciation. The Company shall adjust the base distribution rates for depreciation expense, return on rate base, associated federal and state income taxes, property taxes, and revenues for all existing non-GSEP assets ending December 31, 2019. During the instant proceeding, the Company provided project documentation to support its proposed 2019 capital additions (Exhs. ES-LML/TCD-1 (Supp.) at 3; ES-LML/TCD-3; ES-LML/TCD-13). The parties were afforded an extended opportunity to conduct discovery on the project documentation and to cross-examine the Company's witnesses during the evidentiary phase of the proceedings (see, e.g., Exhs. AG 36-1; AG 40-1 through AG 40-9; AG 46-1 through AG 46-14; Tr. 6, at 861-889).

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41 As part of NSTAR Gas's proposal to update rate base for actual 2019 plant balances, the Company also proposed a $3,150,999 decrease to operating revenues (Exh.ES-DPH/ANB-1, at 11-12; ES-DPH/ANB-2, Sch. 6; ES-DPH/ANB-2 (Rev.) at Summary of Cost of Service Changes, Sch. 1, at 1, 9; Sch. 6). Consistent with our decision to determine rate base using the test-year-end plant balance in base distribution rates effective November 1, 2020, the Company's operating revenues will be based on the test-year-end amount. This adjustment is shown on Department Schedules 1 and 9 in Section XVI, below.

Therefore, the Department finds no due process concerns associated with the review of the Company's 2019 capital additions.

The Company may seek to update its rate base to incorporate the 2020 non-GSEP plant additions along with associated accumulated depreciation as part of its second annual PBRM filing effective November 1, 2022. The Company shall file no later than May 1, 2022, all relevant project documentation and supporting testimony to demonstrate that the costs associated with the 2020 investments were prudently incurred and that the plant is used and useful in service to customers. The Company shall adjust the base distribution rates for depreciation expense, return on rate base, associated federal and state income taxes, and property taxes for all existing non-GSEP assets ending December 31, 2020. The Department will establish an appropriate procedural schedule to provide interested parties an opportunity to review the project documentation and supporting testimony.

In light of our findings above, we need not address whether the Company's proposal is consistent with the Department's decision in D.P.U. 18-150, or any of the Company's other discrete arguments. These findings above provide a sufficient basis upon which to allow the Company to incorporate post-test-year plant additions in rate base. We stress, however, 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.

ii. 2021-2024 Capital Additions

NSTAR Gas conditioned its proposed five-year PBR term extension in part on allowing the revenue requirement associated with the capital additions completed through December 31, 2024 into base rates in year five of the PBR Plan term (i.e., for rates effective on November 1, 2025) (Exh. ES-WJA/DPH-1, at 94-95). The Company argued that the expected cost of the investments during the first five years of the PBR would not allow it to continue the PBR for another five years without incorporating these capital costs (Company Brief at 79). TEC, on the other hand, argues that the Department has a responsibility to ratepayers to ensure that capital additions are prudent, and that any future approval of capital costs in base distribution rates should only occur through a base distribution rate proceeding (TEC Brief at 7).

The Department finds that too many uncertainties exist at this time to determine whether the revenue requirement associated with the 2021 through 2024 investments should be allowed to be included in rate base in year five of the PBR term for rates effective on November 1, 2025. As such, we find that we would consider allowing these investments into base rates in year five of the PBR term on November 1, 2025, if the Company can demonstrate in its 2024 annual PBR filing (i.e., filed September 15, 2024) that the Company has met the following conditions: (1) achieved all of its scorecard metrics within the first four years of the PBR term with reasonable variance shown to be outside the Company's control; (2) invested in capital in accordance with its five-year capital plan (Exhs. DPU-ES 12-10 & Att. (b), AG-1-18 & Att. (b); AG-5-3); and (3) filed with the

Department its most recent five-year capital spending plan.[42, 43] Additionally, the Department directs the Company to file with its September 15, 2023 annual PBR filing a progress report on its five-year capital plan reconciled with its capital budget forecast.[44] If the Department allows the base distribution rate adjustment adjustment for the 2021 through 2024 investments, then the Company shall maintain its commitment to forgo a base distribution rate proceeding and continue with its PBRM through November 1, 2030.

g. PBR Formula Elements

i. X Factor

(A) Introduction

In the context of a revenue cap formula that uses an economy-wide measure of inflation, a productivity offset (or X factor) consists of the (1) differential in expected productivity growth between the natural gas local distribution industry and the overall economy and (2) the differential in expected input price growth between the overall economy

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42 If the Department allows these investments to be included in base distribution rates on November 1, 2025, subject to a prudence review, then NSTAR Gas shall file with the Department capital project documentation for projects completed January 1, 2021 through December 31, 2024 on or before April 1, 2025 for Department review (Exh. ES-WJA/DPH-1, at 99).

43 The Department expects the Company to demonstrate capital investment in accordance with the total five-year capital plan as provided in Exhibit DPU-ES 12-10 & Att. (b), as well as at the program level (i.e., Exhibit AG-5-3), and at the business unit level (i.e., Exhibit AG-1-18 & Att. (b)).

44 The Department expects the Company to provide a progress report with the total five-year capital plan as provided in Exhibit DPU-ES 12-10 & Att. (b), as well as at the program level (i.e., Exhibit AG-5-3), and at the business unit level (i.e., Exhibit AG-1-18 & Att. (b)).

and the LDC industry (Exhs. ES-JF/MF-1, at 45; ES-JF/MF-2, at 46). In combination with the inflation factor, the X factor is designed to represent the expected unit cost performance of an average performing company in the industry (Exh. ES-WJA/DPH-1, at 81). As described above, NSTAR Gas conducted multiple TFP analyses and ultimately proposed an X factor in the instant case equal to -1.18 percent[45] (Company Brief at 26). The Attorney General also conducted multiple TFP analyses that produced a range of X factor results from -1.07 percent to -0.69 percent (Exh. AG-MNL-1 at 15). As noted above, the Attorney General proposed an X factor of -0.69 percent (Attorney General Brief at 126). The X factors produced by the Attorney General's TFP analysis differ from the Company's TFP study in several ways, which the Department reviews in the sections below. In the subsequent sections, the Department details its decision to accept the Company's proposed X factor of -1.18 percent to be used in the PBRM.

(B) Treatment of CS&I Expenses

One of the inputs into the Company's TFP and benchmarking studies is total OM&A expenses (Exhs. ES-JF/MF-2, at 27; ES-JF/MF-3, at 12). The Company included categories of costs, as reported in FERC Form 2 and LDC State Filings, associated with physical productivity of distribution for LDCs, including expenses associated with storage, distribution customer service account, sales, and administrative and general expenses, including labor

45 The Company initially proposed an X factor of -1.30 percent, but during the proceeding updated the proposal to -1.18 percent based on a correction to the Company's TFP study (Exhs. ES-JF/MF-1, at 29-31; ES-JF/MF-2, at 47; RR-DPU-21, at 1-2).

(Exhs. ES-JF/MF-2, at 27-28; ES-JF/MF-3, at 12). For the same reason, the Company excluded costs in the categories of transmission and fuel procurement (Exh. ES-JF/MF-2, at 27). According to the Company, OM&A costs included CS&I expenses for all sampled LDCs (Exh. AG 9-10).[46]

The Attorney General argues that it is inappropriate to include CS&I expenses in the TFP and benchmarking cost calculations. The Attorney General specifies that CS&I expenses oftentimes include DSM expenses and that DSM expenses can account for a large portion of total CS&I expense (Exh. AG-MNL-Surrebuttal, at 3). The Attorney General explains that the Company excludes DSM expenses of NSTAR Gas and other Massachusetts LDCs because they are not reported in CS&I expenses, but includes DSM expenses for other LDCs, resulting in a bias in favor of NSTAR Gas (Exhs. AG-MNL-Surrebuttal, at 4; AG 9-10). Conversely, the Company holds that the Attorney General inaccurately characterizes the type of costs included in the CS&I category (Exh. ES-JF/MR-Rebuttal-1, at 25-27). The Company argues that excluding the entire CS&I expense category excludes and underestimates other expenses, and it is therefore incorrect to exclude CS&I expenses for the purpose of eliminating DSM (Exh. ES-JF/MR-Rebuttal-1, at 28). The record in the instant proceeding demonstrates that DSM expenses have been declining over time while CS&I expenses have been increasing, which would indicate that CS&I trends have not been

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46 CS&I expenses are defined as "the cost of labor, materials used, and expenses incurred in providing instructions or assistance to customers, the object of which is to encourage safe, efficient, and economical use of the associated utility company's service." (Exh. AG 9-10)

driven by DSM expenses, but rather by other legitimate costs that are relevant to the determination of TFP trends (Exh. AG 44-6; Tr. 11, at 1452-1453; RR-DPU-21, at 1). Therefore, the Department finds that the exclusion of CS&I expenses is not appropriate and would likely ignore important costs that affect LDC productivity trends.

(C) Peer Group Selection (National vs. Regional)

The Company calculated TFP and corresponding X factors using two different samples for its productivity study: (1) a sample of 83 U.S. LDCs intended to represent the overall nationwide LDC industry and (2) a sample of 29 LDCs intended to represent the LDC industry in the Northeast Region (Exhs. ES-JF/MF-1, at 21; ES-JF/MF-2, at 5-7). The TFP study for the national sample results in an X factor of -0.76 percent, and the TFP study for the Northeast sample results in an X factor of -1.18 percent (RR-DPU-21, at 2). The Company proposed that the X factor corresponding to the Northeast peer group sample of -1.18 percent be used for the PBRM, stating that this X factor is the most appropriate due namely to three differences between the Northeast Region and the rest of the United States that may impact productivity growth in the LDC sector: (1) lack of economies of scale (i.e., smaller pipeline systems in the Northeast); (2) technology (i.e., a greater proportion of older, cast or wrought iron mains in the Northeast); and (3) output growth (i.e., a slower rate of growth in number of customers in the Northeast) (Exhs. ES-JF/MF-1, at 9-10; 29-31; ES-JF/MF-2, at 42-43; ES-JF/MF-Rebuttal-1, at 49-52; RR-DPU-21, at 2). For these reasons, the Company asserts that Northeast Region LDCs are closer peers to NSTAR Gas than the National LDC sample (Exh. ES-JF/MF-Rebuttal-1, at 49).

Alternatively, the Attorney General argues that it is more appropriate to use the national peer group to calculate the X factor for two reasons (Exhs. AG-MNL-1, at 9-10, 15; AG-MNL-2, at 41, 50). First, the Attorney General explains that NSTAR Gas does not have the same slower customer growth that is exhibited in the Northeast Region, which gives the Company more opportunity to realize economies of scale (Exhs. AG-MNL-1, at 9-10; AG-MNL-2, at 41, 50). Second, the Attorney General points out that, since the Company proposes to track GSEP costs outside of the PBRM, the impact of having a relatively higher proportion of older, cast iron mains would be accounted for outside of the X factor (Exhs. AG-MNL-1, at 9-10; AG-MNL-2, at 41, 50).

The Department recognizes that TFP growth differs between the national and regional group for a variety of reasons. Differences in economies of scale, technology, input and output growth, population density, system size, and system composition influence trends in TFP over time, and the Company has demonstrated that the LDCs in the Northeast have characteristics that differ from LDCs in the rest of the United States, such that the regional peer group is more appropriate for the purpose of setting an X factor (Exhs. ES-JF/MF-1, at 28-31; ES-JF/MF-3 (Rev.) at 21; ES-JF/MF-Rebuttal-1, at 50-52; Tr. 7, at 922-925, 930-931). With respect to inclusion of GSEP costs in the TFP study, both parties acknowledge that there is no practical or straightforward way to exclude GSEP costs from the X factor calculation due to data limitations (Exh. ES-JF/MF-Rebuttal-1, at 60; Tr. 11, at 1516-1518). While the inclusion of GSEP costs may have some effect on TFP growth, NSTAR Gas determined that the impact would not be significant or material (Exh. DPU-ES 32-1, at 4).

In recently approved PBR proposals for electric distribution companies, the Department has accepted the use of national peer groups for purposes of setting an X factor. D.P.U. 18-150, at 58, 60; D.P.U. 17-05, at 383-384. In those proceedings, one of the concerns regarding the regional peer group was the potential for sample endogeneity, but here such concerns are non-existent. D.P.U. 17-05, at 384, 386. Additionally, while electric distribution companies have relied on national peer groups, the Department has historically found that regional peer groups are more appropriate for setting X factors for LDCs. D.T.E. 05-27, at 363; D.T.E. 03-40, at 475; D.P.U. 96-50 (Phase I), at 275-276. The evidence provided in the instant proceeding is consistent with the Department's past findings. We find that the use of a regional peer group is consistent with Department precedent and that conditions in the Northeast are unique enough to determine that the Northeast region LDCs are closer peers to NSTAR Gas than the national LDC sample. Moreover, the regional peer group accounted for 94 percent of gas customers in the Northeast region and 81 percent of the total volume of gas sales as of 2017, which the Department finds is sufficiently robust, providing a reliable basis to establish TFP (Exh. ES-JF/MF-1, at 21). Accordingly, the Department accepts the Company's reliance on the regional peer group for establishing an appropriate X factor.

(D) Use of Allegedly Flawed Data

The Attorney General argues that the Company's TFP study uses flawed data, as it includes companies whose data were compromised by acquisitions, mergers, and divestitures (Attorney General Brief at 123). NSTAR Gas insists the Attorney General's argument should be disregarded, as her exclusions of data were arbitrary and improperly informed (Company Brief at 59). The Department is not persuaded that the Attorney General's concerns are warranted, as it is unclear how the inclusion of companies that underwent acquisitions, mergers, and divestitures is inherently flawed. The Attorney General's assertions that the TFP study relied on flawed data is not sufficiently supported, and, therefore, the Department agrees with the Company's contention that such exclusions are arbitrary.

(E) TFP Study Benchmark Year

In order to calculate the quantity of capital stock over time, an input into the calculation of TFP, the Company first had to choose an initial "benchmark year" as a starting point of the capital stock calculation (Exhs. ES-JF/MF-2, at 34; AG-MNL-3, at 31). The Company describes that the capital quantity in the benchmark year is calculated from the gross book value of all capital assets for each company in the sample, a value which is comprised of assets of many different vintages (Exh. ES-JF/MF-2, at 34).[47] For this reason, the measure of capital stock is sensitive to the age of the different components captured in the

[47] Capital stock in the benchmark year is calculated by dividing the estimated gross book value of a company's gas distribution asset base in 1998 by a 51-year average of an inflation index for 1998 and the previous 51 years (Exh. ES-JF/MF-2, at 31, 34-35; DPU-ES 12-22 & Att.). Fifty-one years is the average service life calculated for the studies (Exh. ES-JF/MF-2, at 31).

gross book value (Exh. ES-JF/MF-2, at 34). The Company used 1998 as a benchmark year, explaining that while a year well before the study period begins in 2003 is preferable for accuracy, this must be balanced by a consideration of data availability (Exh. ES-JF/MF-2, at 34).

The Attorney General is concerned that 1998 is too close in time to the study period, reducing the accuracy of the benchmarking and X factor study results (Exhs. AG-MNL-1, at 9, 18; AG-MNL-3, at 40, 43). Both the Company and the Attorney General agree that the calculation is likely to be more accurate if the benchmark year is earlier in time and that the choice of a benchmark year will depend on data availability (Exhs. ES-JF/MF-2, at 34; AG-MNL-3, at 31, 43; AG-MNL-Surrebuttal at 5). The Company contends that 1998 is an appropriate year given the availability of data, as estimating the benchmark capital stock in an earlier year would have limited the number of peer companies in the sample due to data availability (Exh. ES-JF/MF-Rebuttal-1, at 19-20).[48] Further, the Company argues that, counter to the Attorney General's assertion, the use of a later benchmarking year does not universally lead to underestimation of the TFP trend because deviations in real capital stock can be in either direction, depending on each firm's investment cycle (Exh. ES-JF/MF-Rebuttal-1, at 20-21). The Company demonstrates, using NSTAR Gas as

48 If the Company were to use 1994 instead, the sample would lose representation for 15 to 20 percent of total customers served in 2017, depending on the sample (national or regional, respectively) (Exh. ES-JF/MF-Rebuttal-1, at 19-20). This would result in around 80 percent representation for the regional sample, and 55 percent for the national sample (Exh. ES-JF/MF-2, at 5, 7).

an example, that using 1984 as a benchmark year, in fact, leads to a lower estimate of capital stock and a negligible impact on TFP growth rate (i.e., that it was not understated using the later benchmark year) (Exh. ES-JF/MF-Rebuttal-1, at 21-24). The Department recognizes that an earlier benchmark year provides more accurate results in some instances (Exh. ES-JF/MF-1, at 22). Nonetheless, the Department also acknowledges that sample size is an important consideration for the purposes of conducting a robust study and there are limitations to the financial and operating data available for LDCs (Exh. ES-JF/MF-1, at 22). Accordingly, the Department is unpersuaded by the record evidence that the use of an earlier benchmark year is appropriate in this case.

(F) Conclusion

In the sections above, the Department has reviewed the Company's proposed TFP study, which generates an X factor of -1.18 percent that was used in the benchmarking study to measure the NSTAR Gas's cost performance. The Department recognizes that all studies rely on various assumptions, as well as matters of judgement based on expertise (Exh. ES-JF/MF-Rebuttal-1, at 44; Tr. 11, at 1527-1528). While the Attorney General raises concerns about certain assumptions and parameters used in the Company's TFP study, the Department finds that NSTAR Gas's study is reasonable. Accordingly, the Department approves the Company's proposed X factor of -1.18 percent based on a regional sample.

ii. Consumer Dividend

The consumer dividend is intended to reflect expected future gains in productivity because of the move from cost of service regulation to incentive regulation. D.P.U. 96-50 (Phase I) at 165-166, 280. As a deduction to the PBR adjustment, the consumer dividend is designed to allow ratepayers to share in these aforementioned gains (Exh. ES-JF/MF-1, at 18). NSTAR Gas proposes not to apply a consumer dividend as part of the PBRM (Exhs. ES-WJA/DPH-1, at 84; AG 37-1 Att. (b), at 45).

The Company conducted a total cost benchmarking study and determines that the results of the study indicate that NSTAR Gas is already relatively efficient, is an above-average performer, and therefore there is no need to include a stretch factor in the revenue cap per customer proposal (Exhs. AG- 7-1, Att. (b) at 45; DPU-ES 12-8). Further, the Company claims, that even absent a consumer dividend, the I-X formula in the PBRM incentivizes the Company to maintain productivity over time that is in line with the industry trend, otherwise, it will not realize its allowed ROE (Exh. DPU-ES 12-8). The Company asserts that, based on its already high level of efficiency, its performance goal during the PBR term should be to maintain its efficiency over a period where it may experience increasing costs, as opposed to eradicating existing inefficiencies which is what a consumer dividend is designed to incentivize (Exhs. DPU-ES 3-4; DPU-ES 22-15).

The Attorney General argues that there are several methodological concerns with how the Company conducted the benchmarking study and she conducted a revised benchmarking analysis to account for some of these concerns. The Attorney General concludes that, contrary to the Company's assertion, NSTAR Gas is an average cost performer (Exh. AG-MNL-3, at 53). The Attorney General also argues that the Company's proposed consumer dividend of zero is not supported by the benchmarking results (Exh. AG-MNL-1, at 21-22).

As with the Attorney General's critiques of the Company's TFP study, the Department finds that the critiques associated with the Company's benchmarking study are similarly unfounded. The Department also acknowledges that experts rely on various assumptions that are often based in professional judgment and do not necessarily render a study faulty.

The Department has previously found that a consumer dividend represents an explicit, tangible ratepayer benefit. D.P.U. 18-150, at 60-61; D.P.U. 17-05, at 395. The Department is concerned that without a consumer dividend, ratepayer benefits will be realized only at the end of the PBR term when rates are reset, rather than throughout its operation. Therefore, the Department is not persuaded that a consumer dividend of zero is appropriate.

While NSTAR Gas proposes no consumer dividend, the Company acknowledges that in the context of a PBR formula set on the basis of a regional peer group, it could operate with a consumer dividend between 10 and 15 basis points (Exh. DPU-ES 22-15, at 1). Moreover, on reply brief the Company notes that its cost performance would align with a stretch factor of 0.15 percent under the criteria established for assigning stretch factors in Ontario (Company Reply Brief at 21-22). As such, the Department finds that the record supports that a consumer dividend of 0.15 percent is necessary to provide an immediate ratepayer benefit, consistent with Department precedent. Accordingly, the Department directs the Company to incorporate a consumer dividend of 0.15 percent in its PBR formula.

iii. Earnings Sharing Mechanism

The Department has found that ESMs may be integral components of incentive regulation plans. D.P.U. 94-50, at 197 n.116. Specifically, the Department has found that ESMs provide an important backstop to the uncertainty associated with setting the productivity factor. D.P.U. 18-150, at D.P.U. 17-05, at 400; D.P.U. 96-50 (Phase I) at 325; D.P.U. 94-50, at 197.

The Company proposes to implement a symmetrical ESM with a deadband of 100 basis points (Exh. WJA/DPH-1, at 91). Under the Company's proposal, earnings or losses would be shared with ratepayers and shareholders on a 75/25 percent basis (i.e., 75 percent to ratepayers and 25 percent to shareholders) when the calculated distribution ROE either exceeds or falls short of the ROE authorized in this proceeding by 100 basis points (Exh. WJA/DPH-1, at 91).

The Attorney General, as well as TEC, argue that a symmetrical ESM punishes ratepayers and acts primarily to protect the Company's shareholders. Both intervenors argue that the Department should approve an asymmetrical ESM, with sharing only occurring in the instance of earnings above the proposed deadband (Attorney General Brief at 134; TEC Brief at 8).

An ESM offers an important protection for ratepayers in the event that expenses increase at a rate much lower than the revenue increases generated by the PBR. D.P.U. 18-150, at 70; D.P.U. 17-05, at 400; D.P.U. 10-70, at 8 n.3; D.T.E. 05-27, at 404-405. For this reason, the Department finds that there is a significant benefit to implementing an ESM as part of the PBRM adopted in this case. As discussed below, the Department finds that certain modifications to the Company's proposed earnings sharing mechanism are necessary to appropriately balance the risks to shareholders and ratepayers under the PBR.

Regarding a symmetrical or asymmetrical deadband, the Department finds that an asymmetrical deadband, as proposed by the Attorney General and TEC, appropriately protects ratepayers, is consistent with recent Department precedent, and further increases the Company's incentives to pursue savings, as a greater share of under-earnings will be borne by the Company. D.P.U. 18-150, at 71-72; D.P.U. 17-05 at 401. In contrast, a symmetrical deadband inappropriately shifts losses to ratepayers.

As noted above, the Company proposed to adopt a deadband of 100 basis points (Exh. WJA/DPH-1, at 91). The Department has recently, and historically, approved ESMs with deadbands of 200 basis points or greater. D.P.U. 18-150, at 71-72; D.P.U. 17-05, at 401; D.T.E. 05-27, at 405; D.T.E. 03-40, at 500; D.P.U. 96-50 (Phase I) at 326. NSTAR Gas acknowledges that the 100-basis point deadband is narrower than would typically apply in an ESM but argues that it is appropriate due to the future uncertainty plaguing the gas distribution industry (Exh. ES-WJA/DPH-1, at 91). Here, the Department is not persuaded that a 100-basis point deadband below the authorized ROE is appropriate.

The Department has concerns regarding a narrow deadband because increased administrative efficiency and reduced administrative costs are both considered benefits of incentive regulation. D.P.U. 96-50 (Phase I) at 320; D.P.U. 94-158, at 64. When the

Department inquired as to how the Company would have fared with its proposed ESM if it had been in place during the period of 2008 through 2018, the Company demonstrated that the ESM would have been triggered for an ROE below the authorized level in 2008, 2012, and 2016 under an ESM with a 100-basis point deadband, but not at all if it had a deadband of 200-basis points (Exhs. DPU-ES 3-2 & Att. (a); DPU-ES 3-3 & Att.). Further, the Company testified that with a 100-basis point deadband, any modifications to the PBR Plan would likely trigger the ESM for earnings below the authorized ROE as soon as the first year of the PBR term (Tr. 3, at 388-390; Tr. 6, at 712; RR-DPU-15). While the Company argues that this circumstance would indicate that the PBRM is not operating as intended, the Department finds that this result is more indicative that the deadband below the ROE is too narrow and, therefore, that the ESM is too sensitive to downside risk (Company Reply Brief at 41).

The Department finds that an asymmetrical deadband of 100 basis points above and 150 basis points below the authorized ROE is appropriately sensitive to variations in ROE, administratively efficient, consistent with Department precedent, and will provide the Company with a strong incentive to pursue savings. To appropriately balance shareholder and ratepayer risk under the PBRM as designed, the Department finds that the benefits of any earnings above the deadband must inure largely to ratepayers. Accordingly, we find that a mechanism that shares earnings with ratepayers and shareholders on a 75/25 percent basis (i.e., 75 percent to ratepayers and 25 percent to shareholders) for earnings more than 100 basis points above the authorized ROE and losses with ratepayers and shareholders on a

50/50 percent basis (i.e., 50 percent to ratepayers and 50 percent to shareholders) for losses between 150 and 200 basis points below the authorized ROE, and on a 75/25 percent basis (i.e., 75 percent to ratepayers and 25 percent to shareholders) for losses more than 200 basis points below the authorized ROE is appropriate in this case. These ratios will provide NSTAR Gas an adequate incentive to pursue savings while protecting ratepayers from any unforeseen financial windfall or underearning for the Company.

In conclusion, the Department finds that the Company's PBRM shall include an asymmetrical ESM that sets a deadband of 100 basis points above and 150 basis points below the Company's authorized ROE. If NSTAR Gas's earned distribution ROE falls within the deadband, there will be no sharing. If the Company's earned distribution ROE exceeds the authorized ROE by more than 100 basis points, the earnings above the deadband will be shared 75 percent with ratepayers and 25 percent with shareholders. If the Company's earned distribution ROE is between 150 and 200 basis points below the authorized ROE, the shortfall below the deadband will be shared 50 percent with ratepayers and 50 percent with shareholders, and if the Company's earned distribution ROE is more than 200 basis points below the authorized ROE, the shortfall below the 150 basis point deadband[49] will be shared 75 percent to ratepayers and 25 percent to shareholders.

[49] The Department will fully review the Company's ESM filing and may make a financial adjustment if it determines that the Company underearned as a result of inappropriate spending or accounting to trigger an ESM. The ESM is not designed to create a perverse incentive but rather to balance risk under a multi-year PBR plan.

iv. Exogenous Cost Factor

In D.P.U. 94-158, at 62, the Department recognized that there may be exogenous costs, both positive and negative, that are beyond the control of a company and, because the company is subject to a stay-out provision, these costs may be appropriate to recover (or return) through the PBRM. The Department has defined exogenous costs as positive or negative cost changes that are beyond a company's control and are not reflected in the GDP-PI. D.P.U. 94-50, at 172-173. These include incremental costs resulting from: (1) changes in tax laws that uniquely affect the relevant industry; (2) accounting changes unique to the relevant industry; and (3) regulatory, judicial, or legislative changes uniquely affecting the industry. D.P.U. 96-50 (Phase I) at 291; D.P.U. 94-50, at 173. The Department has cautioned against expansion of these categories to a broader range. D.P.U. 96-50 (Phase I) at 290-291; D.P.U. 94-158, at 61-62.

NSTAR Gas proposes to adopt a two-part exogenous cost mechanism (Exh. ES-WJA/DPH-1, at 85-86). The first part is consistent with the definition adopted by the Department in D.P.U. 94-50 (Exh. ES-WJA/DPH-1, at 85-86). Accordingly, the Department finds that the Company's proposed definition of exogenous costs in this instance is appropriate.

The second part is a more targeted definition specific to exogenous events arising due to pipeline safety requirements imposed after November 8, 2019, with demonstrated cost impacts after the inception of the PBRM on November 1, 2020 (Exh. ES-WJA/DPH-1, at 85-86). The Company contends that this additional definition is necessary in order to manage some of the uncertainty the Company expects to encounter over the term of the PBR Plan (Exh. DPU-ES 12-4). While some pipeline safety requirements may arise from regulatory, judicial, or legislative changes and would be captured under the traditional mechanism, the proposed secondary definition is designed to also capture exogenous events that arise from other recommendations or directives that lead to costly institutional changes requiring the Company to modify its operating practices and protocols (Exh. DPU-ES 12-4). The Department finds that future uncertainty in the gas distribution industry, particularly with respect to changes in requirements stemming from the Merrimack Valley incident, warrant a consideration for additional exogenous costs that may arise above and beyond those experienced in the past. Therefore, the Department accepts the Company's proposed two-part definition of the exogenous cost factor.

To avoid a costly regulatory process over minimal dollars, the Department has found that exogenous cost recovery must be subject to a significance threshold that is noncumulative (i.e., exogenous costs cannot be lumped together into a single total for purposes of determining whether the threshold has been met). D.T.E. 01-56, at 22-23; Boston Edison Company, D.T.E. 99-19, at 26 (1999); D.P.U. 96-50 (Phase I) at 292-293; D.P.U. 94-50, at 173. The significance threshold is determined based on a percentage of the company's total operating revenues, taking into account the effects that inflation will have on the threshold in the later years of the PBR Term. D.T.E. 01-56, at 11-14; Eastern Enterprises/Colonial Gas Company, D.P.U. 98-128, at 57 (1999).

NSTAR Gas has proposed an exogenous cost significance threshold of $700,000 for the first compliance year, subject to annual adjustments thereafter based on changes in GDP-PI (Exhs. WJA/DPH-1, at 86-87; DPU-ES 12-2). The Company proposed two different treatments of the threshold for the two proposed parts of the definition of an exogenous cost: (1) the significance threshold for the first part, the traditional exogenous cost factor, would include O&M cost changes in a single year, and (2) the significance threshold for the second part, specific to pipeline safety requirements, would allow for both capital and O&M cost changes, applied separately to O&M and to the revenue requirement of capital costs (Exhs. WJA/DPH-1, at 87; DPU-ES 12-5). Although the Department must consider the facts and circumstances of each case, the Department has previously found that an exogenous cost significance threshold was reasonable where it was equal to a multiple of 0.001253 times a company's total operating revenues. D.P.U. 18-150, at 66-67; D.P.U. 17-05, at 397; D.T.E. 03-40, at 491; D.T.E. 01-56, at 22-26; D.P.U. 98-128, at 53-56; D.P.U. 96-50 (Phase I) at 293.

NSTAR Gas's total test year operating revenues were $499,895,237 (Exh. DPU-ES 12-2). As discussed above, the Department allowed the Company to roll-in prudently incurred 2019 and 2020 non-GSEP capital additions during the PBR term. Due to this we do not find it appropriate to incorporate a second method to collect capital during the PBR plan. Therefore, the Department will only allow the Company to file for exogenous costs on O&M cost changes and not for adjustments to the revenue requirement of capital costs. Consistent with our precedent and the facts of this case, the Department finds that

$700,000 is a reasonable exogenous cost significance threshold for NSTAR Gas, which has total operating revenues of $499,895,237 and is implementing a multi-year PBR Plan of the overall design approved herein.[50]

In addition, the Company has proposed that the exogenous cost significance threshold be subject to annual adjustments based on changes in GDP-PI as measured by the U.S. Department of Commerce (Exh. ES-WJA/DPH-1, at 82, 87).[51] The Department is satisfied that this proposal appropriately considers the effects that inflation will have on the threshold in the later years of the PBR term. D.P.U. 18-150, at 67; D.P.U. 17-05, at 398; D.T.E. 01-56, at 11-14; D.P.U. 98-128, at 57. Accordingly, we set the Company's threshold for exogenous cost recovery at $700,000 for each individual event in calendar year 2020, subject to annual adjustments thereafter based on changes in GDP-PI as used in the PBRM. Based on the foregoing analysis, the Department approves the Company's proposed exogenous cost factor with modifications as a component of the PBRM.

Exogenous cost recovery requires that a company provide supporting documentation and rationale to the Department for a determination as to the appropriateness of the proposed exogenous cost. D.T.E. 99-19, at 25; D.P.U. 98-128, at 55; Bay State Gas Company, D.T.E. 98-31, at 17-18 (1998). Additionally, any company seeking recovery of an exogenous cost bears the burden of demonstrating the propriety of the exogenous cost and

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50 Multiplying NSTAR Gas's total operating revenues of $499,895,237 by a factor of 0.001253 equals $626,369.

51 NSTAR Gas's testimony mistakenly refers to the source of GDP-PI as the U.S. Bureau of Labor Statistics rather than the U.S. Bureau of Economic Analysis.

that the proposed exogenous cost change has not been incorporated into the GDP-PI. D.P.U. 96-50 (Phase I) at 292-293; D.P.U. 94-50, at 171. For these reasons, the Department does not prejudge the qualification of any future events as exogenous costs and will consider each proposal for recovery of exogenous costs on a case-by-case basis. At the time it seeks exogenous cost recovery, NSTAR Gas must demonstrate that the event meets both the definition and threshold for exogenous costs approved herein. Moreover, with respect to the second category of qualifying costs, NSTAR Gas must demonstrate that the proposed costs for recovery are above and beyond the types of costs that the Company normally incurs for safety and reliability.

v. Double Recovery of Capital Costs

GSEP capital expenditures have a dedicated reconciling mechanism for accelerated cost recovery for replacement of aging or leaking natural gas infrastructure (M.D.P.U. No. 402S at 16-17). In the calculation of the X factor, capital additions cannot be separated based on rate treatment (e.g., GSEP versus non-GSEP) (Exhs. ES-JF/MF-2, at 30; ES-JF/MF-Rebuttal-1, at 59-60; DPU-ES 32-14). Thus, the calculation of TFP growth rate, and, therefore, the X factor, includes both GSEP and non-GSEP capital (Exh. DPU-ES 32-14).

The Department concludes that an adjustment for double recovery is not necessary. The PBRM, unlike the GSEP, is not a recovery mechanism, and therefore "double recovery" is not a concern. The X factor estimates productivity based on industry-wide past performance and is then applied to escalate the Company's revenue requirement as a whole. It is not intended for recovery of any specific costs (Exh. AG 9-2).

As discussed above, due to data limitations, there is not a reliable method for excluding GSEP-related capital for the industry from the X factor calculations (Exhs. ES-JF/MF-Rebuttal-1, at 59-60; DPU-AG 2-7; Tr. 11, at 1516-1518). Even with a reliable method of estimating the impact of GSEP on the X factor for the industry, the magnitude of the possible impact is likely to be small. The Company shows that in the data used for the TFP study, capital additions as a whole represent a small portion of real capital stock (3.5 to 4 percent), suggesting that there are other factors driving capital input quantity growth in the TFP and, therefore, impacting the X factor (Exh. DPU-ES 32-14). The Company also estimates that, using data for NSTAR Gas specifically, if it removed the Company's GSEP investments from capital stock, it would have a modest impact on the average annual growth of real capital stock, decreasing it by 0.3 percent, from 2.3 percent to 2.0 percent (Exh. DPU-ES 32-14). Finally, the GSEP program only accelerates the replacement of capital assets, so, over the long-term, the GSEP program will not materially impact the growth rate of total capital (Tr. 7, at 987-990). In sum, the impact of GSEP capital on the measure of TFP is insubstantial.

vi. Conclusion

In the sections above, the Department has reviewed the Company's PBR proposal and has found that, as approved, it is more likely than current regulation to advance the Department's traditional goals of safe, reliable, and least-cost service and to promote the objectives of economic efficiency, cost control, lower rates, and reduced administrative burden in regulation. In addition, the Department has found that the proposed PBR Plan, as approved, will provide NSTAR Gas with greater incentives to reduce costs than currently exist and should result in benefits to customers that are greater than would be present under current regulation. Further, the Department has found that the proposed PBR Plan, as approved, better satisfies our public policy goals and statutory obligations, including promotion of a safe and reliable gas pipeline infrastructure, and the Commonwealth's clean energy goals and mandates.

With the modifications to the PBR formula required herein, the Department finds that the PBRM appropriately balances ratepayer and shareholder risk, is in the public interest, and will result in just and reasonable rates pursuant to G.L. c. 164, § 94. Accordingly, the Department approves NSTAR Gas's proposed PBR, subject to the modifications above. NSTAR Gas, in its compliance filing, is directed to submit a revised PBR provision tariff consistent with the findings in this Order (Exh. ES-RDC/LMC-2 (Rev.) at 144-152).

Further, NSTAR Gas shall submit an annual PBR adjustment filing, including all information and supporting schedules necessary for the Department to review the proposed PBRM adjustment for the subsequent rate year. Such information shall include the results and supporting calculations of the PBRM adjustment factor formula, descriptions and accounting of any exogenous events, and an earnings sharing credit calculation for the year, two years prior to the rate adjustment. In addition, NSTAR Gas shall file revised summary rate tables reflecting the impact of applying the base distribution rate changes provided in the

PBRM adjustment filing. NSTAR Gas is directed to submit its annual PBRM adjustment filing on or before September 15 of each year, commencing in 2021 and continuing for the ten-year term of the PBR. Consistent with our findings above, the PBR shall continue in effect for a total of ten consecutive years starting November 1, 2020, with the last adjustment taking effect on November 1, 2029 and expiring on October 31, 2030.

## C. Scorecard Metrics

### 1. Introduction

The Company proposed scorecard metrics as an element of its PBR Plan (Exh. ES-WJA-DPH-1, at 8). The Company states that its proposed scorecard metrics are aligned with policy objectives set forth by the Department and will allow stakeholders to monitor the Company's progress during the five-year term of the PBR Plan (Exhs. ES-WJA-DPH-1, at 8-9, 101; ES-PMC/MRG-1, at 61). These scorecard metrics are designed to monitor progress toward important policy objectives, specifically related to safety and reliability; customer satisfaction and engagement; and emission reductions (Exh. ES-WJA-DPH-1, at 9, 100). The Company proposes a total of 12 scorecard metrics across these three categories (Exhs. ES-WJA-DPH-1, at 9, 102-103; ES-PMC/MRG-1, at 61). The Company proposes to report results on each scorecard metric as part of the annual PBR Plan compliance filings (Exh. ES-WJA-DPH-1, at 9, 103).

### 2. Company Proposal

#### a. Safety and Reliability

The Company proposed specific targets for the following five safety and reliability categories: (1) emergency response rate to Class I and Class II Odor Calls; (2) excavation damage occurrence rate to the Company's distribution system; (3) workplace safety as measured by a days away from work, restricted work activity, and/or job transfer rate ("DART Rate"); (4) speed of grade 2 gas leak repairs; and (5) the implementation of the Pipeline Safety Management System ("PSMS") (Exh. ES-WJA-DPH-1, at 102, 104-109). Where available, the Company used average past performance from 2016-2018 as a baseline and developed an improvement goal to achieve by year five of the PBR Plan term (Exh. ES-WJA-DPH-1, at 104-109).

b. Customer Satisfaction and Engagement

The Company proposed the following five metrics in the category of customer satisfaction and engagement: (1) the Company's J.D. Power's Gas Utility Residential Customer Satisfaction Study score for the Safety and Reliability index; (2) customer satisfaction with the Company's online tools using a one-to-ten survey rating; (3) digital engagement with self-service tools and alert notifications; (4) the average speed at which gas emergency calls are answered; and (5) customer satisfaction of the Company's performance on new gas service connections, using a one-to-ten survey rating (Exh. ES-PMC/MRG-1, at 64-72). The Company generally set targets based on incremental improvement over recent past performance (Exh. ES-PMC/MRG-1, at 65).

c. Emission Reductions

The Company proposes two metrics in the category of emission reductions: (1) methane emission reductions resulting from the GSEP program; and (2) the repair of non-GSEP environmentally significant grade 3 leaks on an accelerated timeframe compared to existing Department criteria (Exh. ES-WJA-DPH-1, at 110-113).

3. Positions of the Parties

a. Attorney General

The Attorney General argues that the Department should reject NSTAR Gas's proposed performance metrics because the Company's performance will not demonstrate whether the PBR has provided measurable customer benefits and that the targets proposed are no different than what has been achieved under rate of return regulation (Attorney General Brief at 138-140). Specifically, the Attorney General contends that the Company has already achieved, or nearly achieved, the proposed targets associated with its emergency response rate, DART Rate, grade 2 and 3 leak repairs, methane reductions, and PSMS implementation (Attorney General Brief at 140-145).

With respect to the emergency response rate, the Attorney General asserts that the proposed metric is simply a targeted performance for a subset of odor calls in the existing Department's Service Quality Guidelines ("SQ Guidelines") (Attorney General Brief at 140, citing Exh. AG-DDE-Surrebuttal-1, at 9). Further, the Attorney General maintains that NSTAR Gas already has surpassed its proposed target, with an average response rate of 96.11 percent within 45 minutes for the three years 2016 through 2018 (Attorney General Brief at 140, citing Exh. AG-DDE-1, at 6-7).

The Attorney General claims that the Company's proposed benchmark for its workforce measure of DART Rate is little more than what has already been achieved, noting the proposed improvement is a subjective ten-percent reduction from its three-year average DART Rate of 2.4 to 2.2 after five years (Attorney General Brief at 141). The Attorney General states that the Company's DART Rates for 2016 through 2019 were 2.671, 2.579, 1.872 and 1.645, respectively, and that the proposed target is higher than what already has been achieved (Attorney General Brief at 141, citing Exh. AG-DDE-1, at 10-11).

Regarding grade 2 leak repairs, the Attorney General explains that the Company's proposal is to commit to completing 75 percent of grade 2 leak repairs in nine months or less, which is three months faster than the Company is required by statute (Attorney General Brief at 142, citing Exh. ES-WJA/DPH-1, at 102). The Attorney General argues, however, that during 2016 through 2018 the Company was able to repair over 99 percent of grade 2 leaks within nine months, and 75 percent within two months (Attorney General Brief at 142, citing Exh. AG-DDE-1, at 14).

Regarding the Company's proposal to repair grade 3 leaks that are environmentally significant but not scheduled for GSEP repair within 12 months, the Attorney General insists that the target is lower than what has recently been achieved (Attorney General Brief at 142). Specifically, the Attorney General claims that the Company repaired 24 environmentally significant grade 3 leaks in 2019, and all were repaired within the two-year statutory requirement, with repairs taking an average of 290 days (Attorney General Brief at 142-143). Furthermore, the Attorney General asserts that the Company's proposal to complete grade 3 leak repairs within 12 months would not produce emissions reductions as the Company claims (Attorney General Brief at 143, citing Exh. AG-DDE-1, at 16).

Additionally, the Attorney General avers that the Company's proposed progress in emissions reductions associated with its GSEP program reflect nothing more than its existing GSEP schedule for leak-prone main and service replacements (Attorney General Brief at 143-144). Therefore, she argues that this metric does not promote improvements in utility operations (Attorney General Brief at 144).

Regarding the proposed metric for total damages per 1,000 work tickets, the Attorney General argues that the metric is likely to exhibit volatility over time, particularly between utilities and each utility's service territories, such that it will be difficult to determine whether any improvements are made (Attorney General Brief at 144). Moreover, the Attorney General claims that the Company's proposed reduction of ten percent over five years is unremarkable (Attorney General Brief at 144).

Regarding the Company's proposed PSMS implementation metric, the Attorney General argues that the goal of implementing all elements of its PSMS in three years is no different than the Company's prior commitment to implement a PSMS (Attorney General Brief at 144-145). The Attorney General contends that the proposed metric, like others, represents little to no added value for customers (Attorney General Brief at 145).

The Attorney General argues the Company's proposed customer service metrics are also lackluster (Attorney General Brief at 145). She notes that while the Company proposes to improve its service quality score as determined by J.D. Power, the Company's past performance was poor and below average compared to other utilities both regionally and nationally (Attorney General Brief at 145). Similarly, the Attorney General states the Company's proposal of a 22-point improvement in its 2018 Safety and Reliability score of 776 represents nothing more than a return to average performance and that NSTAR Gas should strive to make these improvements regardless of the form of rate regulation approved (Attorney General Brief at 145-146).

The Attorney General also takes issue with the Company's proposed Customer Satisfaction and Engagement metric, arguing that NSTAR Gas only had data for 2018 (Attorney General Brief at 146). With such limited data, the Attorney General argues assessing the reasonableness of any proposed improvement targets is not possible (Attorney General Brief at 146).

Finally, with respect to NSTAR Gas's proposed speed of answer metric for customer gas emergency phone calls, the Attorney General asserts that the Company's target of ten to 15 seconds is merely representative of existing industry standards and levels the Company has already achieved in recent years (Attorney General Brief at 146). The Attorney General insists that the Company is doing well and should be able to maintain its current level (Attorney General Brief at 146).

b. <u>DOER</u>

DOER argues that while the Company is not proposing any incentives or penalties with respect to the proposed scorecard metrics, the Company recognizes the value of reporting metrics (DOER Brief at 13). DOER contends that in order to develop performance metrics that can be tied to incentives and penalties in future cases, the Company should be directed to finalize and consistently report on the proposed scorecard metrics (DOER Brief at 13).

DOER also suggests that an additional scorecard metric that would track the Company's commitment to engaging stakeholders in a conversation about the role of the gas industry in achieving the GWSA goal of reducing emissions by 80 percent by 2050 (DOER Brief at 14, citing Exh. DPU--ES 36-10). DOER maintains that the metric should track engagement around the larger 2050 goal and should be completed no later than the Company's first PBR filing in 2021 (DOER Brief at 13).

c. TEC

TEC argues that the Department should reject the Company's proposed scorecard metrics (TEC Brief at 9). As an initial matter, TEC contends that the majority of the proposed metrics include items NSTAR Gas should be conducting as part of its regular business (TEC Brief at 9). TEC also claims that the Company has minimal incentive to achieve its proposed targets, as the metrics are not linked in any way to the Company's revenues (TEC Brief at 9).

d. Company

NSTAR Gas argues that its proposed suite of scorecard metrics are an integral part of the PBR plan, are aligned with the Department's policy objectives, and will allow the Department to monitor the Company's progress during the term of the PBR (Company Brief at 80; Company Reply Brief at 34). Responding to the Attorney General's critiques, the Company states that her position is based on the flawed inference that because the Company has achieved high levels of performance in recent years, the performance targets set for the metrics are easily achievable going forward (Company Brief at 93; Company Reply Brief at 34). NSTAR Gas maintains that such easy achievement is not the case, the future performance environment is not static, and that there exist practical limitations and challenges to achieving the same level of performance in the future due to changing operating conditions (Company Brief at 93; Company Reply Brief at 35, citing Exh. ES-WJA/PMC/MRG-Rebuttal-1, at 12).

Moreover, the Company contends that several of the proposed metrics, including the emergency response rate metric, have target levels that go above and beyond existing standards set by the Department (Company Brief at 93; Company Reply Brief at 35). Additionally, while NSTAR Gas has been able to achieve high levels of performance in recent years, it maintains that such performance was only achieved through prudent management of finite Company resources (Company Brief at 94; Company Reply Brief at 35).

The Company claims that TEC's assertion that the metrics include items the Company should be doing as part of business as usual is made without evidence or legal argument (Company Brief at 105). To the contrary, NSTAR Gas claims that the evidence clearly demonstrates that the proposed scorecard metrics go beyond business as usual and beyond existing Department standards (Company Brief at 106). Regarding concerns that the proposed metrics are not linked to any financial incentives or penalties, the Company states that the purpose of the metrics is to determine whether the PBRM is working as designed and providing benefit to customers (Company Brief at 106). Furthermore, the Company claims that while Massachusetts does not have penalties associated with its energy efficiency programs, Massachusetts has delivered the most successful energy efficiency program in the country (Company Brief at 107).

4. Analysis and Findings

a. Review Criteria

As discussed above, the Company has demonstrated that the LDC industry is rapidly changing and that a PBR Plan is the appropriate ratemaking model to allow the Company to adapt to this change. The Department must find, however, that the PBRM approved in this proceeding will result in just and reasonable rates. G.L. c. 164, § 94; D.P.U. 96-50 (Phase I) at 242; D.P.U 94-158, at 52-66. One factor that the Department considers is the extent to which the PBR Plan is designed to advance policy and other Department objectives to ensure that ratepayer benefits will result. D.P.U. 96-50 (Phase I) at 242. The Department has determined that a PBR proposal should: (1) be designed to achieve specific, measurable results; and (2) identify, where appropriate, measurable performance indicators and targets that are not unduly subject to miscalculation or manipulation. D.P.U. 94-158, at 63-64. The Department has further found that broader performance indicators are preferred and should be tied to the stated goals of a program and be consistent with the Department's regulatory goals. D.P.U. 94-158, at 63-64. Finally, the Department has determined that a well-designed PBR proposal should present a timetable for program implementation and specific milestones for program tracking and evaluation. D.P.U. 94-158, at 64-65.

NSTAR Gas has demonstrated that its costs are increasing due to several changes in the LDC industry including: (1) increases in safety and reliability standards; (2) environmental policy requirements; and (3) infrastructure constraints (Exhs. ES-WJA/DPH-1, at 88; DPU-ES 3-5). Through the adoption of the PBRM, the Department recognizes that NSTAR Gas requires the degree of flexibility to adapt to these changes. Accordingly, in order to measure the full range of benefits that will accrue under the PBRM, the Department finds that it is appropriate to establish a set of broad performance metrics that are tied to the goals of the PBRM and are consistent with the Department's regulatory objectives. In evaluating scorecard metrics, the Department needs to determine an appropriate suite of metrics to evaluate the ratepayer benefits created under the Company's PBRM (Exhs. ES-WJA/DPH-1, at 9; ES-PMC/MRG-1, at 6).

b. Safety and Reliability

As summarized above, the Company proposes a total of five individual metrics in this category. The Attorney General argues that the Company already has achieved the established performance targets for three of these metrics (emergency response rate within 45 minutes, DART rate, and total grade 2 leak repairs) and, therefore, the metrics as designed are unlikely to lead to improvements for ratepayers (Exh. AG-DDE-1, at 3, 9, 11, 14, 24-25). The Company counters, however, that the performance environment is not static, and that past high performance does not indicate how difficult it may be in future years to achieve the same result, particularly since it expects to face a changing operating environment going forward (Exh. ES-WJA/PMC/MRG-Rebuttal-1, at 12). The Department agrees with NSTAR Gas and recognizes that maintaining a high level of performance in an environment that is likely to include additional future challenges and difficulties is an appropriate goal.

Furthermore, maintaining a high level of achievement, and even increases that are "modest" as the Attorney General avers, results in ratepayer benefit.

With respect to the Attorney General's contention that the total damages per 1,000 tickets is too volatile to assess whether the proposed target results in a meaningful improvement, the Department finds this is not a persuasive reason to reject the metric. As NSTAR Gas correctly points out, this metric is important for tracking the effectiveness of the Company's damage prevention program (Exh. ES-WJA/PMC/MRG-Rebuttal-1, at 14). The Department does, however, direct that the Company expand the metric to include, in addition to total damages per 1,000 tickets: (1) total at-fault damages per 1,000 tickets; (2) total at-fault damages due to records per 1,000 tickets; (3) total at-fault damages due to human error per 1,000 tickets; (4) total damages not-at-fault per 1,000 tickets; (5) cost of at-fault damages; (6) cost of not-at-fault damages; and (7) costs recovered for not-at-fault damages. This additional reporting will provide the Department with more insight and information with which to evaluate the Company's progress in safety over the course of the PBR term and better allow the Department to assess the impacts of damages that are the Company's fault, versus those that are not. The Department directs the Company to provide a three-year history of the aforementioned metrics in order to establish an appropriate benchmark.

The fifth scorecard metric proposed to track safety and reliability performance is PSMS implementation. The Company proposes to have a third party evaluate the progress of the Company's implementation in their PSMS, based on a standard framework, with the goals of achieving certain implementation levels within three years and maintaining that performance level in future years (Exh. ES-WJA/DPH-1, at 109-110). The Attorney General points out that the Company has not indicated whether this metric represents an incremental commitment beyond what they would have done absent the PBR Plan (Exh. AG-DDE-Surrebuttal-1, at 23). Further, the Attorney General notes that reporting on PSMS implementation progress does not necessarily provide value-added for ratepayers (Exh. AG-DDE-Surrebuttal-1, at 23). The Department disagrees and finds that the Company's commitment to a level of achievement within a specified timeline is not only incremental but will result in improvements in safety and reliability, and ultimately, ratepayer benefits.

Upon review, the Department finds that the proposed scorecard metrics track the Company's performance in the important area of safety and reliability, with appropriately developed baselines. These metrics will measure the progress that the Company makes to improve pipeline safety and service reliability over the term of the PBR Plan, and as such are approved. Therefore, the Department directs the Company to implement the safety and reliability scorecard metrics, including the additional metrics related to damages, and to include the results in its annual PBR filing.

c. Customer Satisfaction and Engagement

As described above, the Company proposes five scorecard metrics related to customer satisfaction and engagement. First, regarding the metric for improving the Company's score on the J.D. Power Survey Safety & Reliability Factor, the Attorney General argues that a lack of historical data makes it difficult to assign a goal with any confidence; however, the

Attorney General agrees with the Company that a goal of improving on what she argues are low scores is sensible, and therefore the metric should not be ruled out (Exh. AG-DDE-Surrebuttal-1, at 24-25). Regarding the metrics based on the Company's web satisfaction survey and digital engagement, the Attorney General similarly suggests that a lack of historical data from which to develop a baseline makes it difficult to set an appropriate target; and, therefore, the metrics may be helpful to track, but will not provide information in terms of justifying a PBR Plan (Exh. AG-DDE-Surrebuttal-1, at 26). The Department is not persuaded that a lack of historical data is an appropriate reason to reject either proposed metric, as additional reporting over time will ameliorate any concerns and allow the Department to assess improvements. The Department has previously accepted metrics based on only one year of data, so approval of these metrics and targets is consistent with Department precedent. D.P.U. 18-150, at 88, 89.

Furthermore, the Department finds that measurements and improvements in customer satisfaction are important and there is value in such metrics as part of a PBR plan evaluation. In assessing whether ratepayers have benefited from the PBR Plan, the Department will examine any improvements in customer satisfaction engagement.

Based on our review, the Department finds that these scorecard metrics as proposed track the quality and convenience of customer interaction with appropriately developed baselines. These metrics will measure the progress that the Company makes to improve customer satisfaction and engagement over the term of the PBR Plan, and as such are approved. Therefore, the Department directs the Company to implement the customer satisfaction and engagement scorecard metrics and to include the results in its annual PBR filing.

d. Emission Reductions

For NSTAR Gas's first emission reduction scorecard metric, the Company proposed to track emission reductions resulting from implementation of the GSEP program, reducing methane emissions by 39 percent from 2018 levels by the end of the PBR Plan term (Exh. ES-WJA/DPH-1, at 110). The Attorney General claims that this proposed scorecard metric does not demonstrate any benefit to ratepayers because the GSEP program already is providing the benefits that will be tracked by this metric (Exh. AG-DDE-Surrebuttal-1, at 20). The Company counters that the ability to achieve the goal is still an indicator of the Company's ability to properly manage the GSEP program among all other necessary work to provide safe and reliable natural gas service and further argues that the source of funding for the reduction should not matter (Exh. ES-WJA/PMC/MRG-Rebuttal-1, at 27). While this metric specifically relates to the GSEP program, the Department agrees that the metric would provide an assurance that the Company is managing its GSEP program in light of the future uncertainties in the gas distribution industry and that a PBR plan's success includes a determination that a utility has managed its costs and policy goals in a holistic manner.

The Company's second emission reduction scorecard metric sets a goal of exceeding the statutory requirement for the timeline to repair grade 3 environmentally-significant leaks and commits to repair 100 percent of non-GSEP leaks within twelve months of leak designation (Exh. ES-WJA/DPH-1, at 111-112). The Attorney General argues that the proposed target may not have the intended effect of reducing emissions and that the Company already has surpassed its proposed target in recent years (Exh. AG-DDE-1, at 16). Here, as above, the Department finds that the fact that the Company has met its proposed target in certain prior years does not mean that achieving these goals going forward will be easy and without challenges. Emission reductions are important from an environmental and policy perspective, and any improvement from the statutory requirements is a noteworthy goal that benefits customers.

Regarding DOER's suggestion for an additional scorecard metric tracking the Company's commitment to engaging stakeholders in a conversation about the role of the gas industry in achieving the GWSA goal of reducing emissions by 80 percent by 2050, the Department finds that such a metric would be a useful addition to those proposed by NSTAR Gas, particularly given the importance of emissions reductions. Moreover, the Company has indicated that it recently announced an industry-leading goal to be carbon neutral by the year 2030 (Exh. DPU-ES 36-10). While a specific metric and target has not been proposed by any party, the Company notes that it is in the process of developing an internal tracking metric for these efforts (Exh. DPU-ES 36-10). Accordingly, the Department directs the Company to provide, as part of its first PBR filing, a scorecard metric that tracks engagement around the larger 2050 goal, and, to the extent possible, any efforts toward the aggressive 2030 goal.

e. Conclusion

As discussed above, the Department has approved all the Company's proposed scorecard metrics, including a modification to its metric for total damages per 1,000 Tickets. Moreover, the Department directed the Company to include an additional scorecard metric to track stakeholder engagement around the 2050 goal to reduce emissions by 80 percent, and, to the extent possible, any efforts toward the Company's carbon neutral by 2030 goal. Accordingly, the Department directs to Company to report on these approved scorecard metrics its annual PBR filings.

## VI. DEMONSTRATION PROJECTS

### A. Gas Demand Response Demonstration Project

#### 1. Introduction

The Company proposed a three-year natural gas demand demonstration project to facilitate the study of the effectiveness, scalability, and ability of demand response to mitigate natural gas demand spikes and to relieve pipeline capacity constraints (Exh. ES-WJA/DPH-1, at 69-70). Specifically, the Company stated that the results of the project will allow it to evaluate whether gas demand response could effectively: (1) reduce the demand for liquefied natural gas ("LNG") during the coldest days; (2) increase reliability in "single feed" pipeline systems' susceptible to capacity constraints; and/or (3) reduce gas usage during peak hours and/or overall (Exh. ES-PMC/MRG-1, at 31).[52] The Company noted that the project is the

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[52] The Company states that the proposed demand response demonstration will not conflict with the temperature optimization offering approved in the Company's most recent three-year energy efficiency plan, which does not provide any customer incentives other than modest savings as a result of gradually adjusting the set points

first of its kind in Massachusetts and that its design is informed by gas demand response pilot projects conducted in New York and California, as well as by Eversource's own experience running an electric demand response program (Exhs. ES-PMC/MRG-1, at 43; DPU-ES 2-6; DPU-ES 2-7; DPU-ES 2-8; DPU-ES 2-9; DPU-ES 2-14). Through this proposal, NSTAR Gas intended to: (1) determine the impacts on customer comfort; (2) determine the appropriate incentive levels to induce participation; (3) determine the appropriate metering configuration to measure gas usage; and (4) study the most common strategies used by customers to reduce gas usage (Exh. ES-PMC/MRG-1, at 33, 35).

The Company anticipated 3,000 residential participants and 50 commercial and industrial ("C&I") participants based on information from the Company's electric demand response program vendor and its analysis of eligible C&I customers (Exhs. ES-PMC/MRG-1, at 41; DPU-ES 2-9). To participate in the demand response project, residential customers must have a gas furnace or boiler connected to a Wi-Fi thermostat (Exh. ES-PMC/MRG-1, at 37). Residential participants will be called on to participate in three to eight demand response events each heating season (November through March), which will be dispatched between 6:00 a.m. and 9:00 a.m. (Exh. ES-PMC/MRG-1, at 37-38).[53] During a demand

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on the customer's Wi-Fi thermostat (Exh. DPU-ES 9-1, citing 2019-2021 Three-Year Energy Efficiency Plans Order, D.P.U. 18-110 through D.P.U. 18-119 at 39 (2019)). The Company states that commercial customers are likely to participate in only one of the two strategies (Exh. DPU-ES-9-1).

[53] Each event will be determined by a temperature threshold based on ongoing weather observations (Exh. DPU-ES 2-12). Participants will get notice on the day prior to an event and can opt out at any time by changing their thermostat set point during an event (Exhs. ES-PMC/MRG-1, at 37; AG 17-05).

response event, participants will have their heating set point automatically lowered one to three degree(s) for two to eight hours through their Wi-Fi thermostat (Exh. ES-PMC/MRG-1, at 35-38). Residential participants will receive a $25 incentive to enroll and a $20 incentive per heating season (Exhs. ES-PMC/MRG-1, at 37-38; DPU-ES 20-1). During the proceeding, the Company revised its initial residential proposal to exclude renters from participating in instances where the landlord has direct control of the thermostat because this customer subset has a limited ability to reduce their own gas usage (Exh. ES-WJA/PMC/MRG-Rebuttal-1, at 43-44).[54]

The C&I component of the project will use a technology agnostic approach requiring participants to reduce their load without the use of a liquid fossil fuel backup (Exh. ES-PMC/MRG-1, at 36). C&I customers will be eligible to participate only if they commit to 50 therms of curtailable load per event or per season (Exh. ES-PMC/MRG-1, at 36-37). C&I participants will receive an incentive on a pay-for-performance basis during peak hours ($45 per therm), as well as bonuses for reductions in usage over a 24-hour period ($2 per therm) (Exh. ES-PMC/MRG-1, at 36-37). The Company will prioritize peak period reductions especially for large C&I customers who are served off the constrained Algonquin G-lateral (Exhs. DPU-ES 20-2; DPU-ES 31-4). The Company will work alongside its sales

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[54] The Massachusetts Department of Public Health requires a minimum temperature of 68 degrees during the day and 64 degrees at night in homes where the landlord has direct control of the heat (Exh. ES-PMC/MRG-1, at 42, citing 105 CMR 410.201). The Company will allow for lower temperature set points only for renters and homeowners who have direct control of their heat (Exhs. AG 12-17; DPU-ES 31-2; ES-WJA/PMC/MRG-Rebuttal-1, at 43-44).

team or with curtailment service providers to identify and target customers served by the Algonquin G-lateral for participation in the demonstration project (Tr. 1, at 136-137).

The Company estimated that the total cost of the demonstration project is $2,305,729 (Exh. ES-PMC/MRG-1, at 41).[55] The Company will conduct a request for proposals ("RFP") for two evaluation firms: one to evaluate the direct results of the demonstration project; and one to evaluate the avoided costs associated with a scaled gas demand response project (Exhs. DPU-ES 9-2; DPU-ES 9-3). The Company intends to use a framework akin to the Avoided Energy Supply Cost Study ("AESC") to evaluate the avoided costs from natural gas demand response, either independently or as part of a statewide effort (Exhs. ES-PMC/MRG-1, at 29; DPU-ES 2-3). As described above, the Company proposes to recover estimated project costs through the Y factor, with actual costs reconciled annually. The Company proposes to allocate program costs to each customer class using the base distribution revenue allocator (Exhs. ES-WJA/DPH-1, at 89-90; proposed M.D.P.U. No. 411, § 11).

2. <u>Positions of the Parties</u>

a. <u>Attorney General</u>

The Attorney General supports the Company's gas demand response project and considers it to be generally sound and a positive step in the right direction (Attorney General

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55 The costs are broken down as follows: $1,017,500 in Year One, $648,425 in Year Two, and $639,804 in Year Three (Exh. ES-PMC/MRG-1, at 41). The total costs include $300,000 for incremental labor, and $250,000 for evaluation costs (Exh. ES-PMC/MRG-1, at 41).

Brief at 157). However, the Attorney General recommends that the Company modify its proposal to: (1) revise the proposed participant incentives to more accurately reflect avoided costs; and (2) measure participant electricity usage to ensure gas demand reductions are not offset by an increase in electricity use (Attorney General Brief at 157-159, citing Exh. AG-JDM-1, at 8).

First, the Attorney General argues that the Company's participant incentives should be revised to account for the avoided gas costs and other savings specific to NSTAR Gas customers instead of mimicking those used in Consolidated Edison Company of New York, Inc.'s ("ConEd") gas demand response program (Attorney General Brief at 157-158, citing Exh. DPU-ES 9-7). The Attorney General insists that NSTAR Gas should have a reasonable estimate of the potential savings associated with the project on a per-therm basis (Attorney General Brief at 158, 160). Additionally, the Attorney General argues that because NSTAR Gas does not procure gas supply for capacity-exempt[56] or capacity-eligible customers, the savings generated from these customers will differ from typical sales customers and the customer incentives should be adjusted accordingly (Attorney General Brief at 158).

Second, the Attorney General asserts that the Company should be required to monitor and report electricity use of the project participants (Attorney General Brief at 159). The

56 Capacity-exempt customers are either new customers who have elected to go directly to marketer service, or customers who were receiving transportation-only service prior to the unbundling of gas services in 1998 and for whom the gas companies have no obligation to procure pipeline capacity. Emergency Authorization for Gas Capacity Planning, D.P.U. 14-111, at 2 n.1 (2014).

Attorney General maintains that participants may use electric space heaters to supplement their heating needs during demand response events. The Attorney General contends that electric generation will continue to be significantly dependent on natural gas in the three-year term of this project and, therefore, that increased electricity use could counteract the near-term GHG emissions reductions (Attorney General Brief at 159).

b. DOER

DOER asserts that the Company's proposal is consistent with the Commonwealth's policies and goals to reduce GHG emissions, including the Green Communities Act[57] (DOER Brief at 11, citing G.L. c. 25, § 21(a)). DOER supports the proposed demand response demonstration project but argues that the project is better suited as a midterm modification to the Company's three-year energy efficiency plan developed pursuant to G.L. c. 25, § 21[58] (DOER Brief at 11). DOER contends that the project would qualify as a hard-to-measure offering[59] and, therefore, the Company does not need to demonstrate that the benefits exceed the costs to propose the project within its energy efficiency plan (DOER Reply Brief at 12, citing NSTAR Electric Company/Western Massachusetts Electric Company, D.P.U. 16-178,

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57 An Act Relative to Green Communities, St. 2008, c. 169.

58 Pursuant to G.L. c. 25, § 21(b)(1), every three years the natural gas companies must jointly prepare a three-year, statewide energy efficiency plan in coordination with the Energy Efficiency Advisory Council ("EEAC").

59 A hard-to-measure offering refers to an offering that might not have immediate energy savings or whose energy savings may be difficult to quantify including, but not limited to: [...] (e) pilot programs; and (f) new types of programs (e.g., combined heat and power projects and demand response programs). Energy Efficiency Guidelines, D.P.U. 11-120-A, Phase II, § 2(11) (2013).

at 29 (2017); 2019-2021 Three-Year Energy Efficiency Plans, D.P.U. 18-110 through D.P.U. 18-119, at 166, Table 13.10 (2019) ("2019-2021 Three-Year Plans Order")).

DOER avers that the Department recently directed gas program administrators to submit testimony regarding the potential for cost-effective savings from gas demand response offerings (DOER Brief at 11, citing 2019-2021 Three-Year Plans Order at 40). Therefore, DOER argues that the project should be conducted within the three-year planning process to comply with the Department's Order (DOER Reply Brief at 11). If proposed as a midterm modification, DOER asserts that the Company will be able to evaluate the potential cost effectiveness of gas demand response and would be required to disclose its findings and receive feedback from stakeholders (DOER Reply Brief at 11). DOER also maintains that moving the proposal to the energy efficiency framework, where a focus is to incentivize changes in customer behavior, would justify the existing incentives and render irrelevant the Attorney General's and TEC's arguments that the incentives should accurately reflect avoided costs (DOER Reply Brief at 9, citing Attorney General Brief at 157; TEC Brief at 11). Additionally, DOER requests that the Department require the Company to evaluate avoided costs as a supplement to the AESC (DOER Initial Brief at 11-12, citing Tr. 1, at 127-130). In the event that the Department approves this demonstration project in the instant proceeding, DOER recommends that the Department require that NSTAR Gas consult with the EEAC first (DOER Reply Brief at 8-9).

Finally, DOER asserts that the Department should not allow dual-fuel customers to participate in the demand response project (DOER Reply Brief at 12). DOER contends that the demonstration project is appropriately focused on measuring the potential to relieve "extreme constraints" on the gas system and insists that TEC's recommendation regarding fuel switching is beyond the scope of the project (DOER Reply Brief at 13, citing Company Brief at 487; TEC Brief at 13-14). However, DOER recognizes the importance of understanding the impacts of gas demand response on the electric grid if offered at full-scale (DOER Reply Brief at 13). As such, DOER supports the Attorney General's recommendation that the Company measure electric usage for project participants (DOER Reply Brief at 13).

c. TEC

TEC supports the Company's objective to test a gas demand response project, but argues that the Company has failed to provide a persuasive argument to recover the cost of the C&I portion of the project through the PBRM (TEC Brief at 10; TEC Reply Brief at 5). According to TEC, the standard established in D.P.U. 16-178 applied primarily to the deployment of new technologies (TEC Brief at 10). TEC argues that, while a residential gas curtailment project is technologically novel, interruptible gas programs have existed in Massachusetts for decades and that methods to value peak day gas curtailment are available. TEC argues that the Department should require the Company to recalculate the incentive for C&I participants to reflect the avoided costs unique to the Company (TEC Initial Brief at 11). TEC elaborates that peak day curtailment for C&I users can be estimated using the AESC, Demand Reduction Induced Price Effects, or the Marginal Cost Study (TEC Brief at 10). Further, TEC maintains that the project is better suited for energy efficiency where the project's cost effectiveness can be appropriately measured, which ultimately determines the allowance of cost recovery (TEC Brief at 11).

Additionally, TEC argues that the exclusion of delivered-fuel backup heating from the demonstration project is unnecessary (TEC Brief at 12). TEC maintains that if allowed to participate, a dual-fuel facility could switch away from natural gas during a demand response event and free up capacity to serve other gas customers or power generation needs, which could reduce generators' need to call on LNG on the coldest days (TEC Initial Brief at 12-13). TEC argues that a dual-fuel customer switching to ultra-low-sulfur diesel during a demand response event will produce less emissions than if it were to increase its electricity usage when ISO-New England, Inc., is likely relying on the use of LNG at peaking power plants (TEC Brief at 13).

d. Company

The Company argues that its proposed demand response demonstration projects meets each of the factors considered by the Department when it evaluates a pilot project: (1) the consistency of the proposed demonstration program with applicable laws, policies, and precedent; (2) the reasonableness of the size, scope, and scale of the proposed projects in relation to the likely benefits to be achieved; (3) the adequacy of the proposed performance metrics and evaluation plans; and (4) bill impacts to customers (Company Brief at 477, citing D.P.U. 17-05, at 457).

First, the Company asserts that the demand response project is consistent with the Global Warming Solutions Act and the Commonwealth's emissions reduction targets and has the potential to relieve supply constraints thereby improving system reliability (Company Brief at 477-478, citing G.L. c. 21N, §§ 3(b), 4(a); St. 2008. c. 298, § 6; Kain et al. v. Department of Environmental Protection, 474 Mass. 278, 288-290 (2016)). Second, the Company avers that, consistent with the Department's requirements, it provided a detailed description of the proposal, analysis, and cost estimates that demonstrate the project's potential to deliver the following benefits: (1) reduction of GHG emissions; (2) insight into the amount of gas that can be saved through demand reduction; (3) reduction in demand of natural gas and LNG during peak periods; (4) avoided supply and capacity costs (Company Brief at 478, citing D.P.U. 17-05, at 460; Exh. ES-PMC/MRG-1, at 30-35). Third, the Company argues that it has proposed a robust evaluation plan to answer the proposed research questions and to quantify the project's benefits and that it will provide the results to the Department and interested stakeholders (Company Brief at 479, citing Exhs. ES-PMC/MRG-1, at 33; DPU-ES 2-16; DPU-ES 9-2; DPU-ES 9-3; AG 12-11). Fourth, the Company claims that it will contain costs through a competitive RFP process and asserts that the annual bill impact will be minimal in relation to the potential environmental and operational benefits (Company Brief at 480).

In response to DOER, the Company maintains that it is appropriate to review the demonstration project outside of the energy efficiency context because the project can neither meet the requirements for cost effectiveness nor the criteria to be considered a hard-to-measure offering (Company Brief at 484-485, citing Exh. DPU-ES 2-1). The Company explains that the Total Resource Cost ("TRC") Test required for energy efficiency programs must include all quantifiable benefits and costs, including how much natural gas has been reduced or shifted and the value of that natural gas (Company Brief at 484, citing Energy Efficiency Guidelines, D.P.U. 11-120-A, Phase II, § 3.4.3 (2013) ("Guidelines")). The Company insists that it is unable to estimate the potential savings or benefits for the proposed demonstration project that are necessary to meet the criteria of a hard-to-measure project, but that savings and benefits could be quantified by implementing the demonstration project (Company Brief at 484-485, citing Guidelines, § 3.4.3.2; Exh. DPU-ES 2-11; Tr. 1, at 131-136, 158-159, 161; Company Reply Brief at 88). Finally, the Company argues that it would not be practical to propose the project as a midterm modification plan from a timing perspective (Company Reply Brief at 89). The Company argues that an order in this proceeding would not be issued in time for the Company to submit a midterm modification for this three-year term for both EEAC and Department review (Company Reply Brief at 89).

With respect to DOER's alternative proposal, NSTAR Gas alleges that it would be inappropriate to have the EEAC in an oversight role if the project is approved as part of the PBR Plan since the proposal would not be part of a three-year plan (Company Brief at 485, citing G.L. c. 25, § 22). The Company contends that conducting the project outside of the energy efficiency context will not restrict stakeholders' access to the results, since project information will be included in its annual PBRM filing (Company Brief at 486, citing Exh. ES-PMC/MRG-1, at 41; Company Reply Brief at 90).

The Company maintains that the Department should reject the Attorney General's and TEC's proposed modification to the incentive structure (Company Brief at 481-483, 486). The Company contends that the proposed residential incentives are identical to those designed to incentivize participation in its electric demand response program (Company Brief at 481, citing Exhs. ES-WJA/PMC/MRG-Rebuttal-1, at 44; DPU-ES 9-7). Similarly, the Company argues that the proposed C&I incentives are designed to send adequate price signals to participants (Company Brief at 481). Further, NSTAR Gas asserts that it would be premature to introduce incentives differentiated by customer type prior to studying the actual effects of the project (Company Brief at 482).

NSTAR Gas argues that the Department should reject the Attorney General's and DOER's request that the Company monitor participant's electricity use (Company Brief at 482; Company Reply Brief at 91). The Company contends that the request would add costs to the study, that the increased electricity usage would be too small for the Company to operationalize, and that the request fails to account for the state's long-term energy policies to develop large-scale, carbon free, electricity generation (Company Brief at 482; Company Reply Brief at 91).

In response to TEC's request to allow dual-fuel customers to participate in the demonstration, the Company emphasizes that the exclusion of dual-fuel customers ensures an overall beneficial environmental impact (Company Brief at 487; Company Reply Brief at 85). The Company contends that TEC's recommendation is ill-conceived and inconsistent with the purpose and design of the Company's proposal (Company Brief at 487).

3. Analysis and Findings

In the most recent three-year plan Order, the Department found that the local gas distribution companies ("gas Program Administrators") had not convincingly shown that further exploration into potential savings from gas demand response was unsuitable. 2019-2021 Three-Year Plans Order at 40. The Department directed the gas Program Administrators to study the potential for gas demand response and submit testimony on the findings in the companies' subsequent three-year plan to be filed on or before October 31, 2021. 2019-2021 Three-Year Plans Order at 40. The Department expected the gas Program Administrators, including NSTAR Gas, to approach demand response through the collaborative three-year planning process, which has previously fostered the development of new, innovative offerings included in the statewide three-year plan. See D.P.U. 16-178; 2019-2021 Three-Year Plans Order at 30; see also Fitchburg Gas and Electric Light Company, et al., D.P.U. 20-33 through D.P.U. 20-36 (July 28, 2020) (approving electric demand response offerings).

On the record before us, the Department cannot find a convincing justification for why the Company proposed its demand response demonstration project, which targets peak demand reductions, as part of its PBR Plan rather than as a part of its three-year plan in accordance with the Department's directive. 2019-2021 Three-Year Plans Order at 40. The demand reduction proposals set forth by the Company are the type of peak demand reduction offerings contemplated by both the Green Communities Act and the Department's Guidelines for inclusion in the statewide three-year plan. G.L. c. 25, § 21(b)(1);

Guidelines, §§ 3.4.2-3.4.3.3. Further, the Company's proposal follows the same framework as most demonstration offerings that the Department has reviewed in previous three-year plans. The Department finds that (1) the proposed project is not dissimilar to other energy efficiency demand reduction demonstration projects and (2) the project stands to benefit all gas Program Administrators and gas energy efficiency as a whole. The Department notes that the project has the potential to satisfy the definition of all available demand-reduction resources that are cost effective or less expensive than supply, pursuant to the Green Communities Act. G.L. c. 25, § 21(a).[60] Therefore, the Department finds that the review of this proposed gas demand response demonstration project more appropriately fits into the energy efficiency regulatory framework.[61] G.L. c. 25, § 21(b)(1). Accordingly, the Department denies the Company's proposal to run a gas demand response demonstration as part of its PBR Plan. The Company should work jointly with other gas Program Administrators pursuant to G.L. c. 25, §§ 21, 22 and the Department's directives before

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60 The Department notes that while energy efficiency programs proposed in a three-year plan must be screened for cost-effectiveness under the TRC test, the Department does not require a demonstration project to be cost-effective. Fitchburg Electric Light Company, D.P.U. 16-184, at 12 (2017). Demonstration projects are also not the same as traditional hard-to-measure offerings; however, the Department will screen these projects in the same manner as hard-to-measure offerings during the initial testing stage (i.e., the addition of a demonstration project to the portfolio must not result in a sector's benefit-cost ratio falling below one). D.P.U. 16-184, at 12.

61 The Department notes that its finding regarding this specific proposed demand response project does not preclude other non-peak demand reduction projects from being proposed outside the energy efficiency regulatory framework.

submitting a gas demand reduction demonstration project proposal to the Department for review.[62, 63] See D.P.U. 16-178, at 27, 39, 44; 2019-2021 Three-Year Plans Order, at 40. Given our decision to deny the Company's proposal, we will not address the intervenors' recommendations concerning incentive levels and the participation of dual-fuel customers. The intervenors may take advantage of the stakeholder process at the EEAC to provide formal feedback and to better foster the collaborative process for gas demand response.

62 Any proposed gas demand reduction demonstration project should address the following factors: (1) the consistency of the proposed demonstration program with applicable laws, policies, and precedent; (2) the reasonableness of the size, scope, and scale of the proposed projects in relation to the likely benefits to be achieved; (3) the adequacy of the proposed performance metrics and evaluation plans; and (4) bill impacts to customers. D.P.U. 16-178, at 26. The Department takes this opportunity to clarify that one potential purpose of a demonstration project is to better understand the potential savings of a measure or strategy. Therefore, the Department does not require that a gas Program Administrator fully quantify benefits associated with a proposed project, but only provide the best available estimates of the savings and benefits from the proposed project.

63 The Department notes that the Program Administrators should rely on existing information, to the extent appropriate, to assist them in their own evaluations of the opportunities for demand response as a resource in Massachusetts. 2016-2018 Three-Year Plans Order, at 143. Further, the Program Administrators must ensure that any proposed demonstration project is not duplicative of other demand response demonstration offerings either underway or proposed. D.P.U. 16-184, at 14. The Department also notes that Eversource Gas of Massachusetts has been approved to implement a three-year gas demand response offering commencing November 2021. Eversource Energy/Bay State Gas Company Merger, D.P.U. 20-59, at 29, 63-65. Under that demonstration project, Eversource Gas of Massachusetts plans to temporarily reduce gas usage from residential and small commercial customers by changing setpoints on Wi-Fi thermostats that are connected to natural gas fired furnaces or boilers. D.P.U. 20-59, at 29.

## B. Geothermal Demonstration Project

### 1. Company Proposal

The Company stated that its geothermal demonstration project is intended to study the effectiveness and scalability of providing low-carbon heating and cooling to those not currently served by NSTAR Gas (Exh. ES-PMC/MRG-1, at 43). Specifically, the Company proposed to oversee the installation and operation of geothermal networks, which are ground-source heat pumps ("GSHPs") connected to a networked loop system designed to provide heating and cooling to multiple buildings in a geographic area (Exhs. ES-PMC/MRG-1, at 45, 48; DPU-ES 2-31, Att.(f) at 3).[64] NSTAR Gas provided that the proposed demonstration is designed to allow the Company to: (1) determine if geothermal networks are scalable; (2) test if geothermal energy could provide an alternative for customers not on a gas pipeline or who do not want to use natural gas; and (3) provide the Company with real world experience constructing and maintaining geothermal networks (Exh. ES-PMC/MRG-1, at 45). The Company stated that geothermal networks are an efficient heating and cooling alternative to natural gas or other delivered fuels and, thus, will

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64 Geothermal technologies take advantage of the relatively stable temperature of the ground (between 50 and 60 degrees Fahrenheit throughout the year) to provide heating and cooling (Exh. ES-PMC/MRG-1, at 44). The Company's proposed geothermal network uses a closed loop of underground heat-exchanging pipes that circulate water and/or antifreeze solution underground to absorb the soil's heat (in the winter) (Exhs. ES-PMC/MRG-1, at 44-45; DPU-ES 9-27). The water brings the heat to the Earth's surface and transfers it to a heat pump, which warms the air, then in-home ducts circulate the air (Exhs. ES-PMC/MRG-1, at 45).

support the Commonwealth's goal to reduce GHG emissions pursuant to the GWSA (Exh. ES-PMC/MRG-1, at 43, 45).

The geothermal demonstration project is designed to target three scenarios in NSTAR Gas's service territory that the Company stated will replicate the real-world conditions of a large-scale geothermal network (Exh. ES-PMC/MRG-1, at 47-48). Under Scenario 1, the Company proposed to target a low-income multi-family building to generate findings regarding serving a residential load with a density geographical footprint (Exh. ES-PMC/MRG-1, at 47-48). Under Scenario 2, the Company proposed to target a dense, mixed-use (residential and commercial) area to study efficiencies created by serving a mixed customer class with diverse loads (Exh. ES-PMC/MRG-1, at 47-48). Under Scenario 3, the Company proposed to target a low-density residential neighborhood that is designed to mimic the challenges involved with distances between structures and acquiring potential easements or permits to access required land (Exh. ES-PMC/MRG-1, at 47-48).

NSTAR Gas proposed to recover all geothermal demonstration project costs on a reconciling basis through a Y factor in the LDAC (proposed M.D.P.U. No. 402S, § 11; Exh. ES-WJA/DPH-1, at 90). The Company estimated that the demonstration project costs could total $14,061,769,[65] including the costs of drilling wells, installation of heat pumps, internal labor, in-home equipment (e.g., heat pump units, distribution piping, ductwork),

65 Initially, the Company estimated a total project cost of $12,810,645 but subsequently provided revised costs that corrected for a summation error (Exhs. ES-PMC/MRG-3, at 1; DPU-ES 20-17 (Rev.)).

installation costs, and evaluation (Exhs. ES-PMC/MRG-1, at 50-51, 53; DPU-ES 2-29; DPU-ES 2-30; DPU-ES 31-11, Att.). The total estimated cost comprises $2,243,339 for Scenario 1, $10,261,606 for Scenario 2, and $1,256,851 for Scenario 3 (Exh. DPU-ES 31-11, Att.). Once installed, the participant will own and maintain all in-home equipment, and the Company will own the geothermal network equipment outside the home (e.g., piping, pumps, control panels, cooling towers) (Exh. DPU-ES 9-20). The Company budgeted $300,000 for third-party evaluation of the demonstration project results (Exhs. ES-PMC/MRG-1, at 53; DPU-ES 31-11, Att.).

The Company proposes to charge participants a quarterly customer fee to establish a billing relationship and to test how to charge for this service in the future (Exh. ES-PMC/MRG-1, at 59).[66] Customer fee revenues will be used to offset the cost of the project (Exhs. DPU-ES 2-23; DPU-ES 31-11, Att. at 3).[67]

The Company explained that the project is specifically intended to test the feasibility of networked, utility-provided geothermal energy for participants too far away from a natural gas pipeline or who do not wish to use natural gas (Exhs. ES-PMC/MRG-1, at 45; DPU-ES

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[66] The proposed quarterly customer fees are as follows: $450 per low-income multi-family building ($15 per unit for 30 units); $600 per residential development ($60 per unit for ten units); and $6,000 per dense urban high-rise ($60 per unit for 100 units) (Exh. ES-PMC/MRG-3, at 5).

[67] The Company is not proposing to book the geothermal service costs and revenues as part of the Company's regulated (or unregulated) business line, instead the Company views the demonstration project as simply an avenue to yield information about the reliability, scalability, and cost-effectiveness of a geothermal network (Exhs. ES-PMC/MRG-1, at 59; DPU-ES 2-18; DPU-ES 2-19).

2-21; DPU-ES 2-12). The Company maintained that, although the proposed eligibility criteria does not preclude gas customers, it will prioritize participants that are well-matched for the scenarios described above, expected to generate environmental benefits, and likely to provide answers to the Company's research questions (Exhs. DPU-ES 9-13; DPU-ES 20-12).

2. Positions of the Parties

a. Attorney General

The Attorney General contends that the Company's customers should not bear the entire $14 million cost of the geothermal demonstration project (Attorney General Brief at 162; Attorney General Reply Brief at 55). The Attorney General maintains that geothermal networked heating represents a potential new business offering and revenue stream for the Company, and she avers that this new business would benefit the Company, its shareholders, as well as other investors in the existing market for geothermal systems (Attorney General Brief at 162, citing Exh. AG-DDE-1, at 40). The Attorney General contends, however, that the Company's existing gas ratepayers bear all the risks and costs associated with the project while the Company and its shareholders are entirely isolated from these same risks and costs (Attorney General Brief at 162).

The Attorney General maintains that, although reducing GHG emissions in the heating sector is a necessary goal and she supports research and testing of geothermal technology under real world operating conditions, the Department should not grant NSTAR Gas's ratepayer-funded project at this time because there are opportunities to learn more about geothermal without spending ratepayer money (Attorney General Reply Brief at 55-56). Specifically, the Attorney General claims that Eversource committed to conduct a comprehensive assessment of decarbonization strategies in the thermal heating sector, including geothermal heating in a settlement agreement currently before the Department (Attorney General Reply Brief at 56-57, citing Bay State Gas Company, D.P.U. 20-59, Settlement Appendix 6, at 3). Additionally, the Attorney General asserts that Eversource agreed to earmark $4 million dollars in the same proceeding to conduct a geothermal demonstration project in Massachusetts at no cost to ratepayers (Attorney General Reply Brief at 56 n.21, citing D.P.U. 20-59). Therefore, the Attorney General argues that the Department can support a full exploration of networked geothermal service by approving that settlement agreement in D.P.U. 20-59 (Attorney General Reply Brief at 56-57). The Attorney General elaborates that the proposal in the current proceeding is premature and would benefit from broader collaboration of stakeholders and a more robust record (Attorney General Reply Brief at 57). To address her concerns, the Attorney General argues that the Department should consider NSTAR Gas's proposal in the context of a generic statewide investigation (Attorney General Brief at 162).

b. DOER

DOER overall supports the Company's geothermal proposal with some modifications (DOER Brief at 3-4). Specifically, DOER maintains that the Department should deny cost recovery for Scenario 1 because it is not innovative or distinct (DOER Brief at 8). DOER asserts that there are existing non-networked geothermal systems serving multi-family buildings in Texas and New York whose information could be leveraged to inform the Company at a lower cost to ratepayers (DOER Brief at 8, citing Exh. AG-DDE-1, at 34-36).

Further, DOER contends that Scenario 1 is duplicative of Scenario 2, which would likely include a residential multi-family building by targeting a mixed-use urban environment (DOER Brief at 8, citing Exh. ES-PMC/MRG-1, at 169). DOER recommends that the Department disallow Scenario 1 and require that the Company include multi-family housing in Scenario 2 (DOER Brief at 8-9). Alternatively, DOER supports HEET's proposal to modify Scenario 1 using a phased approach in which Scenario 1 gradually expands over time to include other customers and allows the Company to gain experience in expanding its geothermal network (DOER Reply Brief at 1-2). DOER supports both Scenarios 2 and 3 because they will provide novel information that can support the expansion of networked geothermal systems in the Commonwealth (DOER Brief at 7).

Additionally, DOER argues that the Department should direct the Company to establish a formal stakeholder process for the site selection and evaluation of the demonstration project (DOER Brief at 9). DOER suggests a stakeholder process will ensure that feedback is incorporated where reasonable, and that ratepayer interests are represented (DOER Brief at 9).

DOER also defers to the Department's determination of whether a gas distribution company has the authority to own and operate a geothermal distribution system, including the authority to install a geothermal distribution system within a public way (DOER Brief at 10, citing Exhs. DPU-ES 2-18; AG 32-1).

c. HEET

HEET asserts that it created the GeoMicroDistrict, i.e., the concept of local gas distribution companies ("LDCs") harnessing their experience, legal status, and existing customer base to provide utility-scale renewable thermal energy (HEET Brief at 7). HEET contends that the Company's proposed project will provide increased safety, reliability, and access to renewable heating sources (HEET Brief at 2). Additionally, HEET suggests that the findings from the project will support the Commonwealth's emissions reduction policies and accelerate the electrification of the state (HEET Brief at 2). HEET claims that networked geothermal will initially reduce emissions from heating by 60 percent (HEET Brief at 7-8). Additionally, HEET contends that the long-term savings for customers that will result if geothermal is used to displace natural gas infrastructure and forego GSEP costs will outweigh the short-term costs of building geothermal infrastructure (HEET Brief at 26-27).

HEET argues that both residential scenarios (Scenario 1 and Scenario 3) would benefit from the inclusion of non-residential participants to diversify the load on the loop system (HEET Reply Brief at 5). However, HEET insists that the projects should be approved with a phased approach in which non-residential customers are added to the scenarios over time (HEET Brief at 17; HEET Reply Brief at 6). HEET argues that the phased approach would generate beneficial data allowing the quantification of efficiencies created from adding mixed-use customers (HEET Brief at 16-17).

HEET encourages the Department to adopt two recommendations to enhance the Company's proposal. First, HEET states that it collaborated with the Company to apply for a grant from the Geothermal Technologies Office of the U.S. Department of Energy ("DOE") (HEET Brief at 16, 23). If awarded, the DOE grant would require full data transparency, where all modeling that is developed and results generated would be publicly accessible (HEET Brief at 24). HEET proposes that the Department adopt the same data sharing and transparency requirements for this demonstration project (HEET Brief at 24-25). Further, HEET encourages the Company to merge its stakeholder process with HEET's quarterly "Community Charettes" meetings to benefit from ongoing stakeholder discussion and HEET's expertise (HEET Brief at 23-26).

Finally, HEET suggests that the Company should modify its proposal to include one backup heater and cooler on each shared loop, as opposed to installing individual backup heaters for each unit attached to the loop (HEET Brief at 28-29). HEET argues that a common heater and cooler for the loop will ensure that the water in the loop can be maintained at the design temperature of 40 to 80 degrees Fahrenheit and obviate the need for glycol and its associated costs, making this method more simple and less expensive than the initially proposed method (HEET Brief at 29).

d. Company

The Company argues that by reducing emissions for homes that use delivered fuels by 60 percent, geothermal networks have the potential to be a critical resource in supporting the Commonwealth's GHG emissions reduction targets (Company Brief at 452-453, citing

Executive Office of Energy and Environmental Affairs Determination of Statewide Emissions Limit for 2050, at 1 (April 22, 2020), available at: https://www.mass.gov/doc/final-signed-letter-of-determination-for-2050-emissions-limit/download (last visited October 20, 2020); 2015 Update to Commonwealth's Clean Energy and Climate Plan for 2020, at 16, 50 (December 31, 2015), available at: https://www.mass.gov/doc/clean-energy-and-climate-plan-for-2020/download (last visited October 20, 2020); Exhs. DPU-ES 9-12; DPU-ES 20-13). The Company posits that its proposed geothermal demonstration project will generate valuable insight and data regarding the scalability of a cleaner, safer, and quieter heating alternative (Company Brief at 453).[68] As a natural gas utility, the Company asserts that it is uniquely qualified to build geothermal networks through public ways, as well as experienced in safe excavation, pipe fusing, maintaining pumping equipment, maintaining pressure-regulating equipment, and managing leaks (Exhs. DPU-ES 2-18; DPU-ES 9-5; AG 32-1).

The Company alleges that there has been significant stakeholder involvement in the current proceeding (Company Brief at 455). Further, NSTAR Gas claims that it is not proposing the geothermal distribution network project for the purpose of generating shareholder benefits; rather, the project is intended only to test the viability of utility-scale geothermal networks and to generate useful data and insights for the benefit of all interested stakeholders (Company Brief at 458). The Company asserts that its existing customers will

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68 Additionally, the Company claims that the use of GSHPs represents one of the lowest operational cost alternatives for heating electrification (Exh. DPU-ES 2-25).

benefit from the resulting reductions in the Commonwealth's carbon emissions (Company Brief at 455).

In response to DOER's request that the Department disallow Scenario 1, the Company insists that running all three scenarios together will allow the Company to gain experience with a representative cross-section of participants (Company Brief at 458, citing Exhs. ES-PMC/MRG-1, at 46, 48; ES-WJA/PMC/MRG-Rebuttal-1, at 37; DPU-ES 2-25; DPU-ES 9-21; DOER ES-1-8; Tr. 1, at 26-27, 79, 82-84, 89, 110, 116). The Company argues that the existing multi-family buildings served by non-district geothermal systems cited by DOER are incomparable to Scenario 1 and are located outside the state, rendering the study of such a scenario in Massachusetts novel and important (Company Brief at 459). Further, the NSTAR Gas maintains that Scenario 1 should not be subsumed into Scenario 2 because the two scenarios are designed to study different aspects of providing geothermal: Scenario 1 is intended to study geothermal service in a multi-family building, while Scenario 2 is intended to study the interactive effects of varied heating loads (Company Brief at 459).

The Company argues that the Department should not require the adoption of a formal stakeholder process for the project's site selection and evaluation (Company Brief at 459). The Company maintains that it should have full control over the final decisions relating to site selection and project evaluation because it is ultimately responsible for the operations of the demonstration project. Further, NSTAR Gas suggests that its proposed internal stakeholder process will allow adequate avenues for stakeholder feedback (Company Brief at 460).

The Company argues that HEET's suggestion to use a shared backup heater is not practical because it fails to isolate participants from a potential failure of the shared-loop pumps or motors (Company Brief at 464). NSTAR Gas maintains that its proposed backup heating plan—where each participant maintains its own backup heating system—ensures that all participants have access to heating in the event that they are disconnected from the loop (Company Brief at 464).

3. Analysis and Findings

a. Introduction

The Department commends the Company for seeking out a new and innovative solution to reducing the state's carbon emissions in support of Massachusetts' goals to reduce its overall GHG emissions. As noted in Section VI.A above, in D.P.U. 16-178, the Department summarized the factors that we consider when evaluating a proposed demonstration project. In evaluating NSTAR Gas's proposed geothermal demonstration project, the Department considers the following criteria: (1) the consistency of the proposed demonstration program with applicable laws, policies, and precedent; (2) the reasonableness of the size, scope, and scale of the proposed projects in relation to the likely benefits to be achieved; (3) the adequacy of the proposed performance metrics and evaluation plans; and (4) bill impacts to customers. D.P.U. 16-178, at 26; D.P.U. 17-05, at 234; D.P.U. 16-184, at 11. Subject to the modifications and directives below, the Department approves the proposed demonstration project and allows NSTAR Gas to own and operate a geothermal network as part of this demonstration project.

b. Consistency with Applicable Laws, Policies, and Precedent

The Commonwealth has established aggressive emission reduction and clean energy policies. St.2008, c.298; Executive Office of Energy and Environmental Affairs Determination of Statewide Emissions Limit for 2050, at 1 (April 22, 2020); 2015 Update to Commonwealth's Clean Energy and Climate Plan for 2020, at 16, 50 (December 31, 2015) ("CECP"). Conversion of customers to cleaner energy sources is one of the key policies set forth in the CECP. Widespread adoption of geothermal networks has the potential to significantly reduce carbon emissions in the Commonwealth (Exhs. ES-PMC/MRG-1, at 43-46; DPU-ES 2-31, Att. (a) at 10, 12-15; DPU-ES 9-12 & Atts.; DPU-ES 20-13). However, large upfront capital costs and infrastructure maintenance outside an individual or entity's premises are significant barriers to widespread adoption of geothermal networks (Exh. ES-PMC-MRG-1, at 59).

In light of the potential of geothermal networks and the current barriers to realizing that potential, NSTAR Gas proposes to test the effectiveness and scalability of geothermal networks by leveraging the Company's experience with a capital-intensive business, underground infrastructure, long-lived assets, regulated service, and monitoring system conditions (Exh. ES-PMC-MRG-1, at 58-59). The Department finds that the intent of the Company's proposal is consistent with the GWSA and the Commonwealth's energy climate policies, including the statewide emissions limit for 2050. Further, the Department notes that the knowledge and insight obtained through this demonstration project may inform the policy development undertaken in Inquiry to Examine the Role of Massachusetts Gas Local Distribution Companies in Helping the Commonwealth to Achieve its 2050 Climate Goals, D.P.U. 20-80 Vote and Order Opening Investigation (October 29, 2020). Specifically, the experience of developing and maintaining a company-owned geothermal network could inform the potential regulatory policies related to broad scale geothermal deployment and the role of LDCs in the future. Accordingly, the Department finds that the proposed demonstration project is consistent with the Commonwealth's policies.

NSTAR Gas is required to comply with all applicable state and local permitting and approval requirements necessary to proceed with the installation and operation of the approved geothermal network scenario. Specifically, a key component of the proposal is to evaluate the viability of installing geothermal networks in public ways, which will necessarily require the Company to: (a) identify sites with sufficient willing participants to meet the Company's criteria; (b) gauge municipalities' interest in participating in and requirements for permitting the project; and (c) review the Company's existing easements, permits, licenses, and rights-of-way (Exhs. ES-PMC/MRG-1, at 59; AG 32-1).

c. Size, Scope, and Scale

i. Introduction

The Department must determine whether the size, scope, and scale of the NSTAR Gas's proposed scenarios are reasonable in relation to the likely benefits. D.P.U. 16-178, at 26. The purpose of NSTAR Gas's geothermal demonstration project is to advance knowledge in the field and to inform future application of geothermal technologies by generating data and insights about design, construction, and maintenance of geothermal networks (Exhs. DPU-ES 2-18; DPU-ES 31-15). Nonetheless, geothermal technology itself is not new (Exh. DPU-ES 2-31, Att. (a) at 24; Tr. 1, at 120). The novel aspect of NSTAR Gas's proposal is the use of geothermal distribution networks traveling through public ways that will, therefore, service customers over a wider geographical footprint compared with geothermal systems confined to a single property (Exhs. ES-PMC/MRG-1, at 59; ES-WJA/PMC/MRG-Rebuttal-1, at 40-41; DPU-ES 2-26; DPU-ES 2-31, Atts. (a)-(f); Tr. 1, at 21-22, 24-25, 120, 172-173). Accordingly, the proposed scenarios should be reasonably designed to gather information and insights on geothermal networks that will advance knowledge of their viability, effectiveness, and scalability in the field for the benefit of ratepayers.

ii. Scenario 1 – Single Multi-Family Building

Based on substantial record evidence, the Department finds that Scenario 1, a geothermal network serving a single multi-family building, is not reasonably designed to justify the costs to ratepayers. First, the technology for individual buildings or private properties to maintain a GSHP is available in the market, and government-sponsored programs and rebates to support those purchases already exist (Exh. DPU-ES 20-14). For example, the Company referenced multiple existing geothermal projects currently operational that serve individual buildings or small, private networks in Massachusetts (Exh. DPU-ES 20-14(f)). Further, the Company must ensure that any proposed demonstration project is not duplicative of other projects either underway or proposed. See

D.P.U. 16-184, at 14. Second, it is not clear from the record that a geothermal network serving a single building would add significant knowledge or insight on the installation or operation of a geothermal network in a public way, since installation in a public way may not be required (Exhs. ES-PMC/MRG-1, at 47; ES-WJA/PMC/MRG-Rebuttal-1, at 40-41; Tr. 1, at 25-26). Lastly, the Department agrees with the Attorney General that, to the extent that Scenario 1 is designed to learn about serving a geographical dense area, the scenario is redundant since Scenario 2 targets a dense urban environment that comprises residential and C&I customers. The Department finds that Scenario 2, however, not only examines the operation of geothermal network in a dense geographic area but also may provide lessons learned that will benefit the Company's ratepayers because the Company will test its ability to operate a geothermal network in public ways and the prevalence of the dense urban environment in NSTAR Gas's service territory (Tr. 1, at 81, 118, 174). Based on the record evidence in this proceeding, we are not persuaded that the data and insight targeted in Scenario 1 is not already available in the field or could not be obtained as part of Scenario 2. Therefore, NSTAR Gas's proposal to recover costs associated with Scenario 1 is denied.[69]

iii. Scenario 2 – Mixed Use, Dense Urban Environment

NSTAR Gas's proposed Scenario 2 seeks to evaluate a geothermal network servicing a large mixed-use profile in a dense urban environment, is reasonably designed to justify the costs to ratepayers (Exh. ES-PMC/MRG-1, at 47). The Department finds that the record

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69 Since the Department does not approve Scenario 1, we do not need to address HEET's recommendation to implement a phased approach with Scenario 1.

demonstrates that Scenario 2 presents the biggest opportunity as a result of the Company's unique ability as a LDC to build through the public way, and that the efficiencies borne from the diverse load offer the potential for the most value (Exh. DPU-ES 2-31, Att.(f) at 44, 46; Tr. 1, at 80-82, 118, 172-174).[70] Further, based on the evidence presented, there are no comparable, utility-run sites in the country (Exhs. DPU-ES 2-24; DPU-ES 20-14). The Department finds that Scenario 2: (a) is most uniquely served and studied by an LDC; (b) has the greatest potential in terms of thermal efficiency; and (c) appears to be the least studied (Exhs. DPU-ES 9-5; Tr. 1, at 80, 81-82). As such, the Department finds that the size, scope, and scale of Scenario 2 are reasonable in relation to the likely benefits to be achieved.[71] However, consistent with our decision to deny Scenario 1, the Department encourages the Company to consider including a low-income, multi-family building in the site selection process for Scenario 2. The Company shall explain its efforts and decision whether to include a low-income, multi-family building in Scenario 2 in the first filing for cost recovery.

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70 "The interconnection of [geothermal networks] provides the opportunity to add diverse heating and cooling loads that, in aggregate, would balance heating- and cooling-dominant building uses (i.e., residential and commercial, respectively) and improve overall efficiency. Moreover, these benefits would increase with the size and diversity of the interconnected system, and larger systems could provide increasing opportunity for low-cost, long-term thermal energy storage." (Exh. DPU-ES 2-31 Att.(f), at 46).

71 The Department commends the Company for its heightened level of proactive collaboration with stakeholders in developing Scenario 2, specifically in supporting HEET's application for the DOE grant to offset the costs to ratepayers (Exh. Tr. 1, at 45-48, 66-68).

iv. Scenario 3 – Residential Neighborhood

Based on substantial record evidence, the Department finds that Scenario 3, a geothermal network serving a residential neighborhood, is not reasonably designed to justify the costs to ratepayers (Exh. ES-PMC/MRG-1, at 48). The Department finds that the design of Scenario 3 too closely resembles existing geothermal networks, including a 7,500 single-family home community near Austin, Texas, and National Grid New York's geothermal demonstration project serving two residential communities in Long Island (Exhs. DPU-ES 2-24; AG-DDE-1, at 35, 41). To the extent appropriate, the Company should rely on existing information to assist in its own evaluations of the opportunities for operating a geothermal network. See 2016-2018 Three-Year Plans Order, at 143. Further, the Company must ensure that any proposed demonstration project is not duplicative of other projects either underway or proposed. D.P.U. 16-184, at 14. Accordingly, the Department is not convinced that the potential incremental benefits, in terms of lessons learned from serving an all residential neighborhood, from Scenario 3 will outweigh the costs to ratepayers. In addition, the Department is not convinced that other insights to be learned from Scenario 3 are substantially different from those generated from Scenario 2 given that both include building through public ways, building across distances between structures, and acquiring potential easements or permits to access required land (Exh. ES-PMC/MRG-1, at 48). As such, NSTAR Gas's proposal to recover costs associated with Scenario 3 is denied.[72]

v. Backup Heat Source

HEET suggests that the Company modify its proposal to include one single heater and cooler on each shared loop, as opposed to installing individual heaters and coolers for each unit associated with the loop as backup (HEET Brief at 28-29, citing Exhs. DPU-ES 9-14; DPU-ES 20-11).[73] The Company argues that it is not appropriate to have a single backup heat source on the shared loop because, where the single backup heat pump motor fails, all customers will be affected (Company Brief at 464). After review, the Department declines to adopt modifications to the design of the backup heating system. The Department finds that the Company's proposed approach to provide each participant in the demonstration project with a backup heating system is reasonable and appropriate. Given that the purpose of the demonstration project is to test the operation and reliability of a shared geothermal loop, the Department finds that the Company's proposed approach balances the costs and potential risk to participants. Further, there is no record evidence to support whether HEET's proposal will provide the same benefits.

72 As with Scenario 1, since the Department has denied Scenario 3, we will not address HEET's recommendation to implement a phased approach with Scenario 3.

73 HEET argues that a common backup heater will reduce the potential need to add glycol to the loop, which could reduce the Company's projected costs by over $300,000 (HEET Brief at 29, citing Exh. DPU-ES 20-9).

vi. Inclusion of Gas Customers

The Company maintains that, although it does not intend to enroll existing gas customers in the demonstration project, there are direct benefits to ratepayers (Exhs. DPU-ES 9-5; DPU-ES 9-15; AG 32-2; AG 32-4). The Company explains that it is not yet able to quantify the value generated by the geothermal demonstration to existing gas customers, and that conducting the demonstration project will allow it to collect such data. For example, the Company argues that geothermal networks, if scaled, could generate net benefits to all customers by increasing the customer base over which fixed costs are spread (Exhs. DPU-ES 9-5; DPU-ES 9-15; AG 32-2; AG 32-4).[74]

While the Department finds that the demonstration project is designed to provide lessons learned that could benefit ratepayers, the Department shares the Attorney General's concerns that the costs associated with the demonstration project are proposed to be recovered entirely from the Company's gas customers despite the fact that these existing customers will not necessarily be participating in the project (Exh. AG-DDE-1, at 31).

The Department notes that the feasibility study conducted by HEET (and referenced by the Company in developing its proposal) focused on the potential of networked GSHPs to replace aging gas infrastructure and to reduce future GSEP investments (Exhs. DPU-ES 9-23,

[74] The Company also estimates that the benefits from reduced carbon emissions will accrue to all Massachusetts residents, including its gas customers (Exhs. DPU-ES 2-20; DPU-ES 9-15; AG-32-2(b)). The Department notes, however, that while reduction of GHG emissions is in line with the Commonwealth's overall environmental policies, such reductions are societal benefits and accrue generally to all residents of the Commonwealth rather than provide direct benefits to the Company's ratepayers.

Att. (a); DPU-ES 2-31(f)).[75] The Company's proposal, however, does not incorporate any study of replacing aging pipes with geothermal technology. The Company maintains that it would not be feasible to target aging, leak-prone pipes for the purposes of the demonstration project because the Company's main-replacement projects lie within existing areas of the distribution system and cannot be replaced randomly without causing disruptions in operations, nor does the Company have the discretion to forego such replacement (Exh. DPU-ES 31-10, citing G.L. c. 164, § 145).

However, the Company also stated that there would be no specific logistical obstacles to allowing existing gas customers to participate in the demonstration and to maintain their gas infrastructure for backup heating76 (Tr. 1, at 69-71). Although there may be some challenges to targeting existing gas customers for the purposes of the demonstration project, we encourage the Company to consider how to incorporate existing gas customers in the demonstration project. The Department reminds the Company that, although we approve the demonstration project, when the Company seeks cost recovery it bears the burden to demonstrate that the demonstration project is being implemented in a manner to provide

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75 HEET describes the GeoMicroDistrict as a system of ground source heat pumps shared by buildings along the same street segment where, as gas pipes are replaced, could interconnect to form a larger, more efficient system managed by a thermal distribution utility (Exh. DPU-ES 9-23, Att.(a), at 3).

76 The Company also stated that it would be more technically feasible to leave a customer's existing natural gas infrastructure in place in addition to the GSHP, rather than create a natural gas-powered communal backup heater for the entire loop (Tr. 1, at 52-53).

direct benefits to ratepayers whether through participation or in a manner that will generate findings to inform the scalability of networked geothermal for its existing gas customers.

d. Evaluation Plans

The Company has provided a detailed set of research questions that it seeks to study and data that it seeks to gather through the demonstration project (Exh. ES-PMC/MRG-1, at 53-57). NSTAR Gas intends to contract with a third-party evaluation firm to independently review the progress and results of the demonstration project (Exh. ES-PMC/MRG-1, at 53-57). The Company plans to file annual reports on the status of the geothermal demonstration project (Exh. ES-PMC/MRG-1, at 57). The Department has reviewed and accepts the Company's proposed evaluation plan, research questions, and data points. In order to monitor the progress and costs of the evaluation, the Department directs the Company to provide in its first annual report copies of RFPs for the evaluation consultant, submitted proposals, any agreements, and the scope of work, including any proposed performance metrics for the demonstration project.

e. Budget and Cost Recovery

i. Budget

The Company's updated cost estimates for Scenario 2 and the third-party evaluation plant were $10,261,606 and $300,000, respectively (Exh. DPU-ES 31-11, Att.). The Department notes that the proposed budget is an estimate and that the Company plans to recover the full actual costs of the demonstration project through the LDAC (Exh. ES-WJA/DPH-1, at 90). After review and consideration of the size, scale, and scope of the demonstration project, the Department finds that the initial budget estimate for

Scenario 2 is reasonable. As noted below, the Company as part of its annual reconciliation filing must demonstrate the prudency of all expenditures.

ii. Tariff Modifications

The Company proposed to recover the costs of the demand response and geothermal demonstration projects through the Y factor in the LDAC, amortized over the proposed five-year PBR term and reconciled against actual costs annually (proposed M.D.P.U. No. 402S, § 11; Exh. ES-WJA/DPH-1, at 90). In light of the Department's directives above, however, the Company's proposed recovery timeline for the geothermal demonstration project no longer aligns with the PBR term. Accordingly, the Department finds that it is appropriate for the Company to remove all references to the demonstration projects from the proposed PBR tariff, M.D.P.U. No. 411. The Department directs the Company to file a revised PBR tariff that excludes all references to the demonstration projects, including in sections four, ten, and eleven.

Further, since the Department has denied recovery of the gas demand response demonstration project, we find that it is appropriate for NSTAR Gas to modify its LDAC tariff as part of its compliance filing in this proceeding. NSTAR Gas shall include a Geothermal Energy Provision ("GEP") in the LDAC tariff that includes the language from proposed M.D.P.U. No. 411 that pertains to the geothermal demonstration project and is consistent with the directives contained in this Order, except all references to the Y factor shall be revised to refer to the "GEP Factor." The Department directs the Company to revise its proposed tariff language to reflect the directives in this Order regarding both the demand response and geothermal demonstration projects.

The Department directs the Company to include tariff language requiring the following: (1) actual GEP expenses incurred during the prior calendar year; and (2) a reconciliation component in the second year and beyond to true-up revenues collected through the GEP during prior years. Further, the GEP shall include language providing that interest on over- or under-recovery of the costs shall be calculated on the average monthly balance using the prime rate, as reported by the Wall Street Journal, consistent with the Company's LDAC tariff. The Company shall submit the GEP cost recovery filing as a separate docketed matter no later than August 1st each year, and include testimony and supporting exhibits, including documentation supporting all expenses.

iii. <u>Costs Eligible for Recovery</u>

Only geothermal demonstration project costs are eligible for cost recovery through the GEP Factor. With respect to O&M expenses, NSTAR Gas must demonstrate that all O&M expenses proposed for recovery through the GEP Factor are (1) incremental to the representative level of O&M expenses recovered through base distribution rates and (2) solely attributable to preauthorized geothermal demonstration project expenses. D.P.U. 17-13, at 62.

As is the case with any costs to be recovered from ratepayers, all geothermal demonstration project expenditures must be prudently incurred to be eligible for targeted cost recovery. The Department's standard of review on prudence involves a determination of whether a company's actions, based on all that it knew or should have known at that time, were reasonable and prudent in light of the existing circumstances. Attorney General v. Department of Public Utilities, 390 Mass. 208, 229 (1983). Department preauthorization of the geothermal demonstration project means that the Department will not revisit the prudence of the Companies' decision to proceed with those categories of investments. The Department will, however, review the prudence of NSTAR Gas's implementation of these investments. D.P.U. 15-120/D.P.U. 15-121/D.P.U. 15-122, at 220. As part of this review, the Company must demonstrate that any non-ratepayer funding eligible for use on the geothermal demonstration project is used to offset the estimated cost of the project. Further, consistent with the geothermal demonstration project's purpose to advance knowledge in the field, NSTAR Gas must demonstrate that it coordinated with the Attorney General to ensure that the data and insight gathered from the geothermal demonstration project will be sufficiently distinct from the geothermal network that will be developed in the Greater Lawrence area. D.P.U. 20-59, Settlement Appendix 6, at 3. All costs recovered from ratepayers for any expenditures determined to be imprudent shall be refunded through the reconciliation component of the GEP Factor, with associated interest.

Moreover, the Department emphasizes the importance of the Company's developing and maintaining systematic, ample, and contemporaneous documentation of all geothermal demonstration project costs for which they seek targeted cost recovery. A failure to provide clear, cohesive, and reviewable evidence demonstrating eligibility will result in disallowance of targeted cost recovery of the expenditures in question. Massachusetts Electric Company, D.P.U. 95-40, at 7 (1995); Boston Gas Company, D.P.U. 93-60, at 26-27 (1993); The Berkshire Gas Company, D.P.U. 92-210, at 24 (1993). NSTAR Gas must submit contemporaneous project documentation and other evidence demonstrating that each of these conditions has been met. The Department will review the Company's submissions and disallow targeted cost recovery of all expenses where the proper showing has not been made.

Lastly, the Department directs the Company to attempt to find a third-party buyer/operator before coming before the Department to recover any decommissioning costs. The Department notes that it will review a request to recover decommissioning costs to the extent that: (1) they are prudently incurred; (2) the Company demonstrates that it has attempted to mitigate costs; and (3) the Company demonstrates that it has made a good faith effort to conduct the demonstration project to directly benefit gas ratepayers in terms of participation or scalability.

f. Other Issues

i. Stakeholder Input

The Company proposes to hold an annual stakeholder meeting to review the draft annual report described above and prior year's performance before the report is filed with the Department (Exh. DOER-ES 1-3). Ahead of the annual stakeholder meeting, the Company will distribute a draft annual report to stakeholders for review (Exh. DOER-ES 1-3). Stakeholders will be welcome to comment on the draft filing, including on next steps, and the Company will address input to the extent feasible (Exh. DOER-ES 1-3). Additionally, the Company commits to regular, if informal, communication with key stakeholders throughout the lifecycle of the demonstration project in order to solicit feedback (Exh. DOER-ES 1-3).

Each annual filing with the Department will include a section dedicated to describing the specific stakeholder outreach that was conducted, the input that was provided, and how that stakeholder input was, or was not, incorporated in the demonstration program
(Exh. ES-PMC/MRG-1, at 26).

The Department finds that the Company's plan to solicit stakeholder engagement and input is reasonable. The Department also recognizes the importance of making the information generated from the project available to any interested stakeholders and directs the Company to include the data required by DOE in its in annual report to the Department, regardless of whether the Company receives the grant. Further, the Department encourages the Company to engage with key stakeholders for their input on site selection at least once prior to commencing the project and to maintain regular communication with key stakeholders throughout the lifecycle of the project. Additionally, the Department encourages the Company to monitor HEET's "Community Charrettes" and to incorporate relevant feedback from experts in the geothermal industry and community groups where appropriate.

ii. Implementation Plan

As discussed above, NSTAR Gas has proposed an innovative demonstration project that could generate valuable insight into the effectiveness, viability, and scalability of geothermal networks in the Commonwealth. However, prior to the Company's enrollment of customers in the demonstration project, NSTAR Gas shall submit for Department review an implementation plan that addresses the below information.

While the Company has provided sufficient information regarding the general design of the demonstration project, the Department is concerned that the Company has not contemplated the terms and conditions, including consumer protections, for geothermal demonstration participants. Namely, the Company has not provided any terms of service including, but not limited to, the rights of the Company and participants with respect to notice, non-payment, late charges, fees, termination of service, in-home equipment damage or malfunction, access to the premises, maintenance obligations, loss or damage to the system, liability, system removal, and how participants will be affected in the event that the geothermal equipment needs to be decommissioned or sold to a third party. Therefore, the Department directs NSTAR Gas to submit standard terms of service to the Department as part of the implementation plan before it can begin to enroll customers in its geothermal demonstration project.

Further, consistent with the Department's directives above, the Department directs the Company to include a detailed description in the implementation plan of whether and how the Company plans to modify its demonstration project or its evaluation plan to include existing gas customers and address the potential assessment of scalability to existing gas customers. The Company must also submit an updated project budget and customer bill impacts after the site selection has been finalized that incorporates all the Department's directives and project modifications stated herein.

iii. Statewide Investigation

While the Attorney General is supportive of the project, she argues that the potential of geothermal should be considered in the context of a generic statewide proceeding to consider several threshold questions before authorizing a ratepayer-funded geothermal demonstration project conducted by a gas company (Attorney General Brief at 163; Attorney General Reply Brief at 55-56). For the reasons discussed above, the Department finds that approving the proposed demonstration project at this time is appropriate and, therefore, the Department declines to open a generic investigation for the purpose outlined by the Attorney General. The Department notes that its approval of the geothermal demonstration is subject to several modifications and directives that address many of the concerns that the Attorney General would explore in a generic proceeding. For example, the Department has reduced the bill impact to customers by eliminating redundancies and focusing on the geothermal network design with the most potential for scalability and benefit to ratepayers. Moreover, the data and insight obtained through this demonstration project will inform the Department's investigation in D.P.U. 20-80.

4. Conclusion

The Department considers the Company's proposal to be in line with the Commonwealth's aggressive climate goals. However, the Department directs the Company to limit its proposed demonstration to target the mixed-used urban neighborhood in Scenario 2. As outlined above, the Department considers Scenario 2 to have the potential to deliver the most value in relation to its costs. Additionally, the Department directs the Company to study the scalability of networked geothermal to serve the Company's existing natural gas customers. Subject to the directives set forth above and to the Company's submission of a detailed implementation plan, the Department approves the Company's proposed geothermal demonstration project for a dense, mixed-use neighborhood.

## VII. RATE BASE

### A. Introduction

NSTAR Gas's test-year end rate base was calculated as $781,230,669[77] (Exh. ES-DPH/ANB-2, Sch. 26). The Company proposed to adjust its test-year end rate base to include non-GSEP plant additions placed into service in 2019 and the associated accumulated amortization, depreciation, and deferred income taxes (Exhs. ES-LML/TCD-1, at 33; ES-LML/TCD-1 (Supp.) at 2; ES-LML/TCD-13; ES-DPH/ANB-2 (Rev. 3), Schs. 26, 27). Additionally, the Company proposes to include plant additions that were previously disallowed in D.P.U. 14-150 and NSTAR Gas Company, D.P.U. 16-GREC-06 (2016)[78] (Exhs. ES-LML/TCD-1, at 33; ES-LML/TCD-1 (Supp.) at 2; ES-LML/TCD-13; ES-DPH/ANB-2 (Rev. 3), Schs. 26, 27).

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77 The test-year-end rate base amount includes GSEP investments approved by the Department and recorded as in service through December 31, 2018, as well as capital additions previously disallowed in D.P.U. 14-150 and D.P.U. 16-GREC-06, as explained further below.

78 NSTAR Gas also proposes to adjust expense to account for the Auburn Area Work Center project and the Enterprise IT Projects, both of which the Company states were undertaken by ESC for the benefit of the Company and its customers (Exh. ES-LML/TCD-1, at 33). These capital projects are discussed in detail in Section VIII.C.F, below.

NSTAR Gas's total proposed rate base as of December 31, 2019, was $809,579,310, and consists of the following: (1) $1,540,706,444 in total utility plant in service; (2) $10,746,402 in cash working capital; and (3) $3,712,228 in materials and supplies; less (1) $470,952,330 of accumulated depreciation; (2) $3,832,489 in accumulated amortization; (3) $159,689,407 in deferred income taxes; (4) $107,529,032 in Financial Accounting Standard No. 109 ("FAS 109")[79] regulatory liability; (5) $1,260,770 in customer deposits; and (6) $2,321,737 in customer advances (Exh. ES-DPH/ANB-2 (Rev. 3), Schs. 1, at 4, 26).[80]

Further, as discussed above in Section V, the Company seeks approval of a proposed PBRM. NSTAR Gas proposed that in its first annual PBR mechanism filing for rates effective November 1, 2021, the Company will update the revenue requirement to include in rate base plant additions made in 2020, and the associated accumulated amortization, depreciation, and deferred income taxes (Exhs. ES-LML/TCD-1, at 58; ES-LML/TCD-1 (Supp.) at 1). The Company also proposed to retain the option of extending the PBRM for an additional five years beginning November 1, 2025, in conjunction with an update to rate base to include capital additions placed into service through December 31, 2024 (Exh. ES-WJA/DPH-1, at 99). Should the Department permit the extension of the PBRM

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79 FAS 109 requires companies to recognize on their financial statements all previously unrecorded future income tax liabilities. D.P.U. 14-150, at 143-144.

80 Minor discrepancies in any of the amounts appearing in this section are due to rounding.

and the rate base update, the Company would file the project documentation with the Department for review on or before April 1, 2025 (Exh. ES-WJA/DPH-1, at 99).

B. Test-Year-End Plant Additions

1. Introduction

As of December 31, 2018, NSTAR Gas had a utility plant in service balance of $1,477,221,069 (Exh. ES-DPH/ANB-2, Schs. 26, 28). The reserve for depreciation balance as of the same date was $446,838,649, yielding a net plant balance of $1,030,382,421 (Exh. ES-DPH/ANB-2, Schs. 26, 28). From January 1, 2015 through December 31, 2018, the Company placed into service $490,795,804 of plant additions (Exhs. ES-LML/TCD-2 (Rev.); ES-LML/TCD-3 (Rev.)).[81]

In NSTAR Gas Company, D.P.U. 14-135, at 143-144 (2015), the Department approved the Company's GSEP mechanism pursuant to G.L. c. 164, § 145.[82] In its initial filing, NSTAR Gas proposed to "roll-in" the revenue requirement associated with GSEP investments placed in service through December 31, 2019, including the associated taxes and depreciation expense, into rate base for recovery through base distribution rates ("GSEP

81 The additional plant investment placed into service for each year was $82,410,983 in 2015, $129,879,675 in 2016, $125,272,971 in 2017, and $153,232,175 in 2018 (Exh. ES-LML/TCD-3 (Rev.)).

82 The GSEP is designed to recover annually, on a reconciling basis, the revenue requirement (including a return on investment, property taxes, and depreciation on capital investments made after January 1, 2015) to replace or improve aging or leaking infrastructure, such as mains, services, meter sets, and other ancillary facilities composed of leak-prone material (e.g., non-cathodically protected steel, cast iron, and wrought iron). G.L. c. 164, § 145; D.P.U. 14-135, at 4, n.9; M.D.P.U. No. 402R, § 8.1.

roll-in") (Exh. ES-DPH/ANB-1, at 4, 8, 11, 128).[83] During the proceeding, the Company amended the GSEP roll-in proposal to include in rate base only the GSEP investments placed in service through December 31, 2018 (Exhs. ES-DPH/ANB-2 (Rev. 1), Schs. 26, 27; DPU-ES 7-3). Subject to the Department's approval of the GSEP roll-in, the Company also proposed to submit a revised gas system enhancement adjustment factor ("GSEAF") filing to effectuate a corresponding reduction to the GSEAF rate (Exh. DPU-ES 7-3). In addition, during the evidentiary hearings the Company proposed to exclude property tax expense for 2019 GSEP investments from the GSEP mechanism to avoid the potential for double-recovery of costs because the Company could not recalculate the pro forma adjustment in the instant proceeding to remove the property tax expense associated with the 2019 GSEP investments in the approved property tax expense (RR-AG-1).

The Company has provided documentation for approximately 1,459 non-GSEP capital projects placed into service from January 1, 2015 through December 31, 2018 and in excess of $50,000; the documentation includes the following: (1) cover sheets; (2) authorization documents, including approvals by management in accordance with the delegation of

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83 Since approval of the GSEP, NSTAR Gas has submitted ten fillings to support cost recovery of GSEP-eligible investments placed into service from 2015 through 2020. NSTAR Gas Company, D.P.U. 15-GSEP-06 (2016); NSTAR Gas Company, D.P.U. 16-GREC-06 (2016); NSTAR Gas Company, D.P.U. 16-GSEP-06 (2017); NSTAR Gas Company, D.P.U. 17-GREC-06 (2017); NSTAR Gas Company, D.P.U. 17-GSEP-06 (2018); NSTAR Gas Company, D.P.U. 18-GREC-06 (2018); NSTAR Gas Company, D.P.U. 18-GSEP-06 (2019); NSTAR Gas Company, D.P.U. 19-GREC-06 (2019); NSTAR Gas Company, D.P.U. 19-GSEP-06 (April 30, 2020); NSTAR Gas Company, D.P.U. 20-GREC-06 (October 30, 2020).

authority with supporting schedules; (3) closing reports; and (4) for revenue producing projects, a copy of the financial analysis calculating the pre-construction net present value of revenue requirements and pre-construction net present value of expected revenues (Exhs. ES-LML/TCD-1, at 28, 31; ES-LML/TCD-5). The Company also provided project documentation supporting the January 1, 2015 through December 31, 2018, GSEP investments (Exhs. ES-LML/TCD-1, at 29, 59-60; ES-LML/TCD-6).

2. Positions of the Parties

NSTAR Gas argues that the costs associated with the Company's plant additions from January 1, 2015 through December 31, 2018 were prudently incurred and that the plant is used and useful (Company Brief at 320). Further, the Company asserts that it has provided sufficient evidence to support the plant in service, including project cover sheets, approved amounts, actual costs, variance information and closure papers (Company Brief at 319). In particular, the Company contends that it has maintained detailed information for each specific project with direct costs greater than $100,000, including cover sheets, project authorization forms, closing reports by year and by project, and variance analyses demonstrating prudency (Company Brief at 328, 329). The Company also claims that, consistent with industry practice and Department precedent, it uses blanket authorizations to manage smaller projects with direct costs less than $100,000, which are typically emergent, unplanned work or annual blanket programs such as meter and tool purchases (Company Brief at 329).

NSTAR Gas contends that all capital projects are managed in accordance with the Company's capital authorization policy and include a multi-tiered management process to manage costs and establish budget parameters (Company Brief at 321). The Company notes that all capital projects are reviewed and approved by the plant accounting department to ensure proper capital and expense classification, project justification, and unit of property accounting (Company Brief at 324, citing Exh. ES-LML/TCD-1, at 16). Further, the Company provides that projects are authorized in accordance with the delegation of authority on the basis of a project authorization form and includes the project's description and objectives, scope and justification, financial evaluation, risk assessment, any alternatives considered, and a project schedule with milestones and an implementation plan (Company Brief at 324, citing Exh. ES-LML/TCD-1, at 16-17). In addition, the Company points out that a project manager and project originator are responsible for submitting supplementary authorizations when changes to the scope of a project will affect the cost of the project, subject to an established set of threshold requirements (Company Brief at 325, citing Exh. ES-LML/TCD-1, at 17). According to the Company, the foregoing process ensures control over costs on both ongoing and planned capital projects (Company Brief at 327). No party challenged the Company's proposed capital additions completed from January 1, 2015 through December 31, 2018, on brief.

3. Standard of Review

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 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, 229-230 (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 (1993); 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. Massachusetts Electric Company, D.P.U. 95-40, at 7 (1995); D.P.U. 93-60, at 26; D.P.U. 92-210, at 24; see also Massachusetts Electric Company v. Department of Public Utilities, 376 Mass. 294, 304 (1978); Metropolitan District Commission v. Department of Public Utilities, 352 Mass. 18, 24 (1967).[84] In addition, the Department has stated:

> In reviewing the investments in main extensions that were made without a cost-benefit analysis, the [c]ompany 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 [c]ompany must provide reviewable documentation for investments it seeks to include in rate base.

D.P.U. 92-210, at 24.

#### 4. Analysis and Findings

No party challenged the prudence of NSTAR's plant additions made from January 1, 2015 through December 31, 2018. Nevertheless, the Company bears the burden of demonstrating through clear and convincing evidence that such plant investments were prudently made. Massachusetts Electric Company, D.P.U. 95-40, at 7 (1995), citing Boston Gas Company, D.P.U. 93-60, at 26 (1993); Massachusetts Electric Company v. Department of Public Utilities, 376 Mass. 294, 304 (1978); Metropolitan District Commission v. Department of Public Utilities, 352 Mass. 18, 24 (1967). To demonstrate its cost control

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84 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. Boston Gas Company, D.T.E. 03-40, at 52 n.31 (2003), citing D.T.E. 01-56-A at 16; Fitchburg Gas and Electric Light Company, D.T.E. 99-118, at 7 (2001).

efforts, NSTAR Gas has provided information regarding its capital planning and authorization processes, including the Company's project authorization policies and documentation such as project authorization forms; work project estimates; project closure reports; variance analyses explaining cost overruns; and, for revenue producing projects, the pre- and post-construction financial analyses used to determine contributions in aid of construction ("CIACs") (Exhs. ES-LML/TCD-5, Schs. 5A-5E; ES-LML/TCD-6; ES-LML/TCD-12).

The Company has provided documentation on all projects, programs, and work orders that have total costs in excess of $50,000 (Exhs. ES-LML/TCD-1, at 23; ES-LML/TCD-1 (Supp.) at 3; ES-LML/TCD-5 (Rev.); ES-LML/TCD-6; ES-LML/TCD-8; ES-LML/TCD-10; ES-LML/TCD-13).[85] The documentation provided for each project includes a cover sheet, project authorization document; supporting schedules; a closing report detailing the charges to a project; and, for revenue producing projects, a financial analysis of the net present value of the projects revenue requirements and net present value of expected revenues (Exh. ES-LML/TCD-1, at 31). In addition to the project specific documentation described above, the Company has provided the in-service dates for all test-year-end capital projects included for recovery in rate base (Exhs. ES-LML/TCD-3 (Rev.), Schs. 3A, 3B, 3C, 3D; ES-LML/TCD-3 (Supp.), Schs. 3A, 3B, 3C, 3D; DPU-ES 17-15; DPU-ES 17-30).

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[85] The Company maintains the documentation for all capital projects, but due to the volume of documentation, has provided only the documentation for projects in excess of $50,000 (Exh. ES-LML/TCD-1, at 32-33).

The Department has reviewed the documentation supporting the non-GSEP plant additions made from January 1, 2015 through December 31, 2018, including the work project estimates, project authorization forms, financial analyses, and closing reports. The Department finds that the project costs were prudently incurred. In addition, the projects are found to be used and useful in providing service to ratepayers. As such, the Department allows these investments in the Company's plant in service.

Pursuant to the Company's LDAC tariff, NSTAR Gas seeks to incorporate into rate base the GSEP-related investments made from January 1, 2015 through December 31, 2018 (Exh. ES-LML/TCD-1, at 57-60; M.D.P.U. No. 402R § 8.9.3). The Company has included the supporting documentation previously reviewed in the Company's GREC filings (Exhs. ES LML/TCD-1, at 7, 29, 59-60; ES-LML/TCD-6). From January 1, 2015 through December 31, 2018, the Company invested $244,508,728 in GSEP projects (Exh. ES-LML/TCD-2 (Rev.)). The Department reviewed the investments in the Company's annual GREC filings, D.P.U. 16-GREC-06, D.P.U. 17-GREC-06, D.P.U. 18-GREC-06, and D.P.U. 19-GREC-06. With the exception of certain projects originally filed in D.P.U. 16-GREC-06, which are discussed in further detail below, the Department previously found the GSEP capital additions to be prudently incurred and used and useful in providing service to ratepayers. D.P.U. 19-GREC-06, at 19-20; D.P.U. 18-GREC-06, at 23-24; D.P.U. 17-GREC-06, at 35-36; D.P.U. 16-GREC-06, at 20-24. Accordingly, the Department allows the inclusion of these investments in the Company's plant in service.

In D.P.U. 18-GSEP-06, the Department directed NSTAR Gas to remove the revenue requirement constituting double recovery from the GSEAF concurrent with new base distribution rates in future GSEP roll-in procedures not effective January 1st of a given year. NSTAR Gas Company, D.P.U. 18-GSEP-06, at 50; M.D.P.U. No. 402R, § 8.9.3. To ensure there is no overcollection of GSEP investments through the GSEP factors and base distribution rates, NSTAR Gas shall make the appropriate compliance filings in both this proceeding and the relevant GSEP proceedings (Exh. DPU-ES 7-3, at 4). The compliance filings shall include a revised GSEAF filing in D.P.U. 19-GSEP-06 to reduce the GSEAF rate to coincide with base distribution rates to be implemented on November 1, 2020 (Exh. DPU-ES 7-3, at 5 & Att.(a), at 1). In addition, the Department finds that the Company's proposal to exclude property tax expense related to the 2019 GSEP investments from the GSEP mechanism is appropriate (Tr. 2, at 216-219; Tr. 8, 1094-1095, 1105-1122; RR-AG-1). The Department directs the Company to demonstrate that it has excluded property tax expense related to the 2019 GSEP investments in the relevant GSEP proceedings.

## C. Post-Test-Year Plant Additions

### 1. Introduction

From January 1, 2019 through December 31, 2019, the Company placed into service \$176,631,116 of plant additions, of which it proposes to include \$78,605,947 (i.e., the portion unrelated to GSEP) in the revenue requirement calculations for an adjusted gross plant balance of \$1,540,706,444 (Exhs. ES-LML/TCD-2 (Supp.); ES-LML/TCD-3 (Supp.); ES-LML/TCD-13; ES-DPH/ANB-2 (Rev. 3), Sch. 27). Further, as noted above, NSTAR

Gas proposed that in its first annual PBR filing for rates effective November 1, 2021, the Company will update the revenue requirement to include in rate base plant additions placed in service in 2020 (Exhs. ES-LML/TCD-1, at 58; ES-LML/TCD-1 (Supp.) at 1).

2. Positions of the Parties

a. Attorney General

The Attorney General argues that NSTAR Gas's proposal to include in rate base 2019 plant additions is inconsistent with Department precedent, and she argues that the Company has failed to provide a basis to depart from such precedent (Attorney General Brief at 14, citing NSTAR Electric Company/Western Massachusetts Electric Company, D.P.U. 17-05, at 101 (2017); Boston Gas Company, D.P.U. 96-50-C at 16-18, 2021 (1997); Boston Gas Company, D.P.U. 96-50, at 15-16 (1996); Attorney General Reply Brief at 4). Specifically, the Attorney General contends that the Company neither claims nor can demonstrate that any of the post-test-year plant additions constitute a significant investment that would have a substantial impact on its rate base (Attorney General Brief at 14-15; Attorney General Reply Brief at 4). Rather, she notes that the vast majority of the Company's 2019 non-GSEP projects are in fact relatively small with an average cost of $16,992 per project (Attorney General Brief at 15, citing Exhs. AG-FWR-Surrebuttal-1, at 2; AG-FWR-Surrebutal-2). Further, the Attorney General asserts that 61 percent of the 2019 capital projects were revenue producing and that these projects substantially offset the revenue requirement on non-revenue-producing projects (Attorney General Brief at 17, citing Exhs. AG-FWR-Surrebuttal-1, at 3; AG-FWR-Surrebuttal-2; Attorney General Reply Brief at 5).[86] The Attorney General's objections to the inclusion of the 2019 plant additions in rate base regarding the PBR Plan are set forth in Section V.B.3 above.

b. Company

The Company contends that it has supported its proposal to include the 2019 non-GSEP capital additions in rate base with requisite project documentation (Company Brief at 49-50, citing Exhs. ES-LML/TCD-2 (Supp.); ES-LML/TCD-3 (Supp.); ES-LML/TCD-4 (Supp.); ES-LML/TCD-13). The Company asserts that the capital additions submitted for approval in this proceeding were prudently incurred and used and useful in providing service to customers (Company Brief at 320).

3. Standard of Review

The Department does not recognize post-test year additions or retirements to rate base, unless the utility demonstrates that the additions or retirements represent a significant investment which has a substantial effect on its rate base. Boston Gas Company, D.P.U. 96-50-C at 16-18, 20-21 (1997); D.P.U. 95-118, at 56, 86; D.P.U. 85-270, at 141 n.21. 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

[86] For example, the Attorney General notes that for revenue-producing projects with costs greater than $50,0000, the net present value on the expected revenue requirement is $5,187,623 while the net present value of expected revenues from the same projects is $9,019,452 (Attorney General Reply Brief at 5, citing Exh. ES-LML/TCD-4 (Supp. 1), Sch. 4B). Further, she points out that the Company's 2019 blanket projects had a net present value of expected revenue requirement of $2,227,996 compared to a net present value of expected revenues of $5,278,205 (Attorney General Reply Brief at 6, citing Exh. ES-LML/TCD-4 (Supp. 1), Sch. 4D).

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. 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).

4. Analysis and Findings

NSTAR Gas proposes to adjust its test-year end rate base to include non-GSEP plant additions placed into service in 2019 (Exhs. ES-LML/TCD-1, at 33; ES-LML/TCD-1 (Supp.) at 2; ES-LML/TCD-13; ES-DPH/ANB-2 (Rev. 3), Schs. 26, 27). For the reasons discussed in Section V.B.4.f.i, above, we have allowed NSTAR Gas to adjust rate base for non-GSEP plant additions placed in service in 2019 and associated accumulated amortization, depreciation, and deferred income tax as part of the first annual PBR adjustment to take effect November 1, 2021. In light of our findings above, we will not address whether the Company's 2019 plant additions represent a significant investment which has a substantial effect on its rate base.

To promote administrative efficiency, we determine it is appropriate to make findings on the prudence of the Company's 2019 non-GSEP investments in this proceeding. NSTAR Gas provided work project estimates, project authorization forms, financial analyses, and closing reports associated with its 2019 non-GSEP investments (Exh. ES-LML/TCD-13). Based on the record evidence, the costs associated with the 2019 non-GSEP projects are found to be known and measurable, prudently incurred, and used and useful to ratepayers.

The Department will not revisit the prudence of the 2019 non-GSEP investments when NSTAR Gas seeks to update rate base in the Company's first annual PBR adjustment filing.

D. Prior Disallowances

1. Introduction

In D.P.U. 14-150, at 93, the Department disallowed $6,108,401 in post-test-year project costs. Subsequently, the Company filed a motion for reconsideration seeking to recover disallowances totaling $5,802,035. D.P.U. 14-150, Motion for Reconsideration at 31-32. The Company broke down the $5,802,035 as follows: (1) $2,979,898 associated with 37 projects with costs exceeding $100,000; (2) $66,713 associated with a subdivision project, number 99816; (3) $101,748 associated with the difference between (a) $255,429 in costs disallowed by the Department for project numbers 99841 and 99843 and (b) $153,681 in costs that the Company concedes should have been disallowed; (4) $1,107,654 associated with service relay projects; and (5) $1,546,022 associated with prior-year-specific projects. D.P.U. 14-150, Motion for Reconsideration at 16, 19-20, 26, 28-29.

Today, the Department issued its Order on the Company's motion for reconsideration. The Department granted the Company's motion for reconsideration associated with the projects that did not have CIAC costs netted out of the gross plant additions, as explained in that Order and herein further below. D.P.U. 14-150-A at 19-20. The Department denied the Company's motion for reconsideration as to the remaining capital additions, based on the evidence presented in that proceeding. D.P.U. 14-150-A at 15-25. The Department concluded that while some of the remaining plant additions may have a reasonable basis for inclusion in rate base, NSTAR Gas had not made a satisfactory showing in that proceeding.

D.P.U. 14-150-A at 25. Further, we found that while contemporaneously prepared documentation of plant additions is less vulnerable to challenge than after-the-fact analysis, evidentiary shortcomings can be cured in future proceedings. D.P.U. 14-150-A at 25, citing Bay State Gas Company, D.T.E. 05-27, at 94 n.70 (2005); see also D.P.U. 08-27, at 32, 34.

In addition to the D.P.U. 14-150 cost disallowances that were subject to NSTAR Gas's motion for reconsideration, the Company also seeks to recover costs associated with a project for which a portion of the costs was to be reimbursed by the Massachusetts Department of Transportation ("DOT") (Exh. ES-LML/TCD-1, at 67). In D.P.U. 14-150, at 89, the Department disallowed recovery of the portion of the project costs for which the Company had not yet received reimbursement from the Massachusetts DOT. This issue was not raised in the Company's subsequent motion for reconsideration.

Finally, in D.P.U. 16-GREC-06, the Department disallowed recovery of certain plant additions associated with the Company's GSEP program. Specifically, the Department disallowed recovery associated with the following: (1) $7,719 for project number 234, work order 02110214, because the project did not constitute "eligible infrastructure" as required under G.L. c. 164, § 145 ("Section 145"); (2) $154,425 for copper services that did not constitute eligible infrastructure under either Section 145 or the Company's GSEP tariff; (3) $3,402,402 for five projects, number 57, 94, 95, 103 and 235, where the physical work on the project was completed prior to 2015 contrary to the requirements of Section 145(a); and (4) $1,299,662 for combined cost variances associated with multiple projects where the Company did not provide the requisite variance analyses. D.P.U. 16-GREC-06, at 9-12, 22-23; see also Fitchburg Gas and Electric Light Company et al., D.P.U. 16-GREC-01-A through D.P.U. 16-GREC-06-A at 26-28, 29-31, 34 (2017).

2. Positions of the Parties

a. Attorney General

The Attorney General argues that the Department should reject the Company's proposal to include plant that was previously disallowed in D.P.U. 14-150 (Attorney General Brief at 19; Attorney General Reply Brief at 8). She claims that the Company's proposal is an attempt to sidestep the pending motion for reconsideration in D.P.U. 14-150, and to relitigate the same arguments from its last base distribution rate case (Attorney General Brief at 19; Attorney General Reply Brief at 8-9). In this regard, the Attorney General contends that the Company's proposal is barred by the doctrine of issue preclusion or collateral estoppel (Attorney General Brief at 20). Further, the Attorney General notes that NSTAR Gas does not, and cannot, cite to any Department precedent to support its claim that if the Department were never to rule on the motion for reconsideration, the Company would never have the opportunity to recover costs associated with capital additions that are in service and benefitting customers, even if those costs were reasonably and prudently incurred (Attorney General Reply Brief at 9). The Attorney General asserts that the Department should neither consider the same evidence and arguments from D.P.U. 14-150 nor accept new evidence in support of the Company's position (Attorney General Brief at 21).

The Attorney General does not take a position regarding the Company's proposal to include plant investments previously disallowed in D.P.U. 16-GREC-06.

b. Company

The Company argues that it has provided the requisite documentation to support the inclusion of the costs associated with the capital additions that were disallowed in D.P.U. 14-150 (Company Brief at 346-347, citing Exhs. ES-LML/TCD-1, at 61-66; ES-LML/TCD-7; ES-LML/TCD-8). NSTAR Gas argues that there is nothing that precludes it from presenting evidence in the instant case to request recovery of the previously disallowed capital additions, particularly where the Company has supplemented the necessary documentation (Company Brief at 348). Further, the Company contends that it does not seek to introduce new evidence (Company Brief at 348). Rather, according to NSTAR Gas, the instant proceeding presents the best means by which the Company can provide the requisite documentation for the Department's review so that these projects can be included in rate base (Company Brief at 350). The Company asserts that if it is improperly denied a chance to include the costs associated with the D.P.U. 14-150 capital additions in rate base, it will never have the opportunity to earn a fair return on those investments and rates will not be set in a manner that allows for a fair return on the value of the investments that are being used to serve customers (Company Brief at 349).

Finally, with respect to the capital additions previously disallowed in D.P.U. 16-GREC-06, the Company argues that there is no basis for the Department to deny the inclusion of these projects in rate base (Company Brief at 347-348).

### 3. Analysis and Findings

#### a. D.P.U. 14-150 Disallowances

##### i. Introduction

The Department acknowledges the Attorney General's arguments regarding the propriety of revisiting the disallowances in D.P.U. 14-150. We find, however, that it is reasonable and appropriate to review the documentation provided in the instant proceeding to determine whether the Company has cured the evidentiary shortcomings that led to such disallowances. D.P.U. 14-150-A at 25, citing Bay State Gas Company, D.T.E. 05-27, at 94 n.70 (2005). We address each category of costs below.

##### ii. 37 Projects with Costs Exceeding $100,000

The Department first addresses the 37 projects with costs exceeding $100,000. In D.P.U. 14-150, at 90, the Department disallowed $641,710 in costs associated with four of the 37 projects – Project Nos. 13972, 13973, 13974 and 13978. The Department found that the total cost for each project exceeded $200,000 and each project had a cost variance greater than $25,000. D.P.U. 14-150, at 90 (internal citations omitted). Pursuant to the Company's capital authorization policy at that time, a project with direct costs in excess of $50,000 but less than $250,000, required a supplemental authorization if direct spending for projects exceeds the authorized level by $25,000. D.P.U. 14-150, at 90 (internal citations omitted). We determined that the Company failed to provide the requisite supplemental authorization, and the Department was unable to discern from the documentation provided that cost variances associated with these projects were prudently incurred. D.P.U. 14-150, at 90 (internal citations omitted). The Department affirmed this decision in D.P.U. 14-150-A at 16-18.

In the instant proceeding, the Company has provided documentation regarding these four projects, including the final cost for each project (Exh. ES-TCD/LML-8A at 2-79). The Department has reviewed the documentation, and we find that the Company still has failed to provide a sufficient explanation of cost variances for these four projects (Exh. ES-TCD/LML-8, Sch. 8A at 2-79). Therefore, the Department still is unable to make a determination that the cost variances associated with these projects were prudently incurred. D.P.U. 14-150, at 90.

The Company has provided documentation that shows the final actual costs of these four projects, including updated variance amounts (Exh. ES-TCD/LML-7, Sch. 7A). The Department disallows recovery of the variances above the estimated cost for each project, which total $685,266[87] (Exh. ES-TCD/LML-7, Sch. 7A; Sch. 8A at 2, 4, 21, 24, 43, 46, 63, 66). Accordingly, the Department reduces the Company's proposed plant in service by $685,266.

In D.P.U. 14-150, at 85, the Department analyzed project 99965, work order 1807922, and project 99967, work order 2007444, both of which incurred total costs exceeding $100,000, with project cost variances exceeding $25,000. The Department

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[87] Of this total, $147,170 was associated with project 13972; $164,411 was associated with project 13973; $256,641 was associated with project 13974; and $117,044 was associated with project 13978 (Exh. ES-TCD/LML-7, Sch. 7A; Sch. 8A at 2, 4, 21, 24, 43, 46, 63, 66).

determined that NSTAR Gas failed to provide sufficient evidence to support the cost variance for these two projects, and we reduced the Company's plant in service by a total of $66,394. D.P.U. 14-150, at 85-86. The Department affirmed this decision in D.P.U. 14-150-A at 16-18.

In the instant proceeding, the Company has provided work project estimates, project approval routing lists, and capital authorization analyses that include variance explanations (Exh. ES-TCD/LML-8, Sch. 8A at 80-115). The Department finds that the documentation is sufficient to support the prudency of the cost variances associated with these projects. Therefore, we conclude that the Company has cured the evidentiary shortcomings that resulted in a disallowance of the costs associated with these projects in D.P.U. 14-150. D.P.U. 14-150-A at 25, citing D.T.E. 05-27, at 94 n.70. Accordingly, the Department allows the cost variances associated with these two projects to be included in the Company's plant in service.

As we noted in D.P.U. 14-150, at 88, the remaining 31 projects were blanket projects exceeding $100,000 in costs, with cost overruns greater than 30 percent. D.P.U. 14-150, at 87, 88 (internal citations omitted). The Department determined that the Company failed to document the cost variances associated with these 31 blanket projects. D.P.U. 14-150, at 88-89. Thus, the Department reduced the Company's plant is service by the cost variances of these 31 blanket projects, for a total of $2,271,794. D.P.U. 14-150, at 89. The Department affirmed this decision in D.P.U. 14-150-A at 16-18.

In the instant proceeding, the Company submitted documentation for the 31 blanket projects for which cost overruns were disallowed in D.P.U. 14-150 (Exhs. ES-LML/TCD-1, at 68; ES-LML/TCD-8, Sch. 8D at 414-931). The documentation includes sufficient variance analyses to support the prudency of the cost variances for these projects (Exhs. ES-LML/TCD-7, Sch. 7D; ES-LML/TCD-8, Sch. 8D at 415-931). Therefore, the Department finds that the Company has cured the evidentiary shortcomings that resulted in a disallowance of the cost associated with these 31 blanket projects in D.P.U. 14-150. D.P.U. 14-150-A at 25, citing D.T.E. 05-27, at 94 n.70. Accordingly, the Department allows the cost variances associated with these 31 blanket projects to be included in the Company's plant in service.

iii. Sub-Division Project

In D.P.U. 14-150, at 84, the Department reviewed the documentation for project 99816, work order 1989745, a sub-division project. The Department determined that the Company did not provide a cost estimate for this revenue-producing project, nor did it perform a pre- and post-construction return or cost-benefit analysis. D.P.U. 14-150, at 84 (internal citations omitted). Therefore, the Department concluded that the Company failed to demonstrate the prudence of project 99816, work order 1989745, and reduced the Company's plant in service by the total cost of this project, $66,713. D.P.U. 14-150, at 84. The Department affirmed this decision in D.P.U. 14-150-A at 18-19.

In the instant proceeding, the Company provides documentation that it claims is sufficient to warrant recovery of the disallowed costs (Exhs. ES-LML/TCD-1, at 67-68;

ES-LML/TCD-7, Sch. 7B; ES-LML/TCD-8, Sch. 8B at 152-241). The Department has reviewed the documentation, and we find that it is insufficient to establish the prudency of this particular project. As the Department noted in D.P.U. 14-150-A at 18, project 99816, work order 1989745, was a sequential phase of another project identified as project 07839. The documentation provided by the Company indicates that "no work project estimate was done on this work order" (Exh. ES-LML/TCD-8, Sch 8B at 217). In addition, the original documentation for project 07839 states that, "a second phase [i.e., project 99816] is proposed for 6-8 additional buildings in the future. None of these buildings were used for the revenue calculation and may also need additional system improvements to support the loads" (Exh. ES-LML/TCD-8, Sch 8B at 173). Therefore, because the costs and revenues of this phase of the project were not considered in the initial authorization, and the Company did not perform a work project estimate on this phase, the Department cannot make a finding on the prudency of the investment. The documents provided by the Company show that the final costs associated with project 99816, work order 1989745, amount to $66,999 (Exh. ES-LML/TCD-8, Sch. 8B at 153). Accordingly, the Department reduces the Company's proposed plant in service by $66,999.

iv. Contributions in Aid of Construction

In D.P.U. 14-150, at 84-85, the Department disallowed $261,429, comprised of the following: (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. Upon reconsideration, the Department determined that only $153,681, equal to the CIAC collected from each customer on the projects, should have been disallowed. D.P.U. 14-150-A at 19. As such, the Department allowed recovery of $107,748. D.P.U. 14-150-A at 19-20. Accordingly, the Department allows $107,748 associated with these projects in the Company's plant in service. D.P.U. 14-150-A at 20.

v. Service Relay Projects

In D.P.U. 14-150, at 87, the Department analyzed seven service relay projects, each with actual costs in excess of $100,000, associated with main replacement projects. The Department found that NSTAR Gas did not provide cost estimates for these seven projects, as the Company explained that pursuant to capital project authorization policy existing at the time, cost estimates were developed for main relay projects, but not the associated service relay projects. D.P.U. 14-150, at 87 (internal citations omitted). The Department determined that a company's internal project cost estimation policies cannot override the company's obligation to demonstrate to the Department the prudence of its capital project costs. D.P.U. 14-150, at 87. Further, we found that 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. D.P.U. 14-150, at 87. Therefore, the Department concluded that the Company failed to demonstrate the prudence of the service relay projects, and we reduced the Company's plant in service by $1,107,654. D.P.U. 14-150, at 87. The Department affirmed this decision in D.P.U. 14-150-A at 20-22, and noted that the Company had not pointed to any evidence, such as cost estimates, supplemental authorizations, or variance explanations, that explains why these projects were estimated to be less than $100,000 but actually exceeded $100,000.

In the instant proceeding, the Company has resubmitted the project documentation from D.P.U. 14-150, along with additional project documentation (Exh. ES-TCD/LML-8, Sch. 8C at 243-413). The documentation still omits pre-construction estimates. For each of the seven service relay projects, however, the Company has provided sufficient documentation to explain that each project was approved under a blanket authorization, but for specific reasons the actual costs for each project exceeded $100,000 (see, e.g., Exhs. ES-LML/TCD-8, Sch. 8C at 244, 261, 279, 307, 325, 361, 389). Upon review of this documentation, the Department now is satisfied that the costs associated with these projects were prudently incurred and that the projects are used and useful in providing service to ratepayers. Therefore, the Department finds that the Company has cured the evidentiary shortcomings that resulted in a disallowance of the cost associated with these seven service relay projects in D.P.U. 14-150. D.P.U. 14-150-A at 25, citing D.T.E. 05-27, at 94 n.70. Accordingly, the Department allows the costs associated with these projects to be included in the Company's plant in service.

vi. Prior Year Specifics

In D.P.U. 14-150, at 93, the Department disallowed $1,546,022 in costs booked in 2014 associated with 40 projects closed to plant accounts in prior years. The Department determined that it was unable to determine the prudence of the additional costs associated with prior year specific projects because the record lacked project documentation to support these costs. D.P.U. 14-150, at 93. The Department affirmed this decision in D.P.U. 14-150-A at 22-24.

In the instant proceeding, the Company has provided project documentation for the 40 projects, including capital authorization forms, work project estimates, itemized costs, supplemental authorizations, closing reports, and, where appropriate, financial analyses of the projects (Exhs. ES-LML-TCD-7, Schs. 7F-7I; ES-LML/TCD-8, Schs. 8F-8I). The Department finds that this documentation is sufficient to support the prudency of the costs associated with these projects and booked in 2014 (Exh. ES-LML/TCD-8, Schs. 8F-8I). Therefore, the Company has cured the evidentiary shortcomings that resulted in a disallowance of the costs associated with these projects in D.P.U. 14-150. D.P.U. 14-150-A at 25, citing D.T.E. 05-27, at 94 n.70. Accordingly, the Department allows the costs associated with these projects and booked in 2014 to be included in the Company's plant in service.

#### vii. Massachusetts DOT Reimbursement

In D.P.U. 14-150, at 89, the Department found that NSTAR Gas had incurred $293,367 for project 12809, for which 50 percent of the costs would be reimbursed to the Company by the Massachusetts DOT. At the time, the Company had not yet received the reimbursement and, therefore, the Department determined that it was inappropriate for the Company to include $146,684 in costs that had not yet been reimbursed by Massachusetts DOT for project 12809. D.P.U. 14-150, at 89-90, citing Fitchburg Gas and Electric Light

Company, D.P.U. 13-90, at 140 (2014). Thus, the Department reduced the Company's plant in service by $146,684. D.P.U. 14-150, at 90.

In the instant proceeding, the Company has provided updated cost documentation for this project, which shows that the Massachusetts DOT reimbursed the Company a total of $55,515 (Exhs. ES-LML/TCD-1, at 67; ES-LML/TCD-8, Sch. 8A at 116; see also Tr. 6, at 878). Further, the Company notes that it intends to seek recovery of the remaining portion of the reimbursement, which would amount to $91,169 (Exh. ES-LML/TCD-8, Sch. 8A at 116; Tr. 6, at 879-880). Therefore, the Department finds that the proposed inclusion in rate base of $91,169 in costs that will be reimbursed by the Massachusetts DOT is inappropriate. D.P.U. 14-150, at 89, citing D.P.U. 13-90 at 140. Accordingly, the Department reduces the Company's proposed plant in service by $91,169.

b. D.P.U. 16-GREC-06 Disallowances

In the instant proceeding, the Company has provided updated supporting documentation for the 38 projects disallowed in the 2016 GREC filing (Exhs. ES-LML/TCD-5, Sch. 5A; ES-LML-TCD-9; ES-LML/TCD-10). The Department has reviewed the documentation provided. With respect to the first three categories identified in Section VII.D.1, above, the projects were disallowed in D.P.U. 16-GREC-06, because they failed to meet the infrastructure eligibility or replacement period requirement of the GSEP. D.P.U. 16-GREC-06, at 10, 11, 13-14. Under traditional ratemaking principles, however, NSTAR Gas may seek to include these capital additions in rate base in the instant case. D.P.U. 16-GREC-06, at 11, 14 n.11. Based on our review of the supporting documentation, we find that the costs associated with these projects were prudently incurred and that the projects are used and useful in providing service to ratepayers (Exhs. ES-LML/TCD-5, Sch. 5A; ES-LML/TCD-10). Accordingly, the Department allows the costs of these projects in the Company's plant in service.

Regarding the remaining projects, the Department found that the Company failed to demonstrate that the project costs beyond the original authorized estimates were prudently incurred. D.P.U. 16-GREC-06, at 22. In the instant proceeding, the Company has provided additional documentation for each of these projects sufficient to support the prudency of the cost variances associated with these projects (Exhs. ES-LML/TCD-5, Sch. 5A at 428; ES-LML/TCD-10). Accordingly, the Department allows the cost variances associated with these projects to be included in the Company's plant in service.

## E. 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.

2. Company's Lead-Lag Study

NSTAR Gas's lead-lag study measures the difference in time frames between revenue lag and expense lead (Exhs. ES-DPH/ANB-1, at 150; ES-DPH/ANB-5, at 4). The difference is expressed in terms of days and then divided by the total days in a year to produce the percentage of cash working capital included in rate base (Exhs. ES-DPH/ANB-1, at 150; ES-DPH/ANB-5, at 1, 4). The Company proposed a cash working capital of $10,746,402 based on the net lag factor of 9.43 percent, or 34.41 days (Exhs. ES-DPH/ANB-1, at 150; ES-DPH/ANB-2 (Rev. 3), Sch. 1, at 6). The Company also analyzed purchased gas working capital collected through the cost of gas adjustment clause ("CGAC") (Exh. ES-DPH/ANB-5, App. B). The purchased gas analysis resulted in a net lag factor of 2.98 percent, or 10.86 days.

a. O&M Cash Working Capital

For O&M cash working capital, the Company determined the revenue lag of 48.58 days by the sum of meter reading lag, billing lag, and collection lag (Exh. ES-DPH/ANB-5, at 5). The meter reading lag is the measure between the midpoint of service provided and the meter read (Exh. ES-DPH/ANB-5, at 5). The Company reads meters monthly, therefore, the meter reading lag of 15.21 days is derived from dividing 365 days in a year by twelve months, times one-half (Exh. ES-DPH/ANB-5, at 5). The billing lag measures from the midpoint of meter reading date to the date the customers are billed (Exh. ES-DPH/ANB-5, at 5). Considering weekends and holidays, the Company calculated the total billing lag of 1.45 days (Exh. ES-DPH/ANB-5, at 5). The collection lag measures the period from the billing date to the time the customer pays the bill (Exh. ES-DPH/ANB-5, at 5). It was calculated by dividing average daily accounts receivable by average daily sales to arrive at 31.92 days (Exh. ES-DPH/ANB-5, at 6).

To determine the expense lead for the O&M expense working capital, NSTAR Gas disaggregated the test-year, non-gas O&M expense into the following expense categories: (1) compensation; (2) employee benefits costs; (3) insurance expense and injuries and damages; (4) rate case expense; (5) uncollectible; (6) other O&M sampled; (7) depreciation and amortization; (8) taxes other than income taxes; (9) income taxes; and (10) distribution operating income (Exh. ES-DPH/ANB-5, at 7). Next, it reviewed the payments and calculated the lead days for each category, excluding uncollectible, depreciation and amortization, income taxes, and distribution operating income (Exh. ES-DPH/ANB-5, at 7-11). Finally, it used the sum of the lead days in each category weighted by dollars to arrive at the expense lead of 14.17 days (Exh. ES-DPH/ANB-5, at 14-15). The result of the revenue lag days and expense lead days produced the net lag days of 34.41 days, or 9.43 percent by dividing the net lag days by 365 days (Exh. ES-DPH/ANB-5, at 12).

b. Purchased Gas Cash Working Capital

To determine the purchased gas cash working capital, the Company analyzed the purchased gas expense lead by reviewing a listing of all purchased gas invoices paid in the test year (Exh. ES-DPH/ANB-5, at 16). The Company calculated the expense lead as the average time from the midpoint of the service period to the payment date and then weighted the outcome by total invoice amount to arrive at a total expense lead of 37.72 days

(Exh. ES-DPH/ANB-5, at 16). The result of the revenue lag of 48.58 days and the purchased gas expense lead of 37.72 days produced the net lag of 10.86 days, or 2.98 percent by dividing the net lag days by 365 days (Exhs. ES-DPH/ANB-5, at 16; ES-DPH/ANB-1, at 150).

3. Positions of the Parties

On brief, the Company summarized the calculation of its proposed cash working capital allowance (Company Brief at 151-152). The Company asserts that its cash working capital study is performed consistent with the Department's standard; therefore, its proposed cash working capital allowance should be adopted by the Department (Company Brief at 152). No other party commented on the Company's proposed cash working capital allowance on brief.

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. In the absence of a lead-lag study, the Department has previously relied on the 45-day convention as reasonably representative of O&M working capital requirements. D.T.E. 05-27, at 98; Boston Gas Company, D.P.U. 88-67 (Phase I) at 35 (1988).[88] The Department has expressed concern

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[88] When a fully developed and reliable lead-lag study is not available, the Federal Energy Regulatory Commission ("FERC") applies a 45-day convention to determine the cash working capital allowance. Carolina Power and Light Company, 6 FERC ¶ 61,154, at 61,296 (1979). As a result, companies occasionally refer to the 45-day convention as the FERC convention. D.P.U. 11-01/D.P.U. 11-02, at 150 n.81.

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. E.g., D.P.U. 17-05, at 120; D.P.U. 15-155, at 144; D.P.U. 11-01/D.P.U. 11-02, at 163. 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. In the event that the lead-lag factor is not below 45 days, a company will face a high 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 37.72 days and the net lag for purchased gas of 10.86 days (Exhs. ES-DPH/ANB-5, at 16; ES-DPH/ANB-1, at 150; DPU-ES 4-6 & Att.). Further, we find that the Company properly calculated a total revenue lag of 48.58 days, an O&M expense lead of 14.17 days, and a resulting net O&M expense lag of 34.41 days (Exhs. ES-DPH/ANB-1, at 150; ES-DPH/ANB-5, at 5-12; DPU-ES 4-1 & Atts.; DPU-ES 4-3 & Att.; DPU-ES 4-4 & Att.; DPU-ES 4-5 & Att.). The Company's proposed lead-lag factor of 34.41 days is lower than the Department's 45-day convention (Exhs. ES-DPH/ANB-1, at 150; ES-DPH/ANB-5, at 12-13; DPU-ES 4-5 & Att.). For these reasons, the Department accepts the Company's lead-lag study.

Application of the cash working capital factor of 9.43 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 $10,735,880 for the Company. The derivation of this cash working capital allowance is provided in Schedule 6 of this Order.

F. Contributions in Aid of Construction

1. Introduction

CIACs are defined as "donations or contributions in cash, services, or property from states, municipalities or other governmental agencies, individuals, and others for construction purposes." 220 CMR 50.00, Uniform System of Accounts for Gas Companies ("USOA-Gas"), Balance Sheet Accounts, Account 271. Initially, NSTAR Gas stated that it received $6,722,599 in CIACs from its customers for the years 2005 through 2018 (Exh. DPU-ES 18-4). The Company stated that the test year-end utility plant in service balance was reduced by $4,993,538, which comprised the $6,722,599 of CIACs received from customers less $1,729,061 of amortization (Exhs. DPU-ES 12-24(b); DPU-ES 18-4(a), (b); Tr. 8, at 1062). During the evidentiary hearings, however, NSTAR Gas stated that it actually received $6,822,508 in CIACs for the years 2005 through 2018 and provided a note with its revised calculation that the $99,909 discrepancy was mainly attributable to a change in the reimbursement type of some work orders (RR-DPU-18).

To ensure uniform accounting treatment among all gas companies, in D.P.U. 14-150 the Department directed NSTAR Gas to maintain CIAC as a separate account consistent with

220 CMR 50.00. D.P.U. 14-150, at 108-109. During the proceedings, the Company acknowledged that it had not complied with the Department's directive in D.P.U. 14-150, at 108-109, to maintain CIAC as a separate account consistent with the USOA-Gas, on the basis that the Company filed a motion for reconsideration and clarification on November 19, 2015 (Exh. DPU-ES 4-7). Instead, the Company continued to book CIAC as a credit against the cost of construction included in Account 101, Utility Plant in Service (Exhs. DPU-ES 4-7; DPU-ES 12-25, Att. (a); DPU-ES 18-7, Att.).

As a solution, NSTAR Gas proposed to implement the CIAC accounting approach approved by the Department in Bay State Gas Company, D.P.U. 12-25 (2012) at the direction of the Department (Exhs. DPU-ES 4-7; DPU-ES 12-26). Under this approach, the Company proposed to create a new subaccount, which will offset CIAC that is currently included in the Company's plant in service accounts and that will allow the balance in Account 101, Utility Plant in Service, and Account 106, Construction Completed not Classified, to remain unchanged (Exh. DPU-ES 12-26, Att.). The offsetting credit to this new account will be Account 271 (Exh. DPU-ES 12-26, Att.). In addition, a new line will be added to the plant detail pages of the Company's Annual Return to the Department to provide the details of the new subaccount (Exh. DPU-ES 12-26 & Att.). No party addressed the adjustment to rate base for CIAC or the Company's accounting method for CIAC on brief.

2. Analysis and Findings

a. Adjustment to Rate Base for CIAC

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 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. Dedham Water Company, D.P.U. 84-32, at 18-20 (1984), citing Hingham Water Company, D.P.U. 1590, at 22-23 (1984).

As discussed above, the Company first claimed that $4,993,538 of CIAC was credited against the test-year-end plant in service balance, and thereby test-year-end rate base, representing $6,722,599 of CIACs received from customers less $1,729,061 of amortization for the years 2005 through 2018 (Exhs. DPU-ES 12-24(b); DPU-ES 18-4(a), (b); Tr. 8, at 1062). Thereafter, the Company purported to reconcile the discrepancy in the record between the amount of CIAC received by the Company and the amount of CIAC booked to plant in service and proposed a revised total of CIAC received from customers for the years 2005 through 2018 of $6,822,508, a difference of $99,909 (Exhs. DPU-ES 12-25, Atts. (b)-(g); DPU-ES 18-4; RR-DPU-18). The Company's calculation contains a flaw, however, due to a transposition of the total CIAC received between 2005 and 2014, i.e., \$4,634,529 transposed to \$4,364,529 (Exhs. DPU-ES 12-25, Att. (b) at 27; RR-DPU-18, at 2).

Consequently, the Company's calculation of test-year-end CIAC understates the amount of CIAC received from customers (Exhs. DPU-ES 12-25, Att. (b) at 27; RR-DPU-18, at 2). Moreover, though the Company insists that the full amount of CIACs collected would be applied against its plant in service balance, the Company was unable to provide a clear and cohesive explanation on the record as to why the total amount of CIACs received by the Company differs from the amount booked to its plant accounts (Exhs. DPU-ES 12-25, Att. (b)-(g); DPU-ES 18-4; RR-DPU-18, at 2; Tr. 6, at 886-889; Tr. 8, at 1058-1061).

To review and understand the Company's accounting practices for CIACs, the Department was required to issue several rounds of discovery and devote a significant amount of time during evidentiary hearings, and the Department's efforts included giving NSTAR Gas multiple opportunities to explain the discrepancy between CIACs booked to plant and CIACs received (see Exhs. DPU-ES 4-7; DPU-ES 12-23 through DPU-ES 12-27; DPU-ES 18-4 through DPU-ES 18-7; DPU-ES 21-9; Tr. 6, at 881-889; Tr. 8, at 1058-1065; RR-DPU-18; RR-DPU-24). After reviewing all of the CIACs received by NSTAR Gas between January 1, 2005 and December 31, 2018, the Department finds that the amount of CIACs received by NSTAR Gas from its customers through the test year is \$7,092,508 (Exh. DPU-ES 12-25, Atts. (b)-(c)). The Department further finds that the Company received \$369,909 more in CIACs between 2015 and 2018 than it booked to plant in service during the same period (Exh. DPU-ES 12-25, Atts. (b)-(g)).[89] Regardless of the ultimate use of CIAC, i.e., whether the amount of CIACs received by the Company is booked to specific project or not, the Company is in possession of these contributions and, thus, has received an interest-free source of capital from customers. D.P.U. 771, at 21-22; D.P.U. 18595, at 7-8; D.P.U. 18545, at 2-4. On this basis, the Department is persuaded that the $369,909 difference between the amount NSTAR Gas received from customers and the amount booked to projects should also be excluded from rate base. Therefore, the Department reduces the Company's plant in service by an additional $369,909.

In addition, with the inclusion of 2019 non-GSEP plant in rate base, the same adjustment is required for the CIAC received by NSTAR Gas in 2019. The record shows that NSTAR Gas received $1,300,304.82 of CIAC in 2019 but booked only $883,582.12 to plant in service (Exh. DPU-ES 12-25, Atts. (c), (h)). Therefore, consistent with our finding in Section V.B.3.4.i on the 2019 plant additions, we direct the Company to decrease the plant in service further by $416,723 to account for the portion of 2019 CIAC that is not included in the plant in service balance in its first annual PBRM filing.[90]

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89 Between 2015 and 2018, NSTAR Gas received the following in CIACs: $28,901.06 for 2015; $1,017,305.06 for 2016; $737,690.48 for 2017; and $674,082.44 for 2018—a total of $2,457,979.04 (Exh. DPU-ES 12-25, Atts. (b) and (c)). Between 2015 and 2018, NSTAR Gas booked the following in CIACs to plant in service: $27,203.17 for 2015; $832,153.42 for 2016; $445,039.39 for 2017; and $783,673.95 for 2018—a total of $2,088,069.93 (Exh. DPU-ES 12-25, Atts. (d)-(g)). CIACs received $2,457,979.04 less $2,088,069.93 CIAC booked to plant in service equals $369,909.11.

90 The rate base adjustment of $416,723 in the first PBRM filing is calculated by subtracting $883,582 from $1,300,305 (Exh. DPU-ES 12-25 & Atts. (c), (h)).

b. Accounting Treatment of CIAC

Turning to NSTAR Gas's method of accounting for CIAC, G.L. 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) at 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 CMR 50.00.[91] Notwithstanding the Company's apparent preference for FERC's accounting rules, the Department's accounting regulations, not those of FERC, govern NSTAR Gas's operations in Massachusetts.

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 CMR 50.00, USOA-Gas, Balance

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91 The Department has adopted the Uniform System of Accounts for Electric Companies prescribed by the FERC with several modifications. 220 CMR 51.01(1). The Department, however, has not adopted FERC's Uniform System of Accounts for Gas Companies. 220 CMR 50.00.

Sheet Accounts, Account 271. 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 CMR 50.00, USOA-Gas, 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. The Department has consistently required that CIAC be booked to Account 271 to ensure accounting transparency for ratemaking purposes. Bay State Gas Company, D.P.U. 12-25, at 114 (2012); New England Gas Company, D.P.U. 08-35, at 44-45 (2009); New England Gas Company, D.P.U. 07-46, at 9 (2007).

In maintaining this policy, the Department has recognized the evolution of the role of depreciation expense in the ratemaking process, and how this evolution has implications on our accounting treatment of CIAC. Boston Gas Company/Colonial Gas Company, D.P.U. 17-170, at 60-62 (2018). In view of these issues, the Department has reviewed

NSTAR Gas's CIAC proposal to create a new subaccount to Account 101/106, Utility Plant in Service, with the offset credit to Account 271, along with additional reporting in the Annual Return to the Department (Exh. DPU-ES 12-26 & Att.). Based on the Company's description of the process, including the illustrative journal entries provided during the proceedings and our review of the relevant provisions of 220 CMR 50.00, the Department finds that NSTAR Gas's proposal provides a reasonable approach in accounting for the Company's CIAC (Exhs. DPU-ES 4-7; DPU-ES 12-26 & Att.; RR-DPU-18). The proposal properly provides a separate account for CIAC, supports the integrity of the Department's prescribed accounting system, ensures accounting transparency for ratemaking purposes, and is consistent with similar proposals approved by the Department. Bay State Gas Company, D.P.U. 12-25, at 115 (2012); Boston Gas Company/Colonial Gas Company, D.P.U. 17-170, at 62 (2018). Therefore, we approve NSTAR Gas's proposal.

Because the Company's accounting practice has been longstanding, it may be difficult to identify and locate all of the work orders recording CIAC, and some portion of the CIAC may be associated with plant that has now been retired. 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 historically 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 $7,092,508, plus all CIAC received since the end of the test year (see Exhs. DPU-ES 12-26, Att.; DPU-ES 12-25 & Atts.). The Company shall distribute the $7,092,508 among the accounts listed in Exhibit DPU-ES 12-26 & Att. 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 ensure that its booking of depreciation expense does not result in depreciation being taken on CIAC. Milford Water Company, D.P.U. 84-135, at 32-33 (1985); Dedham Water Company, D.P.U. 84-32, at 18-20 (1984); Hingham Water Company, D.P.U. 1590, at 22-23 (1983).

3. Conclusion

Consistent with our findings above, the Department directs NSTAR Gas to make a $369,909 adjustment to its plant in service balance in compliance with this Order and a $416,723 adjustment in its first annual PBRM filing.[92] In addition, though NSTAR Gas failed to comply with the Department's directives in D.P.U. 14-150, at 108-109, concerning the Company's accounting treatment of CIAC, the Department has accepted the Company's proposal to create a separate account for CIAC because it supports the integrity of the Department's prescribed accounting system and ensures accounting transparency for ratemaking purposes (Exh. DPU-ES 4-7). Our decision is based on the specific facts and circumstances before us. We remind all entities under the Department's jurisdiction that a final Department Order remains in effect even when a party files a motion for recalculation,

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92 Regarding to the plant disallowed in the Company's previous rate case D.P.U. 14-150, the Department's decision in Section VII.F.2 does not require an adjustment on the CIAC in rate base.

reconsideration, or for an extension of the judicial appeal period. Aquarion Water Company of Massachusetts, Inc., D.P.U. 17-90, at 11 (2018), citing New England Telephone and Telegraph Company, D.T.E. 98-57, at 8 (2000). A regulated entity that disregards the Department's directives does so at its own peril. See Milford Water Company, D.P.U 12-86, at 275 (2013) (company's failure to comply with the Department's directives relating to affiliate transactions considered in the determination of the allowed return on equity); Aquarion Water Company of Massachusetts, Inc., D.P.U. 08-27, at 71, 137 (2009) (disregard for Department's directives concerning rate case expense considered in the determination of the allowed return on equity).

G. Conclusion

As discussed above, the Department allows the Company to include in rate base the costs associated with test-year end plant additions and costs previously disallowed in D.P.U. 16-GREC-06. The Department also allows the Company to include in rate base costs previously disallowed in D.P.U. 14-150, with the following exceptions: (1) $685,266 in variances associated with Project Nos. 13972, 13973, 13974 and 13978; and (2) $66,999 in total costs associated with project 99816, work order 1989745. As such, we will reduce the Company's proposed plant in service by $752,265. Further, the Department reduces the Company's proposed plant in service by $91,169 associated with the outstanding Massachusetts DOT reimbursement. Finally, the Department has determined that in the Company's initial PBR filing, for rates effective November 1, 2021, rate base will be updated to incorporate the 2019 non-GSEP plant additions along with the associated accumulated depreciation and property tax. As such, we will remove all costs tied to the 2019 plant additions and reduce the Company's proposed plant in service further by $63,485,375 (RR-DPU-14, Att. at 4).

In recognition of the Department's decision to exclude the above project costs from the Company's rate base, a corresponding adjustment to the Company's depreciation reserve is appropriate. D.P.U. 14-150, at 94; D.P.U. 12-25, at 83; D.P.U. 10-55, at 193-194; D.P.U. 08-27, at 16; D.T.E. 03-40, at 71. The total disallowances detailed above produce a $843,434 reduction to plant in service. The composite depreciation accrual rate from the Company's last rate case was 2.68 percent. D.P.U. 14-150, at 162. To calculate the accumulated depreciation associated with these projects, the Department multiplied the total disallowance of $843,434 by the 2.68-percent composite depreciation accrual rate approved in D.P.U. 14-150. The result is an annual accrual of $22,604. Applying the half year convention to the 2014 accrual, the accumulated depreciation associated with the disallowances is $101,718[93] and the accumulated depreciation balance will be reduced by this amount. A further adjustment of $23,006,632 to the accumulated depreciation account is appropriate in light of the removal of the 2019 non-GSEP plant additions (RR-DPU-14, Att. at 4). The combined adjustment to the accumulated depreciation account is $23,108,350. In

93 The disallowed plant was placed into service over the course of 2014. Applying half of the annual depreciation assumes that the plant additions were in service for six months of the year on average. A full year of depreciation on the plant is accrued for each subsequent year. The calculation is then $22,604 x 4.5 years = $101,718.

addition, the Department makes an adjustment to accumulated amortization of $425,082 corresponding to the removal of the 2019 non-GSEP plan additions (RR-DPU-14, Att. at 4).

Consistent with the Department's disallowance of $843,434 in plant additions from rate base, the Department must also adjust the Company's ADIT amount of $145,128,258 at the test year end to remove the deferred income taxes associated with the disallowed plant (Exh. ES-DPH/ANB-3, WP 29, at 2). 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 $254,596,232, inclusive of excess ADIT,[94] by the Company's total utility distribution plant included in base rates, adjusted per the Department's CIAC findings in Section VII.F, as of December 31, 2018, or $1,394,820,031[95] (Exhs. ES-DPH/ANB-3, Workpaper 29, at 2; ES-DPH/ANB-2, Sch. 27). D.P.U. 14-150, at 105; D.P.U. 13-90, at 61; D.P.U. 10-55, at 194; D.T.E. 01-56, at 43. This adjustment produces a factor of 18.25 percent which, when multiplied by the total net plant excluded from rate base of $843,434, produces a

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94 According to the Company, its reserve for deferred income taxes is calculated by deriving the total ADIT at the pre-TCJA income tax rate, and then adjusted by the FAS 109 liability, i.e., excess ADIT (Exh. ES-DPH/ANB-3, WP 29, at 2; Tr. 8, at 1101-1103). Therefore, the Department uses the plant-related ADIT, inclusive of excess ADIT at the end of 2018, of $254,596.232 to determine the appropriate ADIT adjustment calculation (Exh. ES-DPH/ANB-3, WP 29, at 2; Tr. 8, at 1101-1103).

95 Total distribution plant of $1,394,820,031 is calculated as $1,395,189,940 minus CIAC adjustments of $369,909 in Section VII.F (Exh. ES-DPH/ANB-2, Sch. 27, Line 24).

deferred income tax balance, inclusive of excess ADIT, of $153,952. Of this deferred income tax balance, $61,581[96] represents excess deferred income taxes the Department directed the Company to refund to ratepayers as a result of the TCJA. D.P.U. 18-15-E at 41-43. Because the excess ADIT balance is treated separately, as described below, its removal from this component of ADIT is warranted. The exclusion of this excess ADIT balance from this calculation produces a deferred income tax balance of $92,371. Accordingly, the Department reduces the Company's test year end deferred income tax reserve by $92,371, resulting in a revised ADIT balance of $145,035,886.

Turning to the excess ADIT balance to be included in rate base, a test year is intended to provide a representative level of a company's revenues and expenses which, when adjusted for known and measurable changes, will serve as a proxy for future operating results. D.T.E. 99-118, Interlocutory Order Regarding Scope of Proceeding and Motion to Compel Discovery at 8; D.P.U. 95-92, at 28; D.P.U. 84-25, at 68-69; D.P.U. 1580, at 13-17; D.P.U. 1438/1595, at 3-4. NSTAR Gas reported its excess ADIT balance of $114,899,004 at the test year end (Exh. ES-DPH/ANB-3, WP 29, at 2). The Company provided the actual 2019 excess ADIT refund amount of $282,686 in the GSEP and $1,684,852 in the TACF (Exh. DPU-ES 27-3, Att. at 4). To reflect the inclusion in base distribution rates of the TACF and GSEP related excess ADIT balances, the Department reduces the Company's test

[96] The excess deferred income tax of $61,581 is calculated using the total deferred income tax balance of $153,952 divided by 35 and multiplied by 14, representing the 14-percentage point tax cut resulting from the TCJA.

year end excess ADIT by $1,967,538[97], resulting in a revised excess ADIT balance of $112,931,466. In addition, NSTAR Gas provided the 2020 excess ADIT refund amount of $277,859 in the GSEP and $2,681,899 in the TACF (Exh. DPU-ES 27-3, Att., at 4). These amounts represent known and measurable changes to the excess ADIT balance. To adjust for these amounts, the Department further decreases the excess ADIT balance by $2,466,465[98] to arrive at the final balance of $110,465,001.

# VIII. OPERATIONS AND MAINTENANCE EXPENSES

## A. 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 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

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97 The 2019 excess ADIT refund amount of $1,967,538 is derived from the sum of $282,686 related to the excess ADIT refund in the GSEP and $1,684,852 in the TACF.

98 The adjustment of $2,466,465 represents ten months of the excess ADIT refund in 2020 and is calculated by multiplying the excess ADIT refund in the GSEP of $277,859 and the TACF of $2,681,899 by 10 and dividing by 12.

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); Massachusetts Electric Company, D.P.U. 92-78, at 25-26 (1992).

2. Non-Union Wages

a. Introduction

During the test year, NSTAR Gas booked $15,474,689 in payroll expense for non-union personnel, including base wages and overtime pay (Exh. ES-DPH/ANB-2 (Rev. 3), Sch. 10, at 2). NSTAR Gas proposes to increase its non-union payroll expense by $1,490,113 based on the following: (1) a non-union wage increase of three percent effective April 1, 2019; (2) a non-union wage increase of three percent effective April 1, 2020; (3) a non-union wage increase of 2.5 percent effective April 1, 2021; and (4) gas acquisition costs (Exh. ES-DPH/ANB-2 (Rev. 3), Sch. 10, at 2-3).

The Company tested the competitiveness and reasonableness of its non-union base salaries and total compensation levels against external market trends for energy/utility companies and general industry sectors using studies performed by Towers Watson (Exhs. ES-SL-1, at 14-15; ES-SL-5; ES-SL-6; ES-SL-7, AG 13-7, Att. (a)-(g)). In addition, the Company provided a historical comparison of non-union base wage increases to union base wage increases (Exh. ES-SL-4).

b. Positions of the Parties

i. Attorney General

The Attorney General asserts that the Department should deny NSTAR Gas's proposed 2020 and 2021 non-union pay increases (Attorney General Brief at 36). The Attorney General argues that the current worldwide COVID-19 pandemic has caused unprecedented hardship for NSTAR Gas's customers, and, therefore, the Company should avoid unnecessary wage and salary increases in order to maintain a conservative financial position and minimize its cost of service (Attorney General Brief at 36-37). The Attorney General claims that the Company's 2020 and 2021 proposed non-union discretionary pay increases are inappropriate and unreasonable in light of the current high unemployment rate in Massachusetts and the challenges customers face in paying bills (Attorney General Brief at 36-38). For these reasons, the Attorney General recommends that the Department deny the Company's proposed non-union payroll increases (Attorney General Brief at 37).

ii. Company

NSTAR Gas claims that, prior to the COVID-19 pandemic and consistent with its past practice, it committed to a 2021 non-union merit increase for its non-union employees and had already granted merit increases for 2019 and 2020 (Company Brief at 314, citing Exhs. ES-SL-1, at 14; DPU-ES 4-43; DPU-ES 4-44, Supp. 1). The Company explains that, when deciding merit increases, it reviews salary adjustments and total compensation, both current and projected, against external market trends for energy/utility companies and general industry to determine if they are reasonable (Company Brief at 314-315, citing Exh. ES-SL-1, at 14). Further, NSTAR Gas insists that because these merit increases were committed to prior to the pandemic, they cannot be considered unreasonable given market trends (Company Brief at 315, citing Exh. ES-SL-1, at 14). The Company maintains that it is impossible for it to base its merit increases on unknown future events (Company Brief at 315).

Further, the Company points out that the Department has determined that, regardless of economic conditions, the rates being set are to be in effect for several years, and utilities must remain competitive in attracting and retaining skilled employees in order to meet their public service obligations (Company Brief at 315, citing New England Gas Company, D.P.U. 08-35, at 86 (2009)). NSTAR Gas affirms that its rates will be in effect for at least five years if its proposals are approved in this proceeding, and, therefore, the 2020 and 2021 non-union wage increases are reasonable considering the economic future (Company Brief at 315).

c. Analysis and Findings

The Department's well-established standard for post-test year non-union payroll adjustments requires a company to demonstrate that (1) the non-union salary increase is scheduled to become effective no later than six months after the date of the Department's Order; (2) if the increase has not occurred, there is an express commitment by management to grant the increase; (3) there is a historical correlation between union and non-union raises; and (4) the non-union increase is reasonable. D.P.U. 85-266-A/85-271-A at 107;

D.P.U. 96-50 (Phase I) at 42; D.P.U. 95-40, at 21; Fitchburg Gas and Electric Light Company, D.P.U. 1270/1414, at 14 (1983).

Two of Company's proposed non-union wage increases occurred before the issuance of the Department's Order: one on April 1, 2019, and the other on April 1, 2020 (Exhs. ES-DPH/ANB-2 (Rev. 3), Sch. DPH-10, at 3; DPU-ES 4-44 (Supp. 1), Att.). NSTAR Gas provided a confirmation of the 2020 increase in the form of a written letter from management verifying the increase (Exh. DPU-ES 4-44 (Supp. 1), Att.). Regarding the third proposed increase, NSTAR Gas provided a commitment letter from its management stating that a 2.5-percent payroll increase for non-union employees will take place on or before March 21, 2021 (Exh. DPU-ES 4-44 (Supp. 2), Att.). Based on this information, the Department finds that non-union salary increases have or will become effective no later than six months after the issuance of this Order, and there is a commitment by management to grant the increase that has not yet occurred.

In addition, NSTAR Gas provided a historical correlation of non-union and union wage increases and demonstrated that it awarded non-union and union pay increases every year since 2015 (Exh. ES-SL-4). Between 2015 and 2019, union wage increases were between 2.50 percent and 3.25 percent, and non-union wage increases were all three percent (Exh. ES-SL-4). Based on this information, the Department finds that a sufficient correlation exists between union and non-union wage increases. Fitchburg Gas and Electric Light Company, D.P.U. 07-71, at 76 (2008); Essex County Gas Company, D.P.U. 85-59-A at 18 (1988).

Next, the Department examines the reasonableness of the proposed non-union wage increases. The Attorney General argues that the proposed non-union salary increases are inappropriate because of the financial hardships that customers now face as a result of the COVID-19 pandemic and the high unemployment rate in Massachusetts (Attorney General Brief at 36-38). The Department recognizes the adverse economic impact of the COVID-19 pandemic on the Commonwealth and the difficulties faced by its residents. The Department, however, sets rates that are intended to be in effect for several years. Moreover, utilities must remain competitive in attracting and retaining skilled employees to meet their public service obligations. Therefore, while we are sensitive to the prevailing economic conditions, the Department also is obligated to consider what reasonable payroll increases may be on a going-forward basis. D.P.U. 08-35, at 86.

NSTAR Gas annually reviews its current and projected salary levels against external market trends associated with energy/utility companies and the general industry to determine if the Company's projected salary levels are reasonable and closely align with relevant markets (Exh. ES-SL-1, at 14). In the instant case, NSTAR Gas used survey data from Towers Watson to provide (1) a comparison of NSTAR Gas non-union base salaries and total cash compensation against median base salaries and total cash compensation in the energy/utility and general industry sectors in the Northeast; (2) a comparison of ESC base salaries and total cash compensation against median base salaries and total cash compensation in the energy/utility sector; and (3) the prevalence of companies that provided merit increases for 2017-2019, arrayed by general industry and energy/utility sectors as well as by employee level (Exhs. ES-SL-1, at 15; ES-SL-5; ES-SL-6; ES-SL-7; AG 13-7, Att. (a)-(g)). Although NSTAR Gas's source data predated the COVID-19 pandemic, we find that the data accurately and appropriately reflects market conditions existing at that time. The results of the comparisons demonstrate that NSTAR Gas's non-union total cash compensation is 100.4 percent of the external market and ESC's non-union total cash compensation is 103.5 percent of the external market (Exhs. ES-SL-1, at 16-18; ES-SL-5; ES-SL-6). Thus, we conclude that the Company's proposed total compensation is closely aligned with energy/utility and general industry data, as it existed at the time of the comparisons. Further, the data provided shows that the Company's practice of providing merit increases to its employees and to ESC employees supporting NSTAR Gas is fully consistent with the industry norm (Exhs. ES-SL-1, at 21; ES-SL-7). The record shows that the Company's proposed non-union increases are in the median range; therefore, we find that they are reasonable.

The Department has determined that (1) the proposed non-union wage increases are scheduled to become effective no later than six months after the Department's Order; (2) there is an express management commitment to grant a 2.5-percent non-union wage increase that is scheduled to occur after the date of this Order; (3) there is a historical correlation between union and non-union payroll increases; and (4) the proposed increases are reasonable. Accordingly, the Department allows the Company's adjusted non-union payroll expense.

### 3. Union Wages

#### a. Introduction

During the test year, NSTAR Gas booked $15,995,484 in payroll expense for union personnel, including base wages and overtime pay (Exh. ES-DPH/ANB-2 (Rev. 3), Sch. 10, at 2-3). NSTAR Gas proposes to increase its union payroll expense by $1,248,263 based on the following: (1) a Local 12004, United Steelworkers of America, AFL-CIO ("Local 12004") union wage increase of 2.5 percent effective April 1, 2019; (2) a Local 369 of the Utility Workers Union of America, AFL-CIO 10 ("Local 369") union wage increase of three percent effective June 2, 2019; (3) a Local 12004 union wage increase of three percent effective April 1, 2020; (4) a Local 369 union wage increase of three percent effective June 2, 2020; and (5) a Local 12004 union wage increase of three percent effective April 1, 2021 (Exh. ES-DPH/ANB-2 (Rev. 3), Sch. 10, at 3).

#### b. Positions of the Parties

##### i. Attorney General

The Attorney General does not oppose the Company's proposed adjustments to payroll expense for union increases (Attorney General Brief at 37 n.16). The Attorney General asserts that because the Company's management negotiated prudent, long-term labor contracts with its employee unions that are legally binding, it would be appropriate to include those costs in the pro forma cost of service (Attorney General Brief at 37 n.16, citing Tr. 8, at 1188-1189).

ii. Company

The Company affirms that its union wages are established through collective-bargaining agreements involving arm's length negotiations with two unions, Local 369 and Local 12004 (Company Brief at 188; 295). NSTAR Gas states that it has included only union increases effective by May 1, 2021, the midpoint of the rate year, based on actual wage increases in 2019 and 2020, and planned increases in 2021 (Company Brief at 189). Further, NSTAR Gas explains that, to determine whether its union wages are competitive, it analyzed the average hourly union wages compared to other employers in the Northeast (Company Brief at 295, citing Exhs. ES-SL-1, at 7; ES-SL-2). The Company states that the results of this analysis showed that the hourly rates paid to its union employees are comparable to the median hourly rates of other Northeast employers and that the hourly rates, including variable compensation, are comparable to the median of other Northeast employers (Company Brief at 295, citing Exh. ES-SL-1, at 8). Thus, the Company maintains that it has demonstrated that its union compensation costs are reasonable, appropriate, and should be approved by the Department for recovery (Company Brief at 190, 295).

c. Analysis and Findings

The Department's standard for recovery of post-test year 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. 11-01/D.P.U. 11-02, at 174; D.P.U. 96-50 (Phase I) at 43; D.P.U. 95-40, at 20; D.P.U. 92-250, at 35.

The Company's proposed union payroll adjustments appropriately include only those increases that will have been granted before May 1, 2021, the midpoint of the first twelve months after the issuance of the Department's Order in this proceeding (Exh. ES-DPH/ANB-2 (Rev. 3), Sch. 10, at 3). The union payroll increases that occurred in 2019 and 2020 are based on signed collective bargaining agreements and memorandums of agreement between the Company and the respective unions (Exhs. AG 1-42(c), Att.; AG 1-42(e), Att.; DPU-ES 4-44(b), Att.). Additionally, the memorandum of agreement between NSTAR Gas and Local 12004, provided to the Department on June 16, 2020, verifies that a three-percent payroll increase for Local 12004 union employees of NSTAR Gas will take effect on April 1, 2021 (Exh. DPU-ES 4-44(b), Att.). Thus, the Department finds that the Company's proposed union wage increases are known and measurable.

Further, with respect to the reasonableness of the union wage increases, the Company submitted a comparison of its 2018 average union wages with other employers in the Northeast (Exhs. ES-SL-1, at 8; ES-SL-2). This analysis demonstrates that hourly rates paid to the Company's union employees were comparable to the median hourly rates of other employers in the region for the selected union job titles (Exh. ES-SL-2). Thus, we find that the Company has demonstrated the reasonableness of its union wage increases, based on market data existing at the time of the comparison. Based on the above, the Department finds that NSTAR Gas has demonstrated the following: (1) the Company's post-test year union payroll adjustments are scheduled to take effect before the midpoint of the first twelve months after the date of the rate increase; (2) the proposed union wage increases are known and measurable; and (3) the proposed union wage increases are reasonable. Accordingly, we allow the Company's adjusted union payroll expense.

4. Incentive Compensation

a. Introduction

The Company's incentive compensation represents the portion of wages and salaries paid to non-union employees of NSTAR Gas, and it is paid in March for performance in the prior year (Exh. ES-DPH/ANB-1, at 49). During the test year, NSTAR Gas booked $3,366,683 in incentive compensation for non-union personnel (Exh. ES-DPH/ANB-2 (Rev. 3), Sch. 12). The Company proposes to decrease its incentive compensation by $1,105,676 (Exh. ES-DPH/ANB-2 (Rev. 3), Sch. 12).

The factors contributing to the lower amount of proposed rate year incentive compensation expense are as follows: (1) the test year level of expense was normalized to remove out-of-period and non-recurring items; (2) the Company reduced the revenue requirement to include incentive compensation at target levels because NSTAR Gas paid incentive compensation at greater than target levels in the test year; and (3) the incentive compensation amounts allocated to the Company for the Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO") were removed from the revenue requirement (Exhs. ES-DPH/ANB-1, at 48; ES-SL-1, at 24 n.2; ES-DPH/ANB-2 (Rev. 3), Schs. 9, 12, at 2; DPU-ES 4-49, at 2; DPU-ES 4-51, at 2; DPU-ES 4-52; DPU-ES 4-53, at 3).

b. Positions of the Parties

i. Attorney General

The Attorney General argues that the Department should disallow the Company's incentive compensation costs because its incentive compensation plan is not reasonably designed to encourage good employee performance (Attorney General Brief at 30-31). First, the Attorney General reasons that incentive compensation is awarded to almost all of the Company's eligible employees, noting that 99.85 percent of employees received incentive compensation in 2018, including employees who needed improvement to be successful contributors (Attorney General Brief at 31, citing Exhs. ES-SL-Rebuttal-1 at 5; AG-L&A-1, at 4). Second, the Attorney General contends that a plan design where employees receive 100 percent of the target incentive simply by performing their regular job duties provides little incentive for employees to provide exemplary performance (Attorney General Brief at 32, citing Exh. ES-SL-Rebuttal-1 at 6). Therefore, according to the Attorney General, NSTAR Gas's plan is not designed to encourage good employee performance, and the Department should eliminate all incentive compensation costs from the Company's revenue requirement (Attorney General Brief at 32).

Alternatively, if the Department does allow the Company to recover its incentive compensation plan costs, the Attorney General argues that the Department should reduce the incentive compensation costs by 70 percent because 70 percent of the Company's annual incentive performance goals for 2018 were based on financial performance, and 30 percent were based on operational performance (Attorney General Brief at 32, citing Exhs. AG-L&A-1, at 5-6; AG 24-25). The Attorney General claims that the Company has not demonstrated how financial goals and success through incentive compensation directly benefits ratepayers (Attorney General Brief at 32).

ii. Company

The Company argues that its incentive compensation plan structure at issue is identical to the plan reviewed and approved by the Department in D.P.U. 14-150, its last base rate proceeding, and D.P.U. 17-05, NSTAR Electric Company's most recent base distribution rate proceeding (Company Brief at 311, citing Exh. ES-SL-Rebuttal-1, at 3). NSTAR Gas asserts that the Attorney General has provided no evidence to supports the Department's divergence from established precedent, and that the Attorney General misunderstands the Company's incentive compensation plan (Company Brief at 311).

First, NSTAR Gas argues that the Attorney General's claim that the Company's incentive plan does not motivate good employee performance because almost all employees receive some incentive compensation is flawed and ignores important facts about the program (Company Brief at 311, citing Exh. ES-SL-Rebuttal-1, at 5-6). The Company explains that performance metrics and actual incentive compensation vary for every employee and are determined based on their eligible pay and target incentive levels, then adjusted up or down to use available funding based on management's assessment of their individual performance and contribution overall (Company Brief at 311, citing Exhs. ES-SL-Rebuttal-1, at 5; AG 13-1, Att. (a)). The Company notes that, because management has the discretion to set the award based on the employee's performance and job-specific goals, no employee is guaranteed an incentive compensation award or a certain level of incentive compensation

(Company Brief at 311, citing Exhs. ES-SL-Rebuttal-1, at 6; AG 13-1, Att. (a)). Thus, NSTAR Gas asserts that if almost all of its employees receive incentive compensation, it does not mean that the incentive compensation program is flawed, but rather that the Company's employees are properly fulfilling their duties (Company Brief at 311-312, citing Exhs. ES-SL-Rebuttal-1, at 6; AG 13-1, Att. (a)).

Second, the Company asserts that, even though each employee is likely to receive 100 percent of the target for fulfilling the requirements of the position, the Attorney General overlooks the fact that the requirements are established based on the achievement of individual goals and that an employee can receive up to 200 percent of the target amount (Company Brief at 312, citing Exh. ES-SL-Rebuttal-1, at 4, 6). NSTAR Gas explains that when employees reach their goals, the payout is 100 percent; however, there are employees that receive less or more than 100 percent if they perform below their target goals or go above and beyond their target goals (Company Brief at 312, citing Exh. ES-SL-Rebuttal-1, at 4, 6). Therefore, according to the Company, the incentive compensation program is designed to encourage good employee performance because, although employees receive incentive compensation for fulfilling their requirements, they can and do achieve more if their overseeing manager determines that they were a high contributor or top achiever (Company Brief at 312, citing Exh. ES-SL-Rebuttal-1, at 4, 6).

Moreover, the Company contends that the Attorney General's argument that the financial goals and success related to incentive compensation do not benefit ratepayers is unfounded (Company Brief at 313). NSTAR Gas states that financial performance goals for employees include performance on budget control, identifying and achieving operating expense reductions, and other similar financial results occurring within the scope of the employee's position over which the employee has direct input or control (Company Brief at 313, citing Exh. ES-SL-Rebuttal-1, at 10). These measures are directly aligned with the interests of ratepayers, according to the Company, because the plan drives employee excellence, which, in turn, benefits customers (Company Brief at 313, citing Exh. ES-SL-Rebuttal-1, at 10-11). NSTAR Gas asserts that the Department has found appropriate this type of incentive plan utilizing financial incentives as a threshold component as the basis for determining individual compensation awards (Company Brief at 313, citing D.P.U. 17-05, at 143-145; D.P.U. 14-150, at 147; D.P.U. 13-75, at 157; D.P.U. 10-55, at 253-254).

Finally, the Company maintains that the Department has found that using job performance metrics as the basis for determining individual compensation awards is appropriate given that these measures are directly aligned with the interests of customers (Company Brief at 313, citing D.P.U. 14-150, at 146; D.P.U. 13-75, at 156-157). The Company emphasizes that there is no individual in its organization who is awarded incentive compensation on the basis of earnings per share, dividend growth, and credit rating other than the CEO (Company Brief at 314, citing Exhs. ES-SL-Rebuttal-1, at 9-10; DPU-ES 4-49, at 2; DPU-ES 4-50). Therefore, the Company reiterates that the Department should reject the Attorney General's recommendation to exclude 70 percent of the Company's incentive compensation costs and, instead, approve the full incentive compensation amount requested in this proceeding (Company Brief at 314).

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 plan is reasonably designed to encourage good employee performance. D.P.U. 07-71, at 82-83; Massachusetts Electric Company, D.P.U. 89-194/195, at 34 (1990). 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.

First, the Department must determine whether the costs associated with NSTAR Gas's incentive compensation program are reasonable in amount. The Company normalized the test-year level of expense to remove out-of-period and non-recurring items (Exhs. ES-DPH/ANB-1, at 48; ES-DPH/ANB-2 (Rev. 3), Schs. 9, 12, at 2). Further, since the Company awarded incentive compensation payouts above the target level during the test year, it reduced the revenue requirement to include only the amount of incentive compensation at target levels (Exhs. ES-DPH/ANB-1, at 48; ES-DPH/ANB-2 (Rev. 3), Schs. 9, 12, at 2). Finally, NSTAR Gas removed incentive compensation for the CEO and CFO from the revenue requirement (Exhs. ES-DPH/ANB-1, at 48; ES-SL-1, at 24 n.2; ES-DPH/ANB-2 (Rev. 3), Schs. 9, 12, at 2; DPU-ES 4-49, at 2; DPU-ES 4-51, at 2; DPU-ES 4-52; DPU-ES 4-53, at 3). Based on our review of this evidence, the Department finds that NSTAR Gas has demonstrated that its incentive compensation costs are reasonable in amount. D.P.U. 17-05, at 143; D.P.U. 10-70, at 103; D.P.U. 09-39, at 140.

Second, the Department must determine whether the Company's incentive compensation plan is reasonably designed to encourage good employee performance. In order for an incentive plan to be reasonable in design, it must both encourage good employee performance and result in benefits to ratepayers. D.T.E. 03-40, at 124; D.P.U. 93-60, at 99. Benefits to ratepayers may be demonstrated by a showing that the selected performance goals are reasonably designed to provide a direct benefit to ratepayers that rewards management incentives and do not penalize employees for events beyond the company's control. D.T.E. 02-24/25, at 101.

The record shows that NSTAR Gas's incentive compensation program is based on the individual performance of the employee as it relates to pre-designed goals, including customer, employee, process/capability, operational, and other goals, necessary for NSTAR Gas to provide safe, reliable, and cost-effective service to customers (Exhs. ES-SL-1, at 26, 31; ES-SL-Rebuttal-1, at 5; 9; DPU-ES 4-47, Att. (b); DPU-ES 4-48). For example, goals that support improved customer service include customer satisfaction responses and managing emergency response average response times, while field operations employees have goals related to safety and reliability (Exhs. ES-SL-1, at 26, 31; ES-SL-Rebuttal-1, at 9; DPU-ES 4-47, Att. (b)). The performance goals for each Company employee revolve around successful execution of responsibilities within the scope of the individual employee's job position and the successful completion of specified projects (Exhs. ES-SL-Rebuttal-1, at 9;

DPU-ES 4-48). Payment to the employee is based on the employee's individual performance in achieving the pre-determined goals relating to their position, as determined by their supervisor (Exhs. ES-SL-1, at 26; ES-SL-Rebuttal-1, at 5). Further, the employee must remain engaged and focused on achieving the goals outlined in their individual performance plan in order to be considered for an incentive compensation award (Exh. ES-SL-Rebuttal-1, at 10). Thus, the Company uses job performance measures as the basis for determining individual compensation awards and the incentive pay component of employee compensation is designed to drive and reinforce the performance goals set for each employee each year (Exhs. ES-SL-1, at 26; ES-SL-Rebuttal-1, at 11).

The Department has found that using job performance measures as the basis for determining individual compensation awards is appropriate given that these measures are directly aligned with the interests of customers. D.P.U. 17-05, at 147; D.P.U. 14-150, at 146; D.P.U. 13-75, at 156-157. Therefore, the Department declines to adopt the Attorney General's position that the Company's incentive compensation plan is not designed to encourage good employee performance. We find that NSTAR Gas's incentive compensation plan is reasonably designed to encourage good employee performance because the Company ensures that its employees are committed to meeting customer needs by establishing performance goals that are based on providing safe and reliable services at reasonable costs to customers (Exhs. ES-SL-1, at 26, 31; ES-SL-Rebuttal-1, at 5, 9-11; DPU-ES 4-47, Att. (b); DPU-ES 4-48).

The Attorney General argues that the Department should reduce the Company's incentive compensation costs by 70 percent because she claims that 70 percent of the Company's annual incentive performance goals in 2018 were based on financial performance (Attorney General Brief at 120). We disagree. The record shows that NSTAR Gas utilizes financial goals, specifically earnings per share and high-level financial goals, as the trigger for funding the incentive compensation program in a given year (Exh. ES-SL-Rebuttal-1, at 3). If the Company is in a sufficiently healthy financial position, as determined by achievement of pre-determined financial goals, the money will be available to fund the incentive compensation pool from which individual employee incentive compensation will be drawn (Exh. ES-SL-Rebuttal-1, at 4). Thus, the decision to fund the pool requires confirmation that the organization has sufficient resources to meet the commitment, and the earnings per share goal provides a measure of confirmation of the Company's financial resources and acts as a trigger as to whether incentive compensation will be paid to employees (Exhs. ES-SL-Rebuttal-1, at 4; DPU-ES 4-52; AG 13-5). Once the decision has been made to fund the incentive compensation pool, an employee must meet the second threshold step in order to be awarded incentive compensation; specifically, an employee must demonstrate that they have achieved those employee- and job-specific goals set out in the employee's job performance plan, as described above (Exhs. ES-SL-Rebuttal-1, at 5; AG 13-5).

Further, the record shows that the CEO is awarded incentive compensation on the basis of earnings per share, dividend growth and credit rating, while the CFO is awarded incentive compensation based on the achievement of individual goals, as well as on the achievement of the overall corporate financial goals of earnings per share and credit rating (Exhs. ES-SL-1, at 24-25; ES-SL-Rebuttal-1, at 9-10; DPU-ES 4-50). The Company already has removed 100 percent of incentive compensation costs for the CEO and CFO from the proposed cost of service (Exhs. ES-DPH/ANB-1, at 48; ES-SL-1, at 24 n.2; ES-DPH/ANB-2 (Rev. 3), Schs. 9, 12, at 2; DPU-ES 4-49, at 2; DPU-ES 4-51, at 2; DPU-ES 4-52; DPU-ES 4-53, at 3).

The Department previously has found to be appropriate an incentive plan that utilizes financial incentives as the threshold component (i.e., to determine whether the incentive plan will be funded), and then uses job performance measures, such as objectives related to safety, customer service, and process improvement as the basis for determining individual compensation awards. D.P.U. 17-05, at 143-145; D.P.U. 14-150, at 147; D.P.U. 13-75, at 157; D.P.U. 10-55, at 253-254. Based on the record, the Department finds that NSTAR Gas uses financial performance measures as threshold requirements (i.e., to decide whether to fund its incentive compensation program in a given year) and uses job performance measures as the basis for determining individual employee compensation awards (Exhs. ES-SL-Rebuttal-1, at 3-5; DPU-ES 4-52; AG 13-5). Therefore, we find that the Company is administering its incentive compensation program consistent with Department requirements and precedent.

Based on these considerations, the Department concludes that the incentive compensation paid to the Company's non-union employees other than the CEO and CFO is consistent with Department precedent and, therefore, we decline to adopt the Attorney General's recommendation. The Department allows the Company's proposal to decrease its test-year level of incentive compensation by $1,105,676 (Exh. ES-DPH/ANB-2 (Rev. 3), Sch. 12).

5. Supplemental Executive Retirement Plan

a. Introduction

Eversource Energy offers a Supplemental Executive Retirement Plan ("SERP") to certain high-level executives[99] as part of its overall compensation package, which is allocated to Eversource Energy subsidiaries including NSTAR Gas (Exhs. ES-SL-Rebuttal-1, at 15-17; AG 13-30; AG 21-3, Att. 1 (electric)). The SERP is a non-qualified benefit plan that provides these executives with a supplemental retirement benefit in addition to the benefit provided under the qualified benefit pension plan (Exh. AG 13-32). The test-year SERP expense for NSTAR Gas was $503,551 and, as it is imbedded in the Company's residual

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99 These executives include the Eversource Energy Chief Executive Officer, Chief Financial Officer, Chief Operating Officer, Executive Vice President – Enterprise Energy Strategy and Business Development, and Executive Vice President and General Counsel (Exhs. ES-SL-Rebuttal-1, at 15 n.2; AG 1-2, Att. 6(f) at 53 (named executives)).

O&M expense, is subject to an inflation escalation (Exhs. DPU-ES 34-9(d); AG 28-1 (Supp.), Att.).

b. Positions of the Parties

i. Attorney General

As an initial matter, the Attorney General contends that it is appropriate for the Department to review the SERP as a separate component of compensation, apart from salaries, incentive compensation, and other types of employee compensation (Attorney General Brief at 29, citing D.P.U. 17-170, at 68-104). Further, she notes that a number of jurisdictions have carved out and either disallowed or limited SERP recovery (Attorney General Brief at 29, citing Exh. AG-L&A-1, at 15-16).

Regarding NSTAR Gas's proposal, the Attorney General argues that SERP benefits are excessive and, therefore, they should be excluded from the Company's cost of service (Attorney General Brief at 28). Further, she contends that beyond providing generic studies of median salary levels, the Company has failed to adequately demonstrate that the SERP is necessary for acquiring and retaining high-level executives, or that past performance by such executives would have been different absent the SERP (Attorney General Brief at 29-30, citing Exh. AG-L&A-Surrebuttal, at 13, 16-17). According to the Attorney General, ratepayers should not have to bear the costs of excessive retirement benefits to "already well-compensated executives," especially where there has been no showing that the SERP provides any benefits to ratepayers (Attorney General Brief at 30, citing Exh. AG-L&A-1, at 15). Rather, she asserts that if NSTAR Gas wishes to provide this "generous plan" to its executives, its shareholders should bear the costs (Attorney General Brief at 30).

ii. Company

NSTAR Gas argues that the SERP is part of an overall compensation package and is the industry norm for higher level executive positions (Company Brief at 317, citing Exh. ES-SL-Rebuttal-1, at 15). According to the Company, Eversource Energy must remain competitive with other employers seeking to retain certain high-level executives, and this attraction and retention plan includes providing attractive overall compensation packages (Company Brief at 317, citing Exh. ES-SL-Rebuttal-1, at 15). Further, the Company contends that these executives, through their employment, accept a significant obligation to provide safe, reliable gas service at a reasonable cost, and that ratepayers benefit from being served by such highly qualified and skilled individuals (Company Brief at 317-318, citing Exhs. ES-SL-Rebuttal-1, at 16-17; DPU-ES 34-9). In particular, the Company notes that under the leadership of these high-level executives, ratepayers enjoyed a 24-year interval of unchanged base distribution rates prior to D.P.U. 14-150 (Company Brief at 318, citing Exh. ES-SL-Rebuttal-1, at 16).

Based on these considerations, the Company argues that it is clear that the SERP is an important component of an overall compensation package intended to retain certain high-level executives and should not be considered separately from other forms of compensation (Company Brief at 319). Accordingly, NSTAR Gas asserts that the Department should reject the Attorney General's recommendations and approve the Company's proposal (Company Brief at 318).

c. Analysis and Findings

When determining the reasonableness of a company's compensation expense, the

Department reviews the company's overall employee compensation expense to ensure that its 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; D.P.U. 92-250, at 55. This approach recognizes that the different components of compensation (e.g., wages and benefits) are to some extent substitutes for each other and that different combinations of these components may be used to attract and retain employees. D.P.U. 10-114, at 124; D.P.U. 92-250, at 55. The Department has considered a SERP in the context of an employee's overall compensation. D.P.U. 11-01/D.P.U. 11-02, at 206-207.

The Attorney General raises two issues with the Company's SERP plan. She argues that the Company has failed to adequately demonstrate that (1) the SERP, as a specific component of compensation, is necessary for acquiring and retaining high level executives or (2) past performance by such executives would have been different absent the SERP (Attorney General Brief at 29-30, citing Exh. AG-L&A-Surrebuttal, at 13, 16-17). The Department is not persuaded by these arguments. The SERP is one component of an overall compensation plan designed to attract and retain highly qualified and skilled executives who are tasked with ensuring that the Company provides safe, reliable gas service at a reasonable cost to its customers (Exhs. ES-SL-Rebuttal-1, at 15-16; DPU-ES 34-9, at 1-2). We are not inclined to adopt the Attorney General's reasoning, which would require the Company to specifically measure the impact of the SERP, as a standalone component of overall compensation, on an executive's employment decision or job performance. Such a requirement would be impractical and is inconsistent with the Department's practice of evaluating overall compensation in determining reasonableness. D.P.U. 10-55, at 234.

Second, the Attorney General argues that the certain executives are already well compensated, the SERP is excessive, and shareholders should bear these costs, especially where there has been no showing that the SERP provides any benefits to ratepayers (Attorney General Brief at 30). We disagree. The SERP is available to only certain high-level executives. Further, when considered in the context of overall compensation paid to these certain executives, we do not find the amount of the SERP to be excessive or unreasonable (Exhs. AG 1-2, Att. 6(f) at 53; AG 1-2, Att. 1(e) at 172; AG 28-1 (Supp.), Att.). Finally, it stands to reason that ratepayer interests are well served by highly qualified and skilled executives. As such, we are not convinced that NSTAR Gas must specifically quantify ratepayer benefits associated solely with the SERP for those costs to be recoverable as part of the Company's overall compensation expense.

Based on all of the above considerations, the Department finds that the proposed costs of the SERP should be included in the Company's cost of service. Accordingly, the Company may include $503,551 in test-year costs in its residual O&M expense, and this amount shall be subject to the appropriate inflation escalation as discussed below in Section VIII.J.3.

6. Employee Benefits

a. Introduction

ESC contracts for health care coverage and other employee benefits for the Eversource Energy operating subsidiaries including NSTAR Gas (Exh.ES-MPS-1, at 5).

During the test year, NSTAR Gas booked $5,489,758 in employee benefits expense (Exh. ES-DPH/ANB-2 (Rev. 3), Sch. 14). The Company proposes to increase its employee benefits expense by $736,604, comprising the following adjustments: (1) an increase of $690,281 for health care expense (i.e., medical/prescription, vision, and dental) based on a 4.1-percent working rate;[100] and (2) a gas acquisition reclassification adjustment of $46,323 (Exhs. ES-DPH/ANB-1, at 51-52; ES-MPS-2; ES-DPH-2 (Rev. 3), Sch. 14, at 2).

b. Positions of the Parties

i. Attorney General

The Attorney General argues that Department should reject the Company's position because it self-insures and its proposed adjustment to medical costs is based on working rates that the company's consultant develops, not contractual increases (Attorney General Brief at 39-40). The Attorney General claims that the working rate is based on a forecasted growth rate in health care costs that the Company creates and does not represent any actual increase in the Company's employee medical costs, and, therefore, it is not "known" (Attorney General Brief at 40, citing Exh. ES-MPS-1, at 10-12).

Further, the Attorney General claims that the Company's working rate grossly overestimates NSTAR Gas's future health care expense because using health care costs from calendar year 2018 as the basis for the pro forma adjustment is an unreliable and unreasonable estimate of the Company's future medical expense (Attorney General Brief

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100 A "working rate" represents the per-employee expected claims levels for the following year and is provided by ESC's external benefits consultants (Exhs. ES-DPH/ANB-1, at 51-52; ES-MPS-1, at 11-13).

at 41). The Attorney General notes that the 2018 cost per employee of $14,799 was by far the highest amount in the last four years, was 12.1 percent higher than the $13,198 average for the period of 2016 through 2019, and was 18.4 percent higher than the 2019 cost per employee of $12,504 (Attorney General Brief at 41, citing Exhs. AG 1-51; AG 1-51 (Supp.)). Thus, according to the Attorney General, the 2018 cost per employee that the Company uses to establish its pro forma increase to its test-year medical expenses is over-inflated and fails to account for the actual health care costs that the Company incurred (Attorney General Brief at 41).

Based on these arguments, the Attorney General contends that the actual 2019 cost per employee is more representative of the Company's actual incurred costs than the 2018 cost per employee that the Company used to calculate its pro forma adjustment (Attorney General Brief at 42, citing Exhs. AG 1-51; AG 1-51 (Supp.)). Thus, the Attorney General asserts that the Company's pro forma adjustment for medical expenses is neither known nor measurable because the record demonstrates a decrease in costs, as opposed to the increase that the Company forecasted and used for its proposed pro forma adjustment (Attorney General Brief at 42). As a result, the Attorney General recommends that the Department deny the Company's pro forma adjustment for medical expense (Attorney General Brief at 42).

ii. Company

The Company contends that the working rate calculation in this case is consistent with working rates approved by the Department in other proceedings (Company Brief at 316, citing D.P.U. 15-155, at 175; D.P.U. 17-05, at 152; D.P.U. 17-170, at 102; D.P.U. 18-150, at 239). Specifically, the Company notes that the working rates were designed with the support of consultants that employed an underwriting process to make projections for the upcoming year and that working rates vary from year to year based on the actual usage of the employees (Company Brief at 316, citing Exh. ES-MPS-1, at 11; Tr. 8, at 1207).

The Company reasons that, even though actual medical claims in 2018 were higher than the claims in 2019, there is no basis to conclude that the lower claim rate in 2019 will continue in the future, as working rates are derived on the basis of many factors and not just a comparison to other years' claim levels (Company Brief at 316). Moreover, the Company argues that its consultants reviewed Eversource Energy's own claims as well as national trend data in order to determine working rate trends and that these working rates represent a more holistic view of the market beyond the trends between comparing two years as the Attorney General recommends (Company Brief at 316-317). Further, NSTAR Gas asserts that the working rates used to calculate the adjustment are correlated to its own experience rather than that of a broad-based pool of insured entities (Company Brief at 304). Based on these considerations, NSTAR Gas maintains that the Department should accept the Company's proposed working rate (Company Brief at 317).

c. Analysis and Findings

To be included in rates, health care expenses, such as medical, dental, and vision, must be reasonable. The Berkshire Gas Company, D.T.E. 01-56, at 60-61 (2002); D.P.U. 92-78, at 29-30; Nantucket Electric Company, D.P.U. 91-106/91-138, at 53 (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; 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; 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's health care expenses are reasonable and that the Company has taken reasonable and effective measures to contain these costs (Exh. ES-MPS-1, at 6-15). First, Eversource is self-insured, which, when combined with other measures, tends to reduce costs (Exh. ES-MPS-1, at 11-12). Second, in an effort to effectively control increases in employee health care costs, the Company (1) introduced a High Deductible Health Plan design (the Saver plan) that encourages consumerism; (2) consolidated medical carriers and streamlined options to more efficiently extend health management programs; (3) negotiated an agreement with its pharmacy manager that resulted in discounts for prescription drugs, lower fees, and larger rebates; (4) employs a number of utilization-management programs such as step therapy programs that encourage the use of lower-cost generic medications; (5) uses quantity-limit programs that utilize the U.S. Food and Drug Administration guidelines regarding dosage limits; (6) applies prior-authorization programs that require clinical evidence before filling certain higher-cost and higher-risk medications; (7) uses mail order for maintenance drugs to generate savings associated with the elimination of dispensing fees; (8) explores opportunities for additional savings through health education, disease management programming, and regular assessment of vendor pricing; and (9) as of January 1, 2019, uses Blue Cross and Blue Shield of Massachusetts for the administration of its self-insured medical and prescription drug programs, which saved approximately $250,000 in 2019 and is reflected in the proposed working rate (Exhs. ES-MPS-1, at 7-10; AG 24-6).

Third, NSTAR Gas employs pricing strategies that encourage employees to consider lower-cost health-plan options and encourages its employees to evaluate alternate health-plan coverage available to employed family members (Exhs. ES-MPS-1, at 13; AG 1-52). The Company's non-represented employees pay a lower percentage of their own premium cost and a higher percentage of premiums for dependents, and they bear the cost of buying a higher level of coverage (Exh. ES-MPS-1, at 13-14). Likewise, NSTAR Gas offers opt-out credits to employees who have alternative health care coverage and opt out of the Company's plans at a fraction of the cost that would otherwise be required to provide health care coverage for those employees (Exhs. ES-MPS-1, at 7; AG 1-52). Additionally, the Company periodically benchmarks its health care benefit programs against the programs of other employers (Exh. ES-MPS-1, at 5). Finally, the Company offers wellness programs to help manage and improve employee health, reduce the demand for healthcare through healthy living, health education and chronic condition management, weight and stress management programs, and workplace ergonomics and injury prevention that, in turn, help to moderate health costs over time and reduce future health claims (Exhs. ES-MPS-1, at 14-15; AG 1-52).

The Company maintains that it has relied on the most recent working rates to develop the appropriate adjustments to test-year costs to reflect the increases that are expected in the rate year (Exhs. ES-DPH/ANB-1, at 51-52; ES-MPS-1, at 12-13; AG 24-6, at 2). The Department has previously denied recovery of pro forma health care expenses based on working rates derived from actuarial estimates encompassing a broad-based pool of insured parties. D.P.U. 15-80/D.P.U. 15-81, at 137; D.P.U. 13-90, at 94. In the instant case, however, NSTAR Gas's working rate is derived using Company-specific data, such as medical and prescription drug claims expense, enrollment figures, plan design details, administration costs, and fees (Exhs. ES-DPH/ANB-1, at 51-52; ES-MPS-1, at 10-13; ES-MPS-2; AG 24-6, at 2). The Company's third-party benefits consultant developed the working rate using actuarial principles; the rate is based on the Company's actual insurance claims and cost trends experienced during the two years prior to the renewal year (i.e., August 2017 – July 2018 and August 2018 – July 2019) (Exhs. ES-MPS-1, at 12-13; AG 24-6, at 2). Therefore, the Department concludes that NSTAR Gas's proposed working rate is appropriately correlated to the Company's own experience, rather than that of a broad-based pool of insured entities, to make it sufficiently reliable to warrant its use in determining the Company's health care expense in this proceeding.[101] D.P.U. 18-150, at 241-242; D.P.U. 17-170, at 103; D.P.U. 17-05, at 154; D.P.U. 15-155, at 176-177.

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101 The Department recognizes that disallowing NSTAR Gas's post-test year adjustments on the basis of working rates could provide a disincentive for companies to implement aggressive cost control measures, such as switching to self-insurance, when such measures otherwise would be deemed cost-effective. D.P.U. 15-155, at 177; D.P.U. 95-40, at 26; D.P.U. 92-210, at 22. However, we reiterate that working

Based on the above considerations, the Department approves the Company's proposed employee benefits expense of $6,226,362 (Exhs. ES-DPH/ANB-1, at 51-52; ES-MPS-2; ES-DPH/ANB-2 (Rev. 3), Sch. 14, at 2).

7. Post-Test Year Full-Time Employees

a. Introduction

The Company proposes to hire 89 post-test year full-time employees ("FTEs") to support its gas operations and cyber security functions (Exh. ES-WJA/DPH-1, at 39-55). The increased staffing would be in the following areas: 32 FTEs in its Gas Operations group; 34 FTEs in its Engineering Division; nine FTEs in its Pipeline Safety and Quality Assurance and Quality Control group (collectively referred to as "non-cyber-related FTEs"); and 14 employees in its IT Cyber Security group (referred to as "cyber-related FTEs"), for a total of 89 proposed post-test year FTEs (Exhs. ES-WJA/DPH-1, at 39-55; ES-DPH/ANB-1, at 46-48). NSTAR Gas states that these positions are needed to support the unprecedented level of capital deployment driven by the need to replace aging infrastructure at an accelerated pace, to comply with the rigorous state and federal regulatory requirements implemented post-Merrimack Valley incident, and to detect and respond to cyber security threats to the critical infrastructure of the Company (Exhs. ES-WJA/DPH-1, at 36-37; ES-DPH/ANB-1, at 46-47). The Company initially proposed to include estimated costs for all 89 proposed FTEs, for a total expense adjustment of $2,377,765 (Exhs. ES-DPH/ANB-1,

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rates must be correlated to the petitioner's experience, rather than that of a broad-based pool of insured entities.

at 47-48; DPH/ANB-2, Sch. 11, at 1). The Company subsequently revised its proposal to seek recovery of actual costs associated with the 60 FTEs hired as of the close of the record plus estimated costs for the remaining 29 FTEs not yet hired (Exh. DPH/ANB-2, Sch. 11, at 1 (Revs. 1-3)). The Company reduced its proposed total expense adjustment to $1,654,870, which comprises the following costs components: (1) $1,230,916 in payroll expense; (2) $64,626 in variable compensation expense; (3) $202,996 in health care expense; (4) $87,148 in vehicle expense; and (5) $69,183 in 401(k) expense (Exh. ES-DPH/ANB-2 (Rev. 3), Sch. 11).

b. Positions of the Parties

i. Attorney General

The Attorney General argues that the post-test year FTE hires have not resulted in and will not result in an increase to the number of employees outside the normal changes associated with the ongoing ebb and flow of employee levels (Attorney General Brief at 26; Attorney General Reply Brief at 11). The Attorney General maintains that Department precedent, specifically the recent decision in D.P.U. 17-170, establishes that the proposed FTE increase is not outside of the normal ebb and flow of employee levels (Attorney General Brief at 27; Attorney General Reply Brief at 11). She notes that in D.P.U. 17-170, the Department compared the proposed FTE increase to the entire National Grid complement of over 7,000 employees (inclusive of service company employees) in its determination of whether there was a significant post-test year change in the number of employees that fell outside the normal ebb and flow of the company’s workforce (Attorney General Brief at 27, citing D.P.U. 17-170, at 77-78; Attorney General Reply Brief at 11, citing D.P.U. 17-170, at 80 n.51; Exh. AG-DJE-Surrebuttal-1, at 2-3).

The Attorney General rejects the Company's claim that "the appropriate subset of employees to use when determining whether the FTE increase is significant is the combination of NSTAR Gas employees and the portion of ESC employees who report to [Company president] Mr. Akley and are dedicated to supporting the Company's gas operations" (Attorney General Brief at 27, citing Exh. ES-RR/CPP-Rebuttal-1, at 5; Attorney General Reply Brief at 10). She notes that NSTAR Gas failed to cite to any precedent where the Department utilized such a subset of employees in determining whether an FTE increase was outside the normal ebb and flow of employee levels (Attorney General Brief at 27-28; Attorney General Reply Brief at 10-11). Further, the Attorney General argues that the Company's proposal would result in a new standard for evaluating employee levels that would so narrowly define the relevant subset of employees that no proposed FTE increase would ever be found to be within the normal ebb and flow of the workforce complement (Attorney General Brief at 28, citing Exh. AG-DJE-Surrebuttal-1, at 3).

Moreover, the Attorney General takes issue with the Company's attempts to distinguish the facts of this case from D.P.U. 17-170 by claiming that the additional FTEs are necessary to ensure the safety and integrity of the distribution system (Attorney General Reply Brief at 11). According to the Attorney General, National Grid's request for post-test year additional FTEs in D.P.U. 17-170 was directly linked to the performance of leak detection work and work that was critical to the delivery of safe and reliable service

(Attorney General Reply Brief at 11, citing D.P.U. 17-170, at 77). Therefore, according to the Attorney General, there is no material distinction between the Company's post-test year cost recovery request here and that made by National Grid in D.P.U. 17-170 (Attorney General Reply Brief at 11, citing D.P.U. 17-170, at 77).

The Attorney General does not dispute that the positions in question are necessary, productive, or whether they are being filled (Attorney General Reply Brief at 10). Rather, the Attorney General reiterates that the expenses associated with these FTEs are not outside the normal ebb and flow of revenues and expenses that take place over time (Attorney General Reply Brief at 10, citing The Berkshire Gas Company, D.P.U. 90-121, at 80-81 (1990); Fitchburg Gas and Electric Light Company, D.P.U. 1270/1414, at 16-17 (1983)). Based on these considerations, the Attorney General maintains that the Department should eliminate the Company's proposed pro forma adjustment for payroll costs associated with the additional FTEs (Attorney General Brief at 26, 28; Attorney General Reply Brief at 11).

ii. Company

The Company argues that the Department should reject the Attorney General's recommendation because it is dismissive of the current operating environment and the impacts of the Merrimack Valley incident (Company Brief at 118). NSTAR Gas explains that the proposed FTEs are needed to support its field operations in maintaining the integrity of the distribution system and to support the Pipeline Safety Management System and cybersecurity functions in light of the new knowledge and perspective gained in the aftermath of the Merrimack Valley incident and the resulting new internal and external operational, safety, and regulatory requirements (Company Brief at 119, citing Exhs. ES-DPH/ANB-1, at 46; ES-RR/CPP-Rebuttal-1, at 6; DPU-ES 23-14; DPU-ES 23-24; DPU-ES 23-25; DPU-ES 34-4; DPU-ES 34-5; Tr. 8, at 1137-1138; Company Reply Brief at 60-61, citing Exhs. ES-WJA/DPH-1, at 39, 45, 53; DPU-ES 23-17). The Company notes that none of the positions in Gas Operations and Gas Engineering are needed to fill vacancies due to retirements, resignations, terminations, or transfers (Company Brief at 119). In addition, NSTAR Gas states that all of the FTEs will be hired to fill new positions, which the Company claims constitutes an institutional change within the organization (Company Brief at 119, citing Exhs. DPU-ES 23-17; DPU-ES 23-24; DPU-ES 34-4).

Further, the Company argues that the Merrimack Valley incident occurred at the end of the Department's proceeding in D.P.U. 17-170, and, therefore, does not provide the Department with a basis for denying these costs in an environment where public safety is driving institutional changes for gas companies (Company Brief at 119-120). The Company explains that the proposed positions would not have been created but for the Merrimack Valley incident (Company Reply Brief at 60, citing Exhs. ES-WJA/DPH-1, at 39-55; DPU-ES 23-17). Therefore, according to NSTAR Gas, these positions are outside the normal ebb and flow of revenues and expenses because new initiatives and changes occurring in the gas industry due to the Merrimack Valley incident encompass a "one-off" direct impact that the Company has never experienced before (Company Reply Brief at 59-60).

Moreover, the Company contends that the Attorney General's claim that the FTE proposal in D.P.U. 17-170 also was related to leak detection and safety is misplaced (Company Reply Brief at 61). NSTAR Gas contends that National Grid's base distribution rate case occurred prior to the Merrimack Valley incident and, unlike National Grid, the Company's FTE hires were in response to the knowledge and perspective gained from that event and not as a means to continue its normal operations (Company Reply Brief at 61, citing Exh. DPU-ES 23-24).

Further, NSTAR Gas asserts that the FTEs will be dedicated to gas operations and cyber security, and, therefore, the appropriate subset of employees to use when determining whether the FTE increase reaches a level of significance is the combination of NSTAR Gas employees and ESC gas operations employees who report directly to the Company's president, William J. Akley (Company Brief at 120, citing Exhs. ES-DPH/ANB-1, at 46; ES-RR/CPP-Rebuttal-1, at 6; DPU-ES 23-14; DPU-ES 23-24; DPU-ES 23-25; DPU-ES 34-4; DPU-ES 34-5; Tr. 8, at 1137-1138; Company Reply Brief at 60-61, citing Tr. 8, at 1147-1148). According to the Company, this increase is significant to the specific subset of employees that report to Mr. Akley, which cannot be considered within the normal ebb and flow of employee levels (Company Reply Brief at 61, citing Exhs. ES-RR/CPP-Rebuttal-1, at 7; DPU-ES 13-2; Tr. 8, at 1147-1148).

Finally, the Company claims that the Department should approve its FTE proposal given its commitment to a five-year stay-out as part of its proposed PBR plan (Company Brief at 120). NSTAR Gas argues that the proposed FTEs are necessary for the achievement of its critical public service obligations over the next five years in the context of industry dynamics, which will require the Company to strive for the "utmost level of public safety and reductions in methane emissions" (Company Brief at 121, citing Exhs. ES-DPH/ANB-1, at 46; ES-RR/CPP-Rebuttal-1, at 6, 15-16; DPU-ES 23-14; DPU-ES 23-24; DPU-ES 23-25; DPU-ES 34-4; DPU-ES 34-5). In the event that the Department were to deny its proposal, the Company maintains that it will not have the option of filing a base distribution rate proceeding to capture the costs associated with these FTEs as payroll and benefits costs escalate over time (Company Brief at 121).

Based on all of the above considerations, NSTAR Gas asserts that its FTE proposal should be approved, and the Attorney General's recommendations should be rejected (Company Brief at 121; Company Reply Brief at 62).

c. Analysis and Findings

The Department has recognized that employee levels routinely fluctuate because of retirements, resignations, hirings, terminations, and other factors. D.P.U. 88-172, at 12; Fitchburg Gas and Electric Light Company, D.P.U. 1270/1414, at 16-17 (1983). In recognition of this variability, the Department generally determines payroll expense on the basis of test-year employee levels, unless there has been a significant post-test year change in the number of employees that falls outside the normal ebb and flow of a company's workforce. D.P.U. 90-121, at 80-81; D.P.U. 88-172, at 12.

The Company states that it requires an additional 89 FTEs to support its gas operations and cyber security functions (Exhs. ES-WJA/DPH-1, at 39-55; ES-DPH/ANB-1, at 46-48). NSTAR Gas states that these positions are needed to support the unprecedented level of capital deployment driven by the need to replace aging infrastructure at an accelerated pace, to comply with the rigorous state and federal regulatory requirements implemented post-Merrimack Valley incident, and to detect and respond to cyber security threats to the critical infrastructure of the Company (Exhs. ES-WJA/DPH-1, at 36-37; ES-DPH/ANB-1, at 46-47).

The Department first considers whether the Company has demonstrated that the costs related to the post-test year FTEs are known and measurable. D.P.U. 17-170, at 79. As of the close of the record, NSTAR Gas had hired 60 of the 89 post-test year FTEs (RR-DPU-30, Att.). Of these hires, 51 are non-cyber-related FTEs and nine are cyber-related FTEs (RR-DPU-30, Att. at 2). Further, the Company has provided the labor and benefit costs associated with these 60 hires (RR-DPU-32 & Atts.). As such, the Department finds that the costs associated with the 60 FTEs who were hired before the close of the record in this proceeding are known and measurable. The Company has not demonstrated that the remaining 29 FTEs were hired prior to the close of the record. Therefore, the costs for the remaining 29 FTEs are not known and measurable and, as such, we will not consider them for recovery in the Company's cost of service.

Next, we consider whether the 60 FTEs whose costs we found to be known and measurable fall outside the normal ebb and flow of the Company's workforce. D.P.U. 90-121, at 80-81; D.P.U. 88-172, at 12. In this regard, the Company argues that, because the FTEs will be dedicated to gas operations and cyber security, it is appropriate to consider the FTEs as a subset of employees who report directly to Mr. Akley (Company Brief at 120, citing Exhs. ES-DPH/ANB-1, at 46; ES-RR/CPP-Rebuttal-1, at 6; DPU-ES 23-14; DPU-ES 23-24; DPU-ES 23-25; DPU-ES 34-4; DPU-ES 34-5; Tr. 8, at 1137-1138; Company Reply Brief at 60-61, citing Tr. 8, at 1147-1148). Viewed in this light, the Company asserts that the proposed FTEs represent a significant increase to the number of employees who report to Mr. Akley and, as such, they cannot be considered within the normal ebb and flow of employee levels (Company Reply Brief at 61, citing Exhs. ES-RR/CPP-Rebuttal-1, at 7; DPU-ES 13-2; Tr. 8, at 1147-1148).

The Department is not persuaded by the Company's argument. Rather, we will measure the proposed post-test year increase in employee count against the complement of test-year-end NSTAR Gas and ESC employees. See, e.g., D.P.U. 17-170, at 80 & n.51; D.P.U. 15-155, at 160-161. At the end of the test year, there were 366 NSTAR Gas FTEs and 2,808 ESC FTEs, for a total of 3,174 FTEs (Exh. AG 1-44, Att.). When comparing the 60 FTEs to the test-year-end total employee count for NSTAR Gas and ESC of 3,174, the increase is less than two percent. The Department finds that neither the number of proposed FTEs (i.e., 60) nor the percentage change in employee levels is outside the normal ebb and flow of hirings, retirements, resignations, or departures.[102]

The Department has allowed adjustments for post-test year changes to employee levels when they are associated with a permanent change to a company's structure and organization.

102 We would reach the same conclusion even if we considered the costs associated with all 89 proposed FTEs for inclusion in rates.

See, e.g., D.T.E. 01-56, at 58; D.P.U. 88-172, at 12. On brief, the Company argues that the proposed non-cyber-related FTEs are new positions that constitute “an institutional change within the organization” (Company Brief at 119, citing Exhs. DPU-ES 23-17; DPU-ES 23-24; DPU-ES 34-4). We are not persuaded, however, that the Company’s overall structure or organization has changed in a way that would support an adjustment based on these considerations.

Typically, our analysis would end here with a denial of the Company’s requested post-test year adjustment. We find, however, that the circumstances of this case warrant a departure from our typical standard, and we conclude that an adjustment to the Company’s cost of service is appropriate. In particular, we recognize that the Merrimack Valley incident had a direct and profound impact on the gas distribution industry. Among other things, the incident required NSTAR Gas to reexamine standards, practices, protocols, and procedures to ensure the safety and reliability of its gas distribution system and created enhanced safety requirements for the Company imposed through legislation and regulation (Exhs. ES-WJA/DPH-1, at 11, 34, 37; DPU-ES 23-15 & Atts.). We find that the Company has provided convincing evidence that the non-cyber-related FTE positions have been created[103] to support the increased field work associated with maintaining the safety and integrity of the distribution system, responding to increasing regulatory requirements and

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103 None of the positions proposed in the Gas Engineering, Gas Operations, and Pipeline Safety and Quality Assurance/Quality Control groups are needed to fill vacancies due to retirements, resignations, terminations or transfers; they are all new positions (Exhs. DPU-ES 23-17; DPU-ES 23-24; DPU-ES 34-4).

increasingly formalized coordination and risk management processes, and supporting the Pipeline Safety Management System (Exhs. ES-WJA/DPH-1, at 39-55; DPU-ES 23-17; DPU-ES 34-4; Tr. 8, at 1136-1139; 1146-1148). We recognize that these general areas of work have long been necessary to the safety and integrity of the Company's distribution system as well as the work performed on that system. The Merrimack Valley incident and its aftermath, however, have put additional requirements on the Company to ensure safety (Exhs. DPU-ES 23-17; DPU-ES 34-4; Tr. 8, at 1137-1139). Thus, we conclude that the proposed increase in non-cyber-related staffing levels is directly associated with the Company's response to the Merrimack Valley incident (Exhs. DPU-ES 23-24; DPU-ES 23-17; DPU-ES 34-4; Tr. 8, at 1137-1139).

In reaching this determination, we are not persuaded by the Attorney General's attempt to analogize the Company's proposal with National Grid's proposal in D.P.U. 17-170, and her claim that there is no material distinction between the two proposals (Attorney General Reply Brief at 11, citing D.P.U. 17-170, at 77). In particular, the Merrimack Valley incident occurred approximately two weeks before the Order was issued in D.P.U. 17-170, and, therefore, National Grid's request was not related to or evaluated in light of that incident and its impact on gas operations, safety and reliability, and regulatory requirements. In contrast, as we determined above, the Company's proposal to hire new non-cyber-related FTEs is directly associated with additional work resulting from the Merrimack Valley incident, a circumstance that was not present in D.P.U. 17-170, and not associated with the continuation of normal operations (Exhs. DPU-ES 23-24; DPU-ES 23-17;

DPU-ES 34-4; Tr. 8, at 1137-1139). Therefore, we find that the basis for NSTAR Gas's request in the instant proceeding is materially different from National Grid's proposal in D.P.U. 17-170.

Unlike the proposed non-cyber-related FTEs, the nine FTEs hired as of the close of the record in the Company's Cyber Security group do not serve the purpose of directly supporting the integrity of the distribution system. Rather, they are needed to detect and respond to cyber security events and to improve security monitoring of corporate and operational networks (Exhs. ES-DPH/ANB-1, at 46-47; DPU-ES 23-17; DPU-ES 34-4). While we recognize that these are important objectives, we find that the increase in staffing of the Cyber Security group is not directly related to the Merrimack Valley incident (Exhs. DPU-ES 23-17). Consequently, and for the reasons stated above, we do not allow recovery of the costs associated with the nine FTEs hired in the Cyber Security group.

Based on all of the above considerations, the Department will allow the Company to recover costs associated with the 51 non-cyber-related FTEs hired as of the close of the record. The record contains component payroll and benefits information concerning the proposed 51 FTEs, as well as allocation and capitalization percentages, but it does not provide overall costs (i.e., adjusted for allocations and capitalization) specifically associated with only the 51 non-cyber-related FTEs (see, e.g., RR-DPU-32 & Atts. (a)-(e)). The Department calculates the costs associated with the 51 FTEs as follows: (1) $865,126 in payroll expense;[104] (2) $50,800 in variable compensation expense; (3) $135,258 in health care expense;[105] (4) $51,485 in vehicle expense;[106] and (5) $41,056 in 401(k) expense[107] for a total expense adjustment of $1,143,725 (Exh. ES-DPH/ANB-2 (Rev. 3), Sch. 11; RR-DPU-32, Atts. (b), (d), (f)). As noted above, the Company initially proposed a total expense adjustment of $2,377,765, and subsequently revised the adjustment to $1,654,870 (Exhs. ES-DPH/ANB-1, at 47-48; ES-DPH/ANB-2, Sch. 11 (Revs. 1-3)). Accordingly, the Department further reduces the Company's proposed cost of service by $511,145 ($1,654,870-$1,143,725).

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104 In calculating the payroll and variable compensation expense, the Department removed actual and estimated costs associated with the cyber-related FTEs, as well as estimated costs for six 2020 union FTE hires and 18 ESC FTE hires (Exh. ES-DPH/ANB-2 (Rev. 3), Sch. 11, at 2-3; RR-DPU-32, Atts. (b), (d), (f)).

105 The Department was not able to derive a precise calculation for health care expense associated solely with the allowed 51 FTEs from the documentation provided in Record Request DPU-32, Att. (f) at 4. As such, the Department calculates health care expense at 51/60th of the total amount of $159,128 provided in the response to Record Request DPU-32.

106 This amount reflects the vehicle expense associated with employees hired as of the close of the record (Exh. ES-DPH/ANB-2 (Rev. 3), Sch. 11, at 5; RR-DPU-32(f)).

107 The Department was not able to derive a precise calculation for 401K expense associated solely with the allowed 51 FTEs from the documentation provided in the Company's response to Record Request DPU-32, Attachment (f) at 6. As such, the Department calculated 401K expense by removing the forecasted amounts and calculating 51/60th of the total actual amount of $48,301 provided in this Record Request response.

8. Payroll Taxes

a. Introduction

During the test year, NSTAR Gas booked $2,966,349 in payroll taxes for the test year (Exh. ES-DPH/ANB-2 (Rev. 3), Sch. 25). NSTAR Gas proposes to increase payroll tax expense by a total of $465,483, for the following: (1) $113,582 for the Federal Insurance Contribution Act; (2) $46,934 for the Medicare payroll tax expense based on the increase in test-year labor charges through the mid-point of the rate year; (3) $204,842 for the Family and Medical Leave Act tax; and (4) $100,125 in payroll taxes associated with the Company's proposed post-test year FTEs (Exhs. ES-DPH/ANB-1, at 119; ES-DPH/ANB-2 (Rev. 3), Sch. 25).

b. Positions of the Parties

The Company states that that it has adhered to the Department's standards regarding taxes other than income taxes, and, therefore, the Department should approve the Company's calculation of payroll tax expense (Company Brief at 259). No other party addressed this issue on brief.

c. Analysis and Findings

The Department has examined the record related to the Company's payroll tax calculations (Exh. ES-DPH/ANB-2 (Rev. 3), Sch. 25). Revisions to the Company's proposed payroll tax adjustments are necessary. In Section VIII.A.7c, above, the Department allowed costs related to 51 of the Company's estimated 89 FTEs hired post-test year. As such, the Company's proposed payroll tax increase of $100,125 is adjusted by

51/89ths for a $57,375 allowance of payroll tax expense. Accordingly, the Department will reduce the Company's proposed cost of service by $42,750 ($100,125 - $57,375).

B. Enterprise Information Technology Projects Expense

1. Introduction

Enterprise Information Technology ("IT") projects expense represents charges billed to NSTAR Gas for ESC's investments in IT systems that support more than one of the Eversource operating companies and are installed at the service company level for efficiency (Exh. ES-DPH/ANB-1, at 54-55). Accordingly, Enterprise IT projects are capitalized by ESC and charged to the operating companies as expense through the general service company overhead rate (Exh. ES-DPH/ANB-1, at 32-33, 54). ESC's revenue requirement for the Enterprise IT projects is composed of depreciation expense and a return on ESC's gross investment base less accumulated depreciation and accumulated deferred income taxes ("ADIT") (Exhs. ES-DPH/ANB-2 (Rev. 3), Sch. 15; ES-DPH/ANB-4 (Rev. 2), Sch. 6). The ESC then applied an allocation percentage of 55.77 percent to determine the amount of expense allocable to NSTAR Gas, which was based on the Company's proportionate share of the total number of gas customers serviced by NSTAR Gas and by Yankee Gas Services Company ("Yankee Gas") combined (Exh. ES-DPH/ANB-1, at 61-62). Finally, the ESC employees perform both capital and expense functions for the Company related to the Enterprise IT projects; therefore, the ESC expense ratio of 66.50 percent was applied against the total cost for NSTAR Gas, with the remainder charged to capital or other balance sheets accounts and not included in the NSTAR Gas expense computation (Exhs. ES-DPH/ANB-1, at 62; ES-DPH/ANB-2, Sch. 15; ES-DPH/ANB-4, Sch. 6).

In its initial filing, the Company presented an adjusted, test-year Enterprise IT projects expense of $4,277,364[108] and a proposed pro forma increase of $2,732,339 based on the total estimated revenue requirement associated with three post-test year Enterprise IT projects: the Work and Asset Management ("WAM") project; the deployment of ClickSoftware mobile technology ("Mobile Gas WAM"); and the Mobile Gas Meter Services ("MGMS") project, for a total proposed Enterprise IT projects expense of $7,009,703 (Exhs. ES-DPH/ANB-1, at 55; ES-DPH/ANB-2, Sch. 15, at 1; ES-LML/TCD-1, at 39). During the proceeding, the Company revised its proposed Enterprise IT projects expense to $9,341,590 based on (1) a revised calculation of ESC's return on the test-year and post-test-year investments to reflect a recent debt issuance by the Company and NSTAR Gas's proposed weighted average cost of capital ("WACC") and (2) an update to the actual costs for the three post-test year Enterprise IT projects (Exhs. ES-DPH/ANB-2 (Rev. 3), Sch. 15; ES-DPH/ANB-4 (Rev. 2), Sch. 6; DPU-ES 1-2 (Rev.) & Att. (a)).

2. Positions of the Parties

a. Attorney General

The Attorney General maintains that the Company is responsible for developing a record sufficient to support a Department decision in favor of approving the proposed Enterprise IT projects expense (Attorney General Brief at 46-47). The Attorney General further contends that under the Department's standard of review for affiliate IT investments,

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108 The adjusted test-year expense represented the revenue requirement associated with ESC's capital costs computed using the return on equity proposed for NSTAR Gas in this proceeding (Exh. DPU-ES 1-2(c)-(d)).

the Company must provide clear and cohesive reviewable evidence to support findings that the investments are used and useful, the costs of the investments were prudently incurred, and that the costs of the investments are fairly allocated to the Company (Attorney General Brief at 46-47).

The Attorney General argues that the Department must disallow the Company's proposed pro forma increase to Enterprise IT projects expense because the Company provided insufficient project documentation to verify in-service dates for the post-test year Enterprise IT projects and, thus, to support a finding that the projects are used and useful to ratepayers (Attorney General Brief at 45, 47; Attorney General Reply Brief at 14-15). Specifically, the Attorney General insists that the evidence critical to the Company's proof includes screen shots from the Company's work management system providing a time stamp of when the stages of a work order are finished and closing reports, neither of which were provided by the Company in response to the Attorney General's inquiry on this issue (Attorney General Brief at 48-49, citing Exhs. AG-FWR-Surrebuttal-1, at 7-9; AG 40-1; AG 40-4; AG 40-5; AG 40-7; AG 40-9; AG 46-14, Att.). The Attorney General asserts that the Company has failed to support its reason for not providing the screen shots in question as record evidence (Attorney General Reply Brief at 15). Moreover, the Attorney General claims that the Company's multiple record updates for costs spent on the projects are clear evidence that the reports provided by the Company are spending reports not closing reports (Attorney General Brief at 48-49, citing Exhs. ES-LML/TCD-11, at 58; DPU-ES 6-5 (Supp. 2), Att. (a); AG 40-1(vi); AG 42-2; Attorney General Reply Brief at 15-16).

Finally, the Attorney General avers that the Company failed to recognize corresponding O&M expense savings realized as a result of the Enterprise IT investments (Attorney General Brief at 50; Attorney General Reply Brief at 16). The Attorney General maintains that the Company should not be allowed to pass on the costs of Enterprise IT projects to ratepayers while keeping all of the cost savings that the Company listed as a justification for the investments (Attorney General Brief at 49-50, citing Exhs. AG-FWR-Surrebuttal-1, at 10-11; ES-RR/CPP-Rebuttal-1, at 24-27; ES-LML/TCD-11, at 71, 185; Attorney General Reply Brief at 16).

b. Company

The Company summarizes the issues with the legacy IT systems; ESC's decision-making process in moving forward with the WAM, Mobile Gas WAM, and MGMS projects; and the benefits of the new IT investments to the Company and ratepayers (Company Brief at 334-341). The Company contends that it provided project documentation for all of the Enterprise IT projects consistent with the Department's directives in D.P.U. 18-150, including, but not limited to, initial and supplemental PAFs, project strategy assessments, request for proposals ("RFP") process documentation, closing reports, and variance analyses (Company Brief at 340, citing Exhs. ES-LML/TCD-11, at 61, 64, 114, 128, 173, 177; DPU-ES 6-5; DPU-ES 6-5 (Rev.), DPU-ES 6-5 (Supp. 1), DPU-ES 6-5 (Supp. 2), DPU-ES 6-5 (Supp. 3); DPU-ES 6-7; AG 13-50; AG 25-2; AG 25-4; Company Reply Brief at 53). NSTAR Gas claims that all Enterprise IT projects were fully in service by May 31, 2020 (Company Brief at 340-341, citing Exh. DPU-ES 6-5(Supp. 3)).

Regarding the Attorney General's argument concerning the screen shots from the Company's work asset management system, NSTAR Gas asserts that it was unable to produce a screen shot because Enterprise IT projects are generated in a separate system and that the documentation provided by the Company is sufficient to support a finding that the projects are in service (Company Brief at 341, citing Exh. AG 40-1; Company Reply Brief at 53). With respect to the Attorney General's claim that the record lacks closing reports for the projects, NSTAR Gas explains that the work orders related to NSTAR Gas reflect final costs while the work orders related to IT projects for NSTAR Electric continue to receive charges as that work continues (Company Brief at 341-342, citing Exhs. ES-RR/CPP-Rebuttal-1, at 21-23; Tr. 12, at 1541-1548; Company Reply Brief at 54).

Lastly, NSTAR Gas argues that savings associated with the Company's Enterprise IT investments are not eligible for inclusion in the cost of service because they are not yet known and measurable (Company Reply Brief at 54, citing Exh. DPU-ES 6-1). NSTAR Gas maintains that the Department has consistently rejected proposed adjustments for savings when the savings are speculative (Company Reply Brief at 55, citing Massachusetts Electric Company/Nantucket Electric Company, D.P.U. 15-155, at 307 (2016); Bay State Gas Company, D.P.U. 13-75, at 114 (2014); Bay State Gas Company, D.T.E. 05-27, at 129-131 (2005); Boston Gas Company, D.T.E. 03-40, at 11 (2003)). NSTAR Gas alleges that the non-financial benefits of the projects will bring future cost savings to customers once they are known and measurable (Company Reply Brief at 55).

3. Standard of Review

The standard for the inclusion of IT expense is comprised of three elements.[109] First, the investments underlying the IT expense must be and used and useful. D.P.U. 18-150, at 274, citing D.P.U. 95-118, at 42. Second, the underlying IT investments must be prudently incurred. D.P.U. 18-150, at 274, citing D.P.U. 95-118, at 42. Third, the underlying IT investments must be fairly allocated to the company, with an explanation of how the company and its ratepayers benefit from the investment. D.P.U. 18-150, at 274-275, citing Hingham Water Company, D.P.U. 88-170, at 21 (1989); Housatonic Water Works Company, D.P.U. 86-93, at 18 (1987); see also Milford Water Company, D.P.U. 12-86, at 11 (the Department must carefully scrutinize affiliate transactions because the exercise of control and the absence of arm's-length bargaining between affiliated companies can lead to "excessive charges for services, construction work, equipment and materials") (citations omitted); Public Utility Holding Company Act of 1935, P.L. No. 333, 49 Stat. 803, § 1(b)(2), (3) (1935) (Congress recognized concern with allocation of costs within public utility holding company as reason for legislative/regulatory control of holding

109 Historically, the Department reviewed a petitioning company's proposed IT expense under the standard of review for lease expense (i.e., reasonableness), as the affiliated service company included IT expense in its lease charges to the petitioning company. D.P.U. 18-150, at 273; D.P.U. 15-155, at 308; D.P.U. 09-39, at 159-159. In D.P.U. 18-150, the Department found that, in conjunction with the increasing importance of IT in business functions, the size and scope of IT investments had become more significant and that this trend likely would continue. D.P.U. 18-150, at 272-273 & n.125. Based on these considerations, the Department found that the lease expense standard of review was no longer sufficient to satisfy the burden of proof necessary for IT-related expense. D.P.U. 18-150, at 273.

companies where subsidiary company accounting practices and rates are affected); Report of the Special Commission on Control and Conduct of Public Utilities (1930 H. 1200), at 46 (March 1930) (consumers suffer from excessive charges by affiliates to operating companies). In addition, as part of their initial filings requesting new base distribution rates, petitioning companies must submit the following documentation for each service-company-allocated IT investment: (1) project sanctioning papers; (2) project closure reports; (3) variance analyses explaining the reasons for cost overruns and for demonstrating prudency; (4) project descriptions, including completed analyses enumerating ratepayer benefits and the investment's advancement of company IT strategy; and (5) the company's long-term investment plan. D.P.U. 18-150, at 275. Petitioning companies are also required to amend their initial filing to include documentation associated with post-test year investments, if applicable. D.P.U. 18-150, at 275.

#### 4. Analysis and Findings

The Department has reviewed the testimony and documentation provided by the Company in its initial filing concerning the Enterprise IT projects as well as the updates provided during the proceeding. The Department finds that the Company provided project documentation and updates for post-test year investments in accordance with the filing requirements established in D.P.U. 18-150 (see, e.g., Exhs. ES-LML/TCD-1, at 38-52; ES-LML/TCD-11, Schs. 11B-11D; DPU-ES 6-5, Atts. (a)-(c); DPU-ES 6-5 (Supp. 3), Atts. (a)-(c); DPU-ES 6-6 & Att.; DPU-ES 6-6 (Supp. 2) & Att.).

The Attorney General argues that there is insufficient evidence to support a finding that the WAM, Mobile Gas WAM, or MGMS projects are in service because the Company did not provide screen shots of the IT projects' work orders in the asset management system (Attorney General Brief at 47-48, citing Exh. AG-FWR-Surrebuttal-1, at 5-9). The evidence demonstrates, however, that a screen shot of the Company's asset management system would provide the date a work order closed and that a work order may remain open because it continues to accrue charges though the project is in service, as was the case for the Enterprise IT projects because work remained ongoing to implement the investments for NSTAR Electric while the investments already had been deployed for NSTAR Gas (Exhs. DPU-ES 6-6; DPU-ES 6-6 (Supp. 2), Att.; AG 40-1; Tr. 12, at 1541-1542, 1547-1548). NSTAR Gas provided a report showing that the in-service dates for the WAM, Mobile Gas WAM, and MGMS were March 31, 2019, August 29, 2019, and May 29, 2020, respectively, and a reasonable explanation that the work orders associated with the IT investments were not closed (Exhs. DPU-ES 6-6; DPU-ES 6-6 (Supp. 2), Att.; AG 40-1; Tr. 12, at 1541-1542, 1547-1548). Further, the Department finds that the Company's timely updates to the actual costs incurred on these projects do not suggest that the projects are not in service; rather, the updates are consistent with the Department's requirement that petitioning companies update the documentation associated with post-test year IT investments. For these reasons, we find that there is substantial evidence that the WAM, Mobile Gas WAM, and MGMS are in service and thus used and useful to ratepayers.

The Department has reviewed the supporting documentation for the Enterprise IT investments, including initial and supplemental project authorization forms, descriptions of ratepayer benefits, and variance analyses (Exhs. ES-LML/TCD-11; DPU-ES 6-7, Att. (a); AG 13-50, Att.; AG 13-51; AG 16-4; AG 16-5; AG 24-10 & Att.; AG 24-11; & Att.; AG 24-12 & Att.; AG 25-4, Att.). We find that the Company provided a reasonable explanation of the benefits to the Company and ratepayers and the projects' cost variances, and we find that the project costs were prudently incurred. Further, we find that the Enterprise IT projects expense is fairly allocated to NSTAR Gas based on the Company's proportionate share of the total number of gas customers serviced by NSTAR Gas and Yankee Gas combined (Exhs. ES-DPH/ANB-1, at 61-62; AG 1-28, AG 13-42 & Att., AG 13-47, AG 13-48, AG 16-2).

In response to the Attorney General's issue with the lack of cost savings related to Enterprise IT project costs, the Department has previously rejected proposed adjustments for savings achieved by projects when the record showed the savings were speculative or there was uncertainty that savings would be achieved in the rate year. D.P.U. 15-155, at 307; D.P.U. 13-75, at 114. Although the Company has acknowledged that there should be opportunities for savings associated with the implementation of the Enterprise IT projects, these potential savings would be recognized in the future and are not known and measurable at this time (Exh. DPU-ES 6-1). Therefore, these savings are not currently quantifiable and are not included in the cost of service.

As summarized above, NSTAR Gas proposes an Enterprise IT Projects expense amount of $9,341,590, which includes an adjustment to test-year expense that calculates ESC's return using NSTAR Gas's proposed pre-tax WACC and a post-test year increase in the amount of $4,855,459, representing the amount allocated to NSTAR Gas by ESC for costs associated with the WAM Gas, Mobile Gas WAM, and MGMS (Exhs. ES-DPH/ANB-2 (Rev. 2), Sch. 15; DPU-ES 1-2 (Rev.) & Att. (a)). The proposed adjusted test-year expense consists of $2,147,053 for depreciation and a $2,339,079 return on investment that is calculated by applying the Company's proposed 9.76-percent, pre-tax WACC, 7.19-percent allocation rate, and 66.50-percent expense ratio to ESC's average rate base of $501,400,755 (Exhs. ES-DPH/ANB-2 (Rev. 3), Sch. 15; DPU-ES 1-2 (Rev. 1), Att. (a) at 3). ESC's proposed revenue requirement for the post-test year projects consists of $6,481,327 for depreciation expense and a return on investment of $6,658,765, which is calculated by applying the Company's proposed 9.76-percent, pre-tax WACC to an investment base of $68,225,056[110] (Exhs. ES-DPH/ANB-2 (Rev. 3), Sch. 15; ES-DPH/ANB-4, Sch. 6). Application of the 55.57-percent allocation factor and 66.50-percent expense ratio to ESC's revenue requirement of $13,140,092 yields the Company's proposed post-test year increase of $4,855,459 (Exh. ES-DPH/ANB-2 (Rev. 3), Sch. 15).

110 The investment base comprises $97,171,323 gross investment less $8,318,143 accumulated depreciation and less $20,628,124 ADIT.

In Section XI, below, the Department approved a pre-tax WACC of 9.33 percent.[111] For the adjusted test-year level of expense, applying the approved pre-tax WACC of 9.33 percent, 7.19-percent allocation rate, and 66.50-percent expense ratio to ESC's average rate base of $501,400,755 yields a return of $2,236,135, a decrease of $102,944 from the Company's proposal. For the post-test year investments, applying the approved pre-tax WACC of 9.33 percent to the investment base yields a return of $6,365,398[112] and a total revenue requirement of $12,846,725.[113] Application of the 55.57-percent allocation factor yields $7,138,925 assigned to NSTAR Gas, and application of ESC's 66.50-percent expense ratio yields a post-test year adjustment of $4,747,055 a decrease of $108,404[114] from the Company's proposal. Accordingly, the Department decreases the Company's proposed Enterprise IT projects expense by $211,348.[115, 116]

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111 The Department approved a capital structure of 45.23 percent long-term debt and 54.77 percent common equity. The Department approved a long-term debt cost of 4.13 percent and a ROE of 9.9 percent. Applying a tax gross-up using a combined federal and state tax rate of 37.59 percent on the common equity portion of the Company's capital structure, results in a pre-tax WACC of 9.33 percent.

112 $68,225,056 multiplied by 9.33 percent equals $6,365,398

113 $6,481,327 for depreciation expense plus a return of $6,356,398 equals $12,846,725

114 $4,855,459 minus $4,747,055 equals $108,404

115 $102,944 plus $108,404 equals $211,348

116 Minor discrepancies in any of the amounts appearing in this section are due to rounding.

C. Lease Expense

1. Introduction

During the test year, the Company booked $2,505,247 in lease expense associated with facilities in Boston, New Bedford, Plymouth, Somerville, and Westwood, Massachusetts as well as Berlin, Windsor, and Hartford, Connecticut (Exhs. ES-DPH/ANB-1, at 69-71; ES-DPH/ANB-2, Sch. 17, at 1-2). The Company proposed four adjustments to its test-year lease expense: (1) a $98,956 increase to intercompany rents paid to NSTAR Electric; (2) a $433,655 increase associated with the facility in Westwood, Massachusetts that is jointly owned by NSTAR Gas and NSTAR Electric; (3) a $2,246 increase for the lease of the Prudential Center in Boston, Massachusetts; and (4) a decrease of $257,303 for leased facilities owned by Rocky River in Berlin, Windsor, and Hartford Connecticut, resulting in a net increase to the lease expense incurred in the test year of $277,554 (Exhs. ES-DPH/ANB-1, at 69-71; ES-DPH/ANB-2, Sch. 17, at 1-2). The test-year lease expense included $34,617 for expenses allocated to NSTAR Gas associated with Eversource's use of property located at 56 Prospect Street in Hartford, Connecticut ("56 Prospect Street") (Exh. AG 41-1 & Att.).

In addition, the Company proposed a $1,884,135 increase in lease expense associated with a new facility—the Auburn AWC (Exhs. ES-DPH/ANB-1, at 71; ES-DPH/ANB-2, Sch. 17, at 2; ES-LML/TCD-1, at 52). The Company determined that it was most efficient and cost effective to relocate the existing gas service center in Worcester, Massachusetts, which housed about 100 employees, to a new facility because the current facility required significant investments to meet the Company's needs moving forward and the new facility allowed the Company to avoid needed improvements at area work centers in Auburn, Waltham, and Southborough, Massachusetts (Exh. ES-LML/TCD-1, at 52-53). The lease expense associated with the Auburn AWC is composed of depreciation expense, property taxes, and a return on the gross investment base less accumulated depreciation and ADIT (Exh. ES-DPH/ANB-4, Sch. 7, at 1). An allocated portion of the lease expense is assigned by Rocky River through ESC to each occupant based on square footage (Exh. ES-DPH/ANB-1, at 71-72).[117] To determine NSTAR Gas's allocated portion, ESC applied an allocation percentage of 75.07 percent and then an expense ratio of 66.50 percent (Exh. ES-DPH/ANB-4, Sch. 7). In sum, the aforementioned lease expense adjustments resulted in an initial proposed pro forma lease expense of $3,942,771 (Exhs. ES-DPH/ANB-1, at 69-72; ES-DPH/ANB-2, Sch. 17, at 1-2).

During these proceedings, the Company revised test-year lease expense to use the Company's proposed ROE, WACC, and depreciation rates (Exh. DPU-ES 1-10, Att. (a)). In addition, NSTAR Gas stated that Eversource had changed the scope of the Auburn AWC in response to two intervening events: (1) Eversource's planned acquisition of the Massachusetts assets of Bay State and (2) the outbreak of the COVID-19 pandemic (Exhs. AG 38-1 & Atts.; AG 38-2; AG 38-3; RR-DPU-8 (Supp.); Tr. 8, at 1039-1043). In light of the acquisition of Bay State's assets, Eversource determined that it was appropriate to

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117 NSTAR Gas is billed for its share of ESC's rent associated with the Auburn AWC pursuant to their service company agreement (Exh. ES-DPH/ANB-4, Sch. 2; Tr. 8, at 1048; RR-DPU-8).

remove the cost of the training facility portion of the Auburn AWC from its proposed lease expense while it evaluated whether a new training facility would be redundant with assets acquired from Bay State (Exh. AG 38-3). With respect to the COVID-19 pandemic, the Company explained that the removal of the training facility had changed the expected in-service date from December 2020 to June 2020 but that the effects of the pandemic on vendors and contractors had delayed the in-service date to September 15, 2020 (Exhs. AG 38-1, Atts.; AG 38-2; RR-DPU-8 (Supp.); Tr. 8, at 1039-1043).[118] On August 6, 2020, ESC executed a lease agreement with Rocky River with a one-year term commencing August 31, 2020 that automatically renews for consecutive one-year periods until terminated as provided in the lease agreement (RR-DPU-8 (Supp.), Att. at 1-2).

Subsequently, the Company filed a revised calculation of the proposed pro forma lease expense associated with the Auburn AWC to update the investment base, property taxes, return on investment, and expense ratio adjustment (Exhs. ES-DPH/ANB-2 (Rev. 3), Sch. 17; DPU-ES 1-10 (Rev. 1) & Atts.). NSTAR Gas proposed a final lease expense of $4,938,105, representing a $2,432,858 increase to the test-year lease expense (Exh. ES-DPH/ANB-2 (Rev. 3), Sch. 17).

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[118] Initially, the Company stated that the COVID-19 pandemic had delayed the in-service date to August 2020 (Exh. AG 38-2). The Company later explained that a delay in the installation of the facility's air conditioning unit due to the COVID-19 pandemic had pushed the in-service date to September 15, 2020 (RR-DPU-8 (Supp.)).

2. Positions of the Parties

a. Attorney General

The Attorney General alleges that the Company's proposal includes lease expense for corporate headquarters in both Hartford, Connecticut and Boston, Massachusetts (Attorney General Brief at 61). The Attorney General maintains that the Department should exclude all costs associated with 56 Prospect Street, Eversource's headquarters in Connecticut (Attorney General Brief at 61). The Attorney General avers that a second headquarters is clearly redundant and unnecessary for the provision of gas service[119] in the Commonwealth, so Massachusetts ratepayers should not be required to pay for costs associated with both facilities (Attorney General Brief at 61).

The Attorney General also argues that the Department should reject the Company's request to recover costs associated with the Auburn AWC because (1) the facility was not in-service and, thus, not used and useful at the close of evidentiary hearings and (2) the Department cannot rely on speculation that the facility will be in-service after the close of the record (Attorney General Brief at 52-54; Attorney General Reply Brief at 12). The Attorney General asserts that the Company has failed to meet its burden to prove the investments underlying the rent expense are in service (Attorney General Brief at 53; Attorney General Reply Brief at 12). Moreover, the Attorney General contends that the Auburn AWC lease expenses should be rejected because the facility's costs are speculative and not known and

[119] The Department recognizes the Attorney General's reference on brief to electric distribution service as a scrivener's error.

measurable where, as of the evidentiary hearings, nearly all planned renovations of the existing warehouse remained incomplete and the Company failed to clearly account for the elimination of the 30,000-square foot addition (Attorney General Brief at 54; Attorney General Reply Brief at 13). Specifically, the Attorney General claims that the total cost for the Auburn AWC still includes costs for items associated with the construction of the addition and the second level, despite the Company claiming in evidentiary hearings that the Company would no longer complete any element of the addition (Attorney General Reply Brief at 13, citing Exh. AG 38-1, Att.(d) at 1-2; Tr. 12, at 1552-1553, 1564-1565). Lastly, the Attorney General asserts that the Department should disallow the costs for the Auburn AWC because the Company has refused to offset the facility's costs with the expected savings and avoided costs in other areas of the Company's operations, which the Company repeatedly attested to on the record (Attorney General Brief at 55-56, citing Exhs. ES-DPH/ANB-1, at 73; ES-LML/TCD-1, at 53; ES-RR-CPP-Rebuttal-1, at 29; AG-L&A-Surrebuttal-16).

b. Company

The Company summarizes the pro forma adjustments to lease expense (Company Brief at 217-220). NSTAR Gas asserts that the pro forma adjustments reflect known and measurable changes in rent expense through the midpoint of the rate year (Company Brief at 217).

The Company alleges that the corporate headquarters at 56 Prospect Street are used by NSTAR Gas executives when working in Connecticut (Company Brief at 224).

Therefore, the Company claims that the costs are reasonable and appropriate to include in the Company's cost of service (Company Brief at 224).

The Company maintains that, although completion of the Auburn AWC has been delayed due to the need for enhanced safety precautions driven by the COVID-19 pandemic, the Auburn AWC will be occupied by NSTAR Gas employees by September 2020 (Company Reply Brief at 56, citing Exhs. ES-RR/CPP-Rebuttal-1, at 30; AG 38-2; Tr. 12, at 1550-1551; RR-DPU-8 (Supp.)). The Company alleges that only a couple of final items are required before NSTAR Gas can occupy the building (i.e., installation of an HVAC system and a fire loop repeater); that these items will be completed by September 15, 2020; and that as of that date, the Auburn AWC will be fully used and useful to customers (Company Brief at 344, citing Tr. 12, at 1551; Company Reply Brief at 57, citing RR-DPU-8 (Supp.)).

NSTAR Gas also objects to the Attorney General's contention that the costs of the Auburn AWC are not known and measurable (Company Brief at 345; Company Reply Brief at 58-59). First, the Company claims that the record fully explains and accounts for the removal of costs associated with the training facility (Company Brief at 345; Company Reply Brief at 58-59, citing Exh. ES-RR/CPP-Rebuttal-1, at 30; Tr. 12, at 1570-1572). Second, the Company maintains that the Department has consistently rejected proposed adjustments for savings associated with capital projects that are speculative or uncertain to accrue in the rate year (Company Reply Brief at 59, citing D.P.U. 15-155, at 307; Bay State Gas Company, D.P.U. 13-75, at 114; Bay State Gas Company, D.T.E. 05-27, at 129-13; Boston

Gas Company, D.T.E 03-40, at 11). NSTAR Gas insists that while there are opportunities for savings in the future, at this time the savings associated with the Auburn AWC are not known and measurable and, consistent with Department precedent, should not be included in the cost of service (Company Brief at 345, citing Exhs. ES-RR/CPP-Rebuttal-1, at 29; DPU-ES 6-10; Company Reply Brief at 59).

3. Analysis and Findings

a. Introduction

A company's lease expense represents an allowable cost qualified for inclusion in its overall cost of service. D.T.E. 03-40, at 171; Nantucket Electric Company, D.P.U. 88-161/168, at 123-125 (1988). The standard for inclusion of lease expense is one of reasonableness. Commonwealth Electric Company, D.P.U. 89-114/90-331/91-80 (Phase One) at 96 (1991). Known and measurable increases in lease expense based on executed lease agreements with unaffiliated landlords are recognized in cost of service as are associated operating costs (e.g., maintenance, property taxes) that the lessee agrees to cover as part of the agreement. Massachusetts-American Water Company, D.P.U. 95-118, at 42 n.24 (1996); Boston Gas Company, D.P.U. 88-67 (Phase I) at 95-97 (1988).

The Department permits rate recovery of payments to affiliates where those payments are: (1) for activities that specifically benefit the regulated utility and that do not duplicate services already provided by the utility; (2) made at a competitive and reasonable price; and (3) allocated to the utility by a formula that is both cost effective 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. 95-118, at 41, citing Milford Water Company, D.P.U. 92-101, at 42-46 (1992); AT&T Communications of New England, Inc., D.P.U. 85-137, at 51-52 (1985). In addition, 220 CMR 12.04(3) provides that,"[a]n Affiliated Company may sell, lease, or otherwise transfer an asset to a Distribution Company, and may also provide services to a Distribution Company, provided that the price charged to the Distribution Company is no greater than the market value of the asset or service provided."

b. 56 Prospect Street

As noted above, the Attorney General objects to the Company's inclusion of $34,617 in lease expense associated with 56 Prospect Street (Exhs. AG 1-29, Att.(b), AG 41-1, Att.). The Company bears the burden of demonstrating that the lease expense associated with 56 Prospect Street benefits Massachusetts ratepayers and is reasonable. D.P.U. 17-05, at 217. In that case, the Department excluded lease expense associated with 56 Prospect Street because NSTAR Electric and Western Massachusetts Electric Company ("WMECo") failed to produce any persuasive evidence that the corporate headquarters in Connecticut benefitted Massachusetts ratepayers. D.P.U. 17-05, at 217. On brief, NSTAR Gas has cited no evidence that supports its proposal to include the 56 Prospect Street expenses in the cost of service, and we simply cannot discern from the record any benefits to Massachusetts ratepayers associated with 56 Prospect Street. As such, the Department finds that the Company has failed to sustain its burden of demonstrating that this lease expense is reasonable. D.P.U. 17-05, at 217, citing Aquarion Water Company of Massachusetts, D.P.U. 08-27, at 32 (2009); Bay State Gas Company, D.T.E. 05-27, at 93-96 (2005); Phelps

v. Hartwell, 1 Mass. 71, 73 (1804)). Accordingly, the Department will reduce NSTAR Gas's proposed cost of service by $34,617.

c. Auburn AWC

As noted above, Eversource's affiliates Rocky River and ESC executed a lease on August 6, 2020 for the Auburn AWC, which commenced on August 31, 2020, for an initial one-year term and provided for annual automatic renewals until terminated by the parties (RR-DPU-8 (Supp.), Att. at 1-2). Pursuant to the lease, ESC agreed to pay rent to Rocky River based on Rocky River's costs to own, construct, operate, and maintain the Auburn AWC (RR-DPU-8 (Supp.), Att. at 2). In turn, NSTAR Gas has proposed to include in its cost of service the expenses that it will be billed for its share of ESC's rent during the rate year pursuant to the service company agreement (Exh. ES-DPH/ANB-4, Sch. 2; Tr. 8, at 1048; RR-DPU-8).

When lease expenses are based on a new or renovated facility, part of the Department's decision on whether the lease expenses are reasonable has been based on whether the underlying investment is in use. See Massachusetts Electric Company/Nantucket Electric Company, D.P.U. 09-39 (2009) (disallowing lease expenses associated with facility renovations that would not have been completed for six months); Bay State Gas Company, D.P.U. 13-75, at 210 (2014) (allowing lease expenses associated with new facilities based on the lease's occupancy date). The Attorney General contends that there is insufficient evidence to support a finding that the Auburn AWC is in use. We disagree. Based on the executed lease agreement commencing August 31, 2020; the Company's testimony at the evidentiary hearings concerning the work remaining before 100 NSTAR Gas employees would be relocated to the Auburn AWC; the occupancy permit documentation provided on the record; and the evidence that the facility will be occupied by NSTAR Gas employees by the rate year, we find that substantial evidence demonstrates the Auburn AWC is in use and providing benefits to ratepayers (Exh. AG 24-19; Tr. 2, at 349-350; Tr. 8, at 1039-1050; Tr. 12, at 1551-1552; RR-DPU-8 (Supp.), Att.).

Turning to whether the amount of lease expense is reasonable and known and measurable, the Department has reviewed the testimony and documentation regarding the Auburn AWC, including but not limited to project authorization documentation, alternatives analyses, fixed price contracts, and a detailed breakdown of the costs removed from the calculation of lease expense due to the removal of the training facility from the project's scope (Exhs. ES-LML/TCD-11, at 1-56; ES-RR/CPP-Rebuttal-1, at 30; DPU-ES 6-7; DPU-ES 6-10; DPU-ES 6-15; DPU-ES 33-5; AG 24-17; AG 24-20; AG 24-22; AG 25-6; AG 38-1 & Atts.; AG 42-4; AG 42-5; AG 42-6). The Department finds that the Company adequately explained Eversource's available alternatives and justified the decision to proceed with developing the Auburn AWC in consideration of business needs, cost, and efficiency (Exhs. ES-LML-TCD-1, at 53; DPU-ES 6-10 & Att.; DPU-ES 6-15; AG 24-17). Further, the Department has reviewed the investments costs included in the calculation of lease expense and finds that NSTAR Gas has correctly accounted for the removal of the training facility (Exh. AG 38-1, Att. (d)). Additionally, though the leases provide that the Company's allocated portion of costs during the rate year shall include operation, maintenance, and capital costs, NSTAR Gas has calculated its proposed lease expense based only on Eversource's known and measurable capital costs, so the amount of lease expense proposed by NSTAR Gas is likely less than the expenses it will incur in the rate year (Exhs. ES-DPH/ANB-2, Sch. 17; ES-DPH/ANB-4, Schs. 2, 7; AG 38-1, Att. (d); Tr. 8, at 1048; RR-DPU-8 (Supp.) & Att.). Therefore, we find that the investment costs included in the calculation of NSTAR Gas's lease expense are reasonable and known and measurable. Also, we find the allocation of lease expense to NSTAR Gas based on square-footage occupancy is reasonable (Exh. DPU-ES 33-6).

Like the Enterprise IT project investments discussed in Section VIII.B, above, in this proceeding the Department explored whether the Company had realized any known and measurable cost savings as a result of the Auburn AWC (Exhs. ES-LML/TCD-1, at 53; DPU-ES 6-10 & Att. at 3-4; DPU-ES 33-4; DPU-ES 33-9; AG 24-22; Tr. 8, at 1046-1047). The record shows that the Company's decision to relocate the area work center from the facility in Worcester, Massachusetts was in part predicated on avoided costs, such as significant investments at the Worcester location; investment in a new facility in Woburn, Massachusetts; and investments in Waltham, Massachusetts and Southborough, Massachusetts to address congestion at those facilities (Exhs. ES-LML/TCD-1, at 53; DPU-ES 6-10 & Att. at 3-4; DPU-ES 33-4). These avoided costs keep the Company's cost of service lower than it would have been if one of the alternatives was chosen (Exh. DPU-ES 6-10). Further, the evidence shows that the Company plans to repurpose the facility in Worcester, Massachusetts, which remains used and useful to customers, so it would be inappropriate to remove costs associated with that facility from the cost of service (Exhs. DPU-ES 33-9; AG 24-22; Tr. 8, at 1046-1047). Based on the record, the Department is unable to find that there are known and measurable cost of service savings associated with the Auburn AWC; and, therefore, we reject the Attorney General's request to disallow the Auburn AWC lease expenses on that basis. D.P.U. 15-155, at 307; D.P.U. 13-75, at 114; D.T.E. 05-27, at 129-131; D.T.E. 03-40, at 11.

d. Conclusion

NSTAR Gas's proposed a final lease expense of $4,938,105 (Exh. ES-DPH/ANB-2 (Rev. 3), Sch. 17). As discussed above, NSTAR Gas calculated the remaining lease expenses using the proposed pre-tax WACC of 9.76 percent. Applying the 9.33 percent pre-tax WACC approved by the Department in Section XI, below, to the applicable leases yields a lease expense of $4,796,830 (Exh. DPU-ES 1-10 (Rev.), Atts. (a), (b), (c)). In addition, the Department has disallowed $34,617 for lease expense associated with 56 Prospect Street. Accordingly, the Department will decrease the Company's cost of service in Schedule 2 by $175,892.[120]

In accordance with the findings described in this section, the Department concludes that the allowed lease expense of $4,762,213[121] is reasonable and based on known and measurable adjustments to the Company's test-year level of expense. Further, the Department determines that the Company's lease expenses associated with affiliates are for

120 $4,938,105 – $4,796,830 + $34,617 = $175,892

121 $4,938,105 - $175,892 = $4,762,213

activities that specifically benefit the regulated utility and that do not duplicate services already provided by the utility; are made at a competitive and reasonable price; and are allocated to NSTAR Gas by a formula that is both cost effective in application and nondiscriminatory (Exhs. DPU-ES 1-9; DPU-ES 1-10 (Rev.); AG 1-26, Att. (a); AG 1-64 (Supp.); AG 24-23).[122]

D. Service Company Expense

1. Introduction

ESC bills NSTAR Gas and other Eversource subsidiaries for administrative, corporate, and management services (Exhs. ES-DPH/ANB-1, at 23-24; DPU-ES 1-1). ESC performs functions such as accounting, auditing, communications, rates, legal, regulatory affairs, information technology, and human resources for NSTAR Gas and other Eversource subsidiaries (Exh. DPU-ES 1-2). Service company charges are comprised of (1) direct charges billed for costs incurred and work performed by service company personnel directly related to the respective subsidiary and (2) the allocated portion of common costs that are shared among the respective subsidiaries receiving the service based on appropriate allocation factors (Exh. ES-DPH/ANB-1, at 24). ESC bills the Company based on its service agreement with NSTAR Gas (Exhs. ES-DPH/ANB-1, at 24; ES-DPH/ANB-4, Sch. 2; AG 1-26, Att. (a)).

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122 Minor discrepancies in any of the amounts appearing in this section are due to rounding.

NSTAR Gas included ESC charges in the corresponding expense categories in the test year (e.g., Enterprise IT Project Costs, Payroll Expense) (see Exhs. ES-DPH/ANB-2, Schs. 11, 15; AG 1-28, Att. (a)). Additionally, the Company included various ESC charges in normalizing known and measurable adjustments to the cost of service in the appropriate expense categories. For example, the intercompany rents associated with ESC facilities that are allocated to NSTAR Gas are included in the Company's proposed adjustment to lease expense (Exhs. ES-DPH/ANB-2, Sch. 17; AG 1-28, Att. (a)). During the test year, NSTAR Gas booked $50,465,146 in charges from ESC (Exh. AG 1-28, Att. (a) at 2).

2. Positions of the Parties

a. Attorney General

The Attorney General argues that the Company failed to recognize the economies of scale savings associated with Eversource's acquisition of Bay State (Attorney General Brief at 62). The Attorney General notes that while Eversource has not yet assumed Bay State's operations, the economies of scale are significant and insists that the Department should recognize these economies by reducing the pro forma cost of service accordingly (Attorney General Brief at 62). The Attorney General contends that the allocation of ESC's common costs will be known before the beginning of the rate year in this case (Attorney General Brief at 63). The Attorney General adds that the size of Bay State's operations is similar to NSTAR Gas's operations and the share of ESC's common costs that should be allocated to Bay State should be equal to or greater than that of NSTAR Gas (Attorney General Brief at 64). The Attorney General recommends that the Department reduce the Company's service company expense by $489,469 to reflect changes in-service company allocations as a result of Eversource's acquisition of Bay State (Attorney General Brief at 65).

b. Company

The Company argues that each of the services provided by ESC to NSTAR Gas are beneficial to customers because the services are necessary to provide utility service and the Company could not operate without these functions (Company Brief at 159, citing Exh. DPU-ES 1-2 (Rev. 1)). NSTAR Gas contends that the service company charges are reasonable and allocated consistent with the Department's standards, and the Company maintains that costs directly charged or allocated to the Company by ESC are for activities that specifically benefit the Company in providing service to its customers and that do not duplicate services already provided by Company personnel (Company Brief at 161, citing Exh. DPU-ES 1-9). NSTAR Gas asserts that the services provided to the Company by ESC are provided most cost effectively on a shared basis across the Eversource operating companies (Company Brief at 161, citing Exhs. ES-DPH/ANB-4, Sch. 2; AG 1-26, Att. (b) at 14-16). The Company recommends that the Department approve the corporate service company charges included in the Company's revenue requirement calculations for NSTAR Gas (Company Brief at 164).

The Company argues that the Department should reject the Attorney General's recommendation to reduce the Company's service company expenses, claiming that the Attorney General is recycling a failed argument from D.P.U. 17-05, where the Attorney General argued that the Eversource acquisition of Aquarion Water Company of

Massachusetts, Inc. would reduce the costs allocated to NSTAR Electric and WMECo, post-acquisition (Company Brief at 164-165, citing D.P.U. 17-05, at 159-160). The Company maintains that the Department determined that any future allocation of costs was speculative and did not satisfy its standard that proposed changes to test-year revenues, expenses, and rate base require a finding that the adjustment constitutes a known and measurable change to the test-year cost of service (Company Brief at 165, citing D.P.U. 17-05, at 170). The Company argues that the findings in D.P.U. 17-05 are analogous to the situation in this case (Company Brief at 165). The Company adds that ESC agreed to a pricing method for services provided by NiSource Inc. to Eversource that create costs that would offset savings, making the Attorney General's recommendation inappropriate (Company Brief at 166, citing D.P.U. 20-59, Exhs. JP-DPH-1, at 40-41; JP-SA-2). The Company asserts that the Department should reject the Attorney General's recommendation (Company Brief at 166).

### 3. Analysis and Findings

#### a. Introduction

The Department permits rate recovery of payments to affiliates where these payments are: (1) for services that specifically benefit the regulated utility and that do not duplicate services already provided by the utility; (2) made at a competitive and reasonable price; and (3) allocated to the utility by a 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. 17-05, at 163; D.P.U. 15-155, at 270-271; D.P.U. 13-75, at 184; D.P.U. 12-25, at 231; D.P.U. 89-114/90-331/91-80 (Phase I) 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 (1985). In addition, 220 CMR 12.04(3) provides that, "[a]n Affiliated Company may sell, lease, or otherwise transfer an asset to a Distribution Company, and may also provide services to a Distribution Company, provided that the price charged to the Distribution Company is no greater than the market value of the asset or service provided."

b. Services

In determining whether the services rendered by an affiliate specifically benefit a regulated utility and do not duplicate services already provided by the utility, it is necessary to examine whether there is any overlap between the services rendered by an affiliate and the operating company's functions. D.P.U. 17-05, at 163; D.P.U. 15-155, at 271; D.P.U. 13-75, at 184; D.P.U. 08-27, at 80-81; Oxford Water Company, D.P.U. 1699, at 11-12 (1984). ESC provides services that include the following: accounting; payroll; auditing; finance/business planning; business continuity and emergency response; communications; human resources; engineering; construction; corporate matters and corporate records; risk management; gas plant operations and management; environmental; insurance; tax; legal; treasury; regulatory; energy efficiency services; facilities; information technology; and customer relations for NSTAR Gas and other Eversource subsidiaries (Exhs. ES-DPH/ANB-4, Sch. 2, at 2-5; DPU-ES 1-2 (Rev. 1); DPU-ES 1-9). The Company does not have employees who perform these tasks (Exh. DPU-ES 1-9). Therefore, these activities specifically benefit NSTAR Gas, and there is no overlap between the services rendered by ESC and the Company's functions.

c. Price

Next, we evaluate whether ESC charges to NSTAR Gas were at a competitive and reasonable price. In prior cases, when determining whether services were charged at a competitive and reasonable price, the Department has accepted a review of employer compensation structures, compared to the market, because service company charges tend to be primarily labor related. D.P.U. 17-05, at 164; D.P.U. 15-155, at 272; D.P.U. 13-75, at 186; D.P.U. 12-25, at 233; D.P.U. 09-39, at 260. Regarding a review of ESC's compensation structures, the Company's proposal shows that it pays competitive, market-based wages based on comprehensive study and analysis of market conditions (Exhs. ES-SL-1, at 4-6, 11-12, 14-15, 17-20; ES-SL-6; ES-SL-7). Moreover, ESC labor is charged to the Company at cost and does not include a profit that would be charged by an outside vendor (Exhs. DPU-ES 1-2 (Rev. 1); DPU-ES 1-9). Based on the foregoing, the Department finds that the ESC expenses charged to NSTAR Gas were charged at a competitive and reasonable price.

d. Allocation

Finally, we evaluate the method of allocating costs from ESC to NSTAR Gas. When allocating costs among affiliates, it is preferable that costs associated with a specific utility are directly assigned to that utility. In the absence of a clear relationship between the cost and the affiliate, or when costs cannot be directly assigned, these costs are preferably allocated using cost-causative allocation factors, to the extent such allocation factors can be applied, with general allocation factors used to allocate any remaining costs. D.P.U. 17-05, at 168-169; D.P.U. 15-155, at 274; D.P.U. 13-75, at 188; D.P.U. 11-01/D.P.U. 11-02, at 318-321; D.P.U. 10-114, at 271-274.

As previously stated, ESC charges are charged directly to the Company or, when direct assignment is not possible, through allocation factors (Exhs. DPU-ES 1-2 (Rev. 1); DPU-ES 1-4; DPU-ES 1-9; AG 1-28). NSTAR Gas provided detailed information on all allocation codes and the metrics used to calculate them during the test year (Exhs. ES-DPH/ANB-1, at 23-24; DPU-ES 1-2 (Rev. 1); DPU-ES 1-4; DPU-ES 1-9; AG 1-28). Additionally, the Company's allocation rates within each allocation method are updated annually for the most recent source data available; and if there are significant changes during the year, allocation rates are updated to reflect those changes (Exh. AG 24-23). No significant changes have been made to ESC's allocation rates since the Department last reviewed them in D.P.U. 17-05, for NSTAR Electric (Exhs. DPU-ES 1-9, AG 24-23). In D.P.U. 17-05, at 169-170, the Department reviewed the method of allocation for ESC's charges and found that it was cost effective and nondiscriminatory. The Department has again reviewed these allocation codes and metrics, and we find them to be cost effective and nondiscriminatory.

The Attorney General recommends that the Department reduce the overall level of costs allocated to the Company to account for potential savings associated with Eversource's acquisition of Bay State (Attorney General Brief at 62; Attorney General Reply Brief at 16-17). Proposed changes to test-year revenues, expenses, and rate base require a finding that the adjustment constitutes a known and measurable change to test-year cost of service. D.P.U. 17-05, at 170; D.P.U. 1580, at 13-17, 19; D.P.U. 84-32, at 17; Massachusetts Electric Company, D.P.U. 136, at 3 (1980); Chatham Water Company, D.P.U. 19992, at 2 (1980); D.P.U. 18204, at 4; New England Telephone & Telegraph Company, D.P.U. 18210, at 2-3 (1975); Boston Gas Company, D.P.U. 18264, at 2-4 (1975). It is also well-recognized that cost savings arising from merger activities may be considered by the Department, to the extent that such savings can be quantified under a known and measurable standard. Plymouth Water Company, D.P.U. 14-120, at 108-112 (2015); D.P.U. 09-39, at 275; Bay State Gas Company/Unitil Corporation, D.P.U. 08-43-A, at 45 (2008).

Eversource only acquired Bay State's assets in the last month. Any future revisions to the allocation of service company expenses between NSTAR Gas and Eversource Gas of Massachusetts are speculative and do not constitute a known and measurable change to NSTAR Gas's cost of service. Accordingly, the Department declines to accept the Attorney General's recommended adjustments to account for any savings associated with Eversource's acquisition of Bay State.

4. Conclusion

Based on the foregoing, we find that NSTAR Gas has sufficiently demonstrated that the service company allocations are (1) for activities that specifically benefit the Company and that do not duplicate services already provided by NSTAR Gas; (2) made at a competitive and reasonable price; and (3) allocated to the Company by a method that is both cost-effective and nondiscriminatory. Other sections of this Order address issues related to ESC costs specific to those categories of costs.

E. Insurance Expense and Injuries and Damages Expense

1. Introduction

In its initial filing, the Company proposed a pro forma test-year expense of $1,105,204 for insurance expense and injuries and damages expense (Exhs. ES-DPH/ANB-1, at 64-69; ES-DPH/ANB-2, Sch. 16, at 1-3). The Company proposed an adjusted test-year expense of $972,391 and a pro forma adjustment of $132,813 based on the most recent insurance policies in effect at the time as well as an adjustment to injuries and damages expense to account for the last five years of data (Exhs. ES-DPH/ANB-1, at 64-69; ES-DPH/ANB-2, Sch. 16, at 1-3). NSTAR Gas's pro forma insurance expense included excess general liability insurance policies that ESC procured after the Merrimack Valley incident (Exhs. ES-DPH/ANB-1, at 68; AG 6-18; Tr. 2, at 236-237).[123] During these proceedings, the Company updated the pro forma adjustment to $138,296 to reflect the most recent insurance policies and the difference between the five-year average of self-insured claims paid and the actuarially determined expense booked during the test year, resulting in a proposed expense of $1,110,687 (Exhs. ES-DPH/ANB-1, at 65; ES-DPH/ANB-2 (Rev. 3), Sch. 16, at 1-3).

123 ESC procured the excess general liability coverage and assigned the costs equally to the gas distribution businesses operating under Eversource: Yankee Gas and NSTAR Gas (Exhs. ES-DPH/ANB-1, at 68; ES-DPH/ANB-3 (Rev. 3), WP 16).

2. Positions of the Parties

a. Attorney General

The Attorney General argues that the Department should remove $575,952 of proposed excess general liability insurance expense obtained by ESC on behalf of NSTAR Gas in response to the Merrimack Valley incident from the cost of service because customers should not be required to cover the costs of utility imprudence, either through direct payment to cover those liabilities or through an insurance premium for a third party to cover costs (Attorney General Brief at 57). The Attorney General maintains that the Company bears the burden of demonstrating that the costs benefit Massachusetts ratepayers, are reasonable, and were prudently incurred (Attorney General Brief at 57-58, citing D.P.U. 11-01/D.P.U. 11-02, at 323). The Attorney General claims that excess general liability insurance associated with events like the Merrimack Valley incident provides no benefits to customers and alleges that the policies only exist to protect shareholders from costs to cover potential future negligence on the part of the Company (Attorney General Brief at 58). The Attorney General raised no other objections to the Company's proposed insurance expense or injuries and damages expense.

b. Company

The Company maintains that the Department allows post-test year updates to O&M expense where those updates are demonstrated to be known and measurable changes up to the midpoint of the rate year (Company Brief at 214, citing D.P.U. 12-25, at 133-134; D.P.U. 14-150, at 45; D.P.U. 15-155, at 13; D.P.U. 17-05, at 22; D.P.U. 17-170, at 35-36). The Company argues that it has met its burden for the allowance of insurance expense because the costs associated with excess general liability insurance are known and measurable and the Company's customers benefit from the retention of both general liability insurance and excess general liability insurance (Company Brief at 215, citing Exhs. ES-DPH/ANB-1, at 67-69; AG 6-18; AG 6-20; AG 6-21).

The Company asserts that ESC worked with its insurance broker after the Merrimack Valley incident to revisit its general liability limits for insurance specifically associated with the Eversource gas distribution business (Company Brief at 211, citing Exh. ES-DPH/ANB-1, at 68). The Company claims that $100 million of Eversource's total $300 million in excess general liability coverage was purchased as a result of exposure from the Company's gas business and the potential losses associated with catastrophic events (Company Brief at 212, citing Exh. AG 6-18).

The Company contends that the Attorney General inaccurately equates the purpose of carrying excess general liability insurance to purchasing protection against negligence on the part of the insured (Company Brief at 213, 215). The Company alleges that, to the contrary, this insurance will close coverage gaps and add extra layers of protection for customers and the Company from costs arising from an unexpected event (Company Brief at 213). Moreover, the Company maintains that if investors do not have confidence regarding NSTAR Gas's risk management and they invest elsewhere, as may occur should the Company carry insufficient insurance coverage, then the Company would experience cash flow constraints and higher costs of capital that will negatively impact operations and drive up costs borne by customers (Company Brief at 214).

3. Analysis and Findings

Rates are designed to allow for recovery of a representative level of a company's revenues and expenses based on a historic test year adjusted for known and measurable changes. D.P.U. 10-55, at 274; D.P.U. 09-30, at 218; D.T.E. 02-24/25, at 161; D.P.U. 92-250, at 106. The Department will include the most current cost of liability and property insurance, based on a signed agreement, as a reasonable cost of service. D.P.U. 10-55, at 276; D.P.U. 09-30, at 218; D.T.E. 02-24/25, at 161; North Attleboro Gas Company, D.P.U. 86-86, at 8-10 (1986); D.P.U. 84-94, at 44. The Department requires companies to provide evidence that they undertook reasonable measures to control property and liability insurance expenses. D.P.U. 08-35, at 119-120; D.T.E. 05-27, at 133-134; D.T.E. 03-40, at 184-185. In addition, the Department has used a five-year average to determine the level of self-insured payments for ratemaking purposes. Fitchburg Gas and Electric Light Company, D.P.U. 13-90, at 106 (2014); D.P.U. 10-55, at 272; Massachusetts Electric Company, D.P.U. 89-194/195, at 73-75 (1990).

The Attorney General has argued that $575,952 related to excess general liability insurance should be removed from the cost of service because the insurance policies obtained following the Merrimack Valley incident protect the Company's shareholders against potential negligence on the part of the Company, not Massachusetts ratepayers as required by Department precedent (Attorney General Brief at 57-58). The Company contends that the Attorney General's position is inaccurate with respect to the purpose of the polices and that the polices do benefit ratepayers (Company Brief at 213-215).

In determining whether ratepayers receive measurable benefits in exchange for the cost of purchasing insurance, the Department examines whether the ratepayers would otherwise be required to pay for the costs covered by the insurance. Western Massachusetts Electric Company, D.P.U. 87-260, at 73. For example, to the extent expenses related to bad faith actions on the part of a company are not allowable as a cost of service item, costs associated with an insurance policy with the primary purpose of providing coverage in situations involving bad faith must also be borne by the company's shareholders. D.P.U. 87-260, at 72. In this case, however, ESC determined that it was prudent after the Merrimack Valley incident to revisit the limits of its general liability coverage and procured excess general liability policies that will cover costs associated with catastrophic events whether or not there is any fault on behalf of the Company (Exhs. ES-DPH/ANB-1, at 68; AG 1-61 (Supp. 2); Tr. 2, at 233). We conclude that coverage by the excess general liability policies primarily involve actions where the costs could be included in the Company's cost of service absent the insurance. We cannot find, on this record, that the primary purpose of these policies is to cover bad faith or imprudent conduct by the Company or other costs that are not includable; therefore, we find that the excess general liability insurance serves to benefit customers.

The Department has reviewed NSTAR Gas's signed insurance policies, insurance premium invoices, and supporting documentation and finds that the Company's insurance expense premiums are based on actual policy rates and are thus known and measurable (Exhs. ES-DPH/ANB-1, at 65-66; AG 1-61 & Atts.; AG 1-61 (Supp. 2) & Atts.; AG 6-12;

AG 6-13; AG 6-17). Further, the Department finds that the Company has taken reasonable measures to control property and liability insurance expense (Exhs. ES-DPH/ANB-1, at 65-66; AG 1-61 & Atts.; AG 1-61 (Supp. 2) & Atts.; AG 6-12; AG 6-13; AG 6-17). Lastly, the Company submitted documentation supporting the calculation of the five-year average of self-insurance expense (Exhs. ES-DPH/ANB-1, at 69; ES-DPH/ANB-2 (Rev. 2), Sch. 16). The Department finds that the Company has correctly calculated the adjustment to the self-insured portion of its insurance expense. For all the reasons set forth above, the Department allows the Company's proposed insurance expense and injury and damages expense of $1,110,687.

### F. Regulatory Assessment

#### 1. Introduction

During the test year, NSTAR Gas recorded $809,303 in regulatory assessments charged by the Department and the Attorney General (Exh. DPU-ES 4-8 & Att.). This amount comprises a fiscal year 2018 amount of $818,908 and a true-up associated with the fiscal year 2017 amount of negative $9,604, as the Company's test year is a calendar year, and regulatory assessments are assessed on a fiscal year basis (Exh. DPU-ES 4-8 & Att.). Under traditional ratemaking, a representative level of regulatory assessments would be included in a gas company's cost of service in calculating its revenue requirement in establishing rates in a base distribution rate case. The representative level would include the test year amount of regulatory assessments adjusted for known and measurable changes. Currently, the ratemaking treatment for regulatory assessments for jurisdictional electric and gas companies is consistent with these principles.

The Company proposes to remove regulatory assessment costs from the base revenue requirement and instead to recover such costs through a new reconciling mechanism component to the Attorney General Consultant Expense ("AGCE") Factor, which is part of the LDAF (Exh. ES-DPH/ANB-1, at 22, 36-37, 134).[124] The Company points to annual increases and fluctuations beyond its control as drivers of the proposal (Exh. ES-DPH/ANB-1, at 134-135). To effectuate this change, NSTAR Gas removed $809,303 in test-year regulatory assessments from the calculated revenue requirement (Exhs. ES-DPH/ANB-1, at 22-23, 36; ES-DPH/ANB-2 (Rev. 3), Sch. 9).

2. Positions of the Parties

a. Company

NSTAR Gas contends that the Department's regulatory assessments are appropriate for recovery through a reconciling mechanism such as the AGCE Factor (Company Brief at 111-112, 114). The Company alleges that (1) the recently increased cap on the Department's general assessment from 0.2 percent to 0.3 percent of intrastate operating revenues and (2) supplemental assessments in 2019 for the independent examination of natural gas infrastructure safety in Massachusetts, represent significant increases over past

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124 Pursuant to G.L. c. 12, § 11E(b), the Attorney General can recover from gas companies the costs incurred for expert and consultants retained in Department proceedings as approved by the Department. These costs are recognized as "proper business expenses of the affected party, recoverable through rates without further approval from the [D]epartment." G.L. c. 12, § 11E(b). NSTAR Gas recovers its Attorney General charges as part of its annually reconciling LDAF, which is included in its Local Distribution Adjustment Clause. M.D.P.U. No. 402S, § 9.6. All jurisdictional electric and gas companies recover their Attorney General expert and consultant costs through an annually reconciling mechanism.

assessments, and that these regulatory assessments will continue to increase in the future (Company Brief at 112-113, citing Exhs. ES-DPH/ANB-1, at 134-135; AG 6-31).[125] Additionally, NSTAR Gas maintains that the increases in regulatory assessments levied fluctuate from year-to-year beyond the Company's control (Company Brief at 113). The Company argues that the Department has found reconciling mechanisms appropriate in instances where the costs being recovered are beyond the control of the company, fluctuate annually, and are large in magnitude; and that regulatory assessments are consistent with these criteria (Company Brief at 114, citing Exh. DPU-ES 4-11; Investigation into Rate Structures that Promote Deployment of Demand Resources, D.P.U. 07-50-A at 50 (2008)).

NSTAR Gas notes that reconciling mechanisms are a useful ratemaking tool to avoid repetitive and costly rate proceedings resulting from fluctuations in costs (Company Brief at 114). The Company indicates that regulatory assessment costs have increased by over $400,000 from the approximate $700,000 included in base distribution rates in D.P.U. 14-150 and warns the Department that any permanent deficiency could move the Company toward a rate proceeding (Company Brief at 114, citing Exh. DPU-ES 12-42). Moreover, the Company avers that if a future assessment were to drop in amount, customers would realize the benefit of cost savings through the reconciling mechanism on a slight lag (Company Brief at 114-115). If the Department does not accept the Company's proposal,

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125 Acts of 2019, c. 41, § 21 amended G.L. c. 25, § 18 effective July 1, 2019 (increase in the cap on the Department's general assessment from 0.2 percent of electric and gas companies' intrastate revenues to 0.3 percent).

NSTAR Gas states that the revenue requirement must be increased to reflect the recovery of regulatory assessments in base distribution rates (Company Brief at 112, n. 38).[126] No other party commented on this issue on brief.

3. Analysis and Findings

Pursuant to G.L. c. 25, § 18, the Department is authorized to impose an assessment against each electric and gas company under its jurisdiction. Fiscal Year 2020 General Assessment, D.P.U. 20-ASMT-01, at 1 (March 12, 2020).[127] The most recent Department general assessment for fiscal year 2020 was $1,138,178 for NSTAR Gas (Exhs. DPU-ES 12-40 (Supp.), Atts. (a) & (b) at 7). D.P.U. 20-ASMT-01, at 4. This general assessment is intended to reimburse the Commonwealth of Massachusetts for the funds appropriated by the General Court for the operation and administration of the Department and is credited to the General Fund. G.L. c. 25, § 18. The general assessment levied by the Department is allocated proportionately to each electric and gas company based on each company's total intrastate operating revenues. D.P.U. 20-ASMT-01, at 3; G.L. c. 25, § 18. The general assessment was previously limited to 0.2 percent of each company's intrastate operating

126 NSTAR Gas states that the most recent regulatory assessments levied by the Department and the Attorney General total $1,352,042 (Company Brief at 113, citing, Exh. DPU-ES 12-40 (Supp.), Atts. (a) & (b)) (Department fiscal year 2020 general assessment of $1,138,178 + Department supplemental assessment of $77, 762 + Attorney General fiscal year 2019 assessment of $136,172).

127 The Commonwealth's fiscal year extends from July 1 through June 30. Fiscal year 2020 ran from July 1, 2019 through June 30, 2020.

revenues but was recently increased to 0.3 percent of each affected company's intrastate operating revenues. St. 2019, c. 41, § 21.

The Department also levied supplemental assessments to jurisdictional gas companies in two installments to pay for an independent statewide examination of the gas distribution infrastructure in the Commonwealth pursuant to the Chairman's Fifth Set of Orders under G.L. c. 25, § 4B, issued on January 14, 2019[128] and the Chairman's Fourteenth Set of Orders under G.L. c. 25, § 4B, issued on May 11, 2020 (Exh. DPU-ES 12-40 (Supp.), Atts. (a) & (b)).[129] The supplemental assessments to NSTAR Gas were $264,106 and $77,692. Supplemental Assessment to Gas Companies, D.P.U. 19-ASMT-01-A at 2 (April 26, 2019); Supplemental Assessment to Gas Companies, D.P.U. 20-ASMT-01-A at 2 (May 12, 2020). As with the general assessment, these supplemental assessments were allocated proportionally based on intrastate revenues. D.P.U. 19-ASMT-01-A at 2; D.P.U. 20-ASMT-01-A at 1.

In addition, pursuant to G.L. c. 24A, § 3, the Office of Consumer Affairs and Business Regulations makes an annual assessment on behalf of the Attorney General against each electric, gas, water, telephone, and telegraph company subject to the Department's jurisdiction. This assessment credits the general fund for a level of personnel costs of the Attorney General for exercising her authority under G.L. c. 12, § 11E (participating in

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128 See also, St. 2019, c, 5, § 2A, line item 2100-0020.

129 The Fourteenth Set of Orders requires investor-owned gas distribution companies regulated by the Department to pay for an independent statewide examination of the safety of the Commonwealth's gas distribution system that was conducted by the Dynamic Risk Assessment Systems, Inc. Supplemental Assessment to Gas Companies, D.P.U. 20-ASMT-01-A at 1 (May 12, 2020).

proceedings before the Department). As with the general assessment and the supplemental assessments levied by the Department, this assessment is allocated proportionately to each affected company based on each company's intrastate operating revenues. G.L. c. 24A, § 3.

All of these assessments would be considered normal operating costs for the affected company: G.L. c. 25, § 18 ("Assessments made under this section may be credited to the normal operating cost of each company."), G.L. c. 25, § 4B ("Expenses authorized by the [C]hairman under this section may be recognized by the [D]epartment for all purposes as proper business expenses of the affected utility or alternative utility subject to investigation and recovery through rates."), and G.L. c. 24A, § 3 ("Assessments made under this section may be credited to the normal operating costs of each such company…"). In addition, adjustments to regulatory assessments may be includable in cost of service upon a showing that the proposed adjustment represents a known and measurable change to test-year cost of service. South Egremont Water Company, D.P.U. 95-119/95-122, at 18 (1996); Westport Harbor Aqueduct Company, D.P.U. 93-142, at 6 (1993); Boston Edison Company, D.P.U. 160, at 48-49 (1980).

When the Department considers whether to allow a new reconciling mechanism, the Department considers specific criteria, such as whether the costs at issue are: (1) volatile in nature; (2) large in magnitude; (3) neutral to fluctuations in sales; and (4) beyond the company's control. D.P.U. 10-55, at 66, n.43; Bay State Gas Company, D.T.E. 05-27, at 183-186 (2005); Boston Edison Company, Cambridge Electric Company, and Commonwealth Electric Company, D.T.E. 03-47-A at 25-28, 36-37 (2003); Eastern

Enterprises and Essex County Gas Company, D.T.E. 98-27, at 6, 28 (1998). In summary, as discussed below, considering all of these criteria, the Department finds that the Company has not demonstrated that the use of a reconciling mechanism is appropriate for the ratemaking treatment of regulatory assessment costs.

In this context, volatility involves the degree or fluctuation in regulatory assessments over time, including both the size and frequency of changes. In reviewing the Company's presentation of regulatory assessments from fiscal year 2010 through fiscal year 2020, we note that the Green Communities Act assessments (fiscal years 2011 and 2012) and the Department supplemental assessment under G.L. c. 25, § 4B (fiscal years 2019 and 2020) were non-recurring assessments and, thus, should not be included in examining volatility (Exh. DPU-ES 12-40 (Supp.), Att. (a)). Our review of the Company's regulatory assessments over this period, excluding these non-recurring regulatory assessments, shows changes in amounts from period to period but not of sufficient size or frequency to find that regulatory assessments are volatile in nature.

For these purposes, magnitude involves a measure or ordering or comparison to similar objects or categories. The amounts of the Company's regulatory assessments are not sufficiently large compared to cost categories that warrant recovery through a reconciling charge. For example, the Companies regulatory assessments for fiscal years 2019 and 2020, excluding the supplement assessments, were \$857,576 and \$1,138,178, respectively (Exh. DPU-ES 12-40 (Supp), Att. (a)). The Company's proposed revenue requirement for recovery of its annual pension and post-retirement benefits other than pensions for its 2020 pension adjustment factors ("PAFs") is $5,220,664. NSTAR Electric Company/NSTAR Gas Company, D.P.U. 19-123, at 4 (December 30, 2019) (provisional approval of 2020 PAFs subject to further review and reconciliation).

Turning to the third criterion, the regulatory assessments costs are not neutral to fluctuations in sales, as the amounts levied are calculated based on the Company's intrastate operating revenues (Exhs. ES-DPH/ANB-1, at 134; DPU-ES 12-40 (Supp.), Att. (b) at 1, 6, 11). G.L. c. 25, § 18; D.P.U. 20-ASMT-01, at 3; G.L. c. 24A, § 3.

Finally, with respect to the fourth criteria, the Department agrees that regulatory assessment costs are beyond the control of the Company. The level of these regulatory assessments is based on actions and activities of the Legislature, the Department, and the Attorney General.[130] However, as stated above, considering all of the relevant criteria, the Department finds that the ratemaking treatment for regulatory assessments through use of a reconciling charge is not warranted. Further, no jurisdictional electric or gas utility company recovers regulatory assessment costs through a reconciling mechanism, and the Department does not treat the implementation of new reconciling mechanisms lightly. Therefore, the Company's proposal is denied.

The Company's arguments beyond our analysis of the relevant criteria are unpersuasive. While the Company points to the potential administrative efficiency that can be gained with the implementation of a new reconciling mechanism by avoiding repetitive

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130 Actions by the affected companies and their industries could have some effect on the level of regulatory assessments.

and costly rate proceedings, there is no evidence that recovery of regulatory assessments through a reconciling mechanism would avoid or eliminate any future base distribution rate proceedings (Exh. DPU-ES 12-42).[131] NSTAR Gas also notes that any decreases in regulatory assessments would be returned to customers, but such a scenario lies in contrast to the Company's contention that regulatory assessments will increase in the future (Exhs. ES-DPH/ANB-1, at 134-135; AG 6-31).

Therefore, the Department applies traditional ratemaking principles to the Company's regulatory assessments and includes a representative level in cost of service, i.e., test-year regulatory assessments adjusted for known and measurable changes. The Company has requested that the Department include $1,352,042 as a representative amount for regulatory assessments as part of its revenue requirement if the inclusion of regulatory assessment costs is not allowed in the AGCE Factor (Company Brief at 112, n.38). This amount includes the fiscal year 2020 general assessment from the Department of $1,138,178, the fiscal year 2019 Attorney General assessment of $136,172, and the special assessment levied by the Department in 2020 of $77,692 (Exhs. DPU-ES 12-40 (Supp.), Atts. (a) & (b)). The Department finds that the special assessment levied by the Department in 2020 is a non-recurring expense and is, therefore, ineligible for recovery as a part of the representative amount to be included in the Company's revenue requirement. D.P.U. 10-55, at 302-303;

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131 The Department cannot find that the $400,000 increase in the Company's regulatory assessments since its last base distribution rate case stated in this exhibit would cause the Company's filing of a base distribution rate case.

Fitchburg Gas and Electric Light Company, D.T.E. 98-51, at 37 (1998); Oxford Water Company, D.P.U. 88-171, at 29 (1989); see, also, D.P.U. 1270/1414, at 32-33. We find that the Department's fiscal year general assessment and the Attorney General's fiscal year 2019 assessment, rather than the test year regulatory assessments, are known and measurable and representative of the Company's regulatory assessments. As such, the Department will increase the Company's revenue requirement by $1,274,350 (Exhs. DPU-ES 12-40 (Supp.), Atts. (a) & (b)).

## G. Rate Case Expense

### 1. Introduction

The Company initially estimated that it would incur $3,097,105 in rate case expense (Exhs. ES-DPH/ANB-1, at 84; ES-DPH/ANB-3, Sch. 19, at 1). Based on its final invoices and projected costs to complete the compliance filing, the Company proposes a total rate case expense of $3,400,501 (Exh. ES-DPH/ANB-3 (Rev. 3), Sch. 19, at 1). NSTAR Gas's proposed rate case expense includes costs related to legal representation; contractor costs; miscellaneous expenses associated with preparing the rate case (e.g., production costs); and expert consulting services related to the Company's (1) PBR proposal, (2) allocated cost of service study ("ACOSS"), (3) marginal cost of service study ("MCOSS"), (4) depreciation study, (5) cost of capital, and (6) cash working capital study (Exh. ES-DPH/ANB-1, at 76-77).

The Company proposes to recover rate case expense over a five-year period, consistent with the stay-out provision in its proposed PBR mechanism(Exhs. ES-DPH/ANB-1, at 85; ES-DPH/ANB-3 (Rev. 3), Sch. 19, at 1).

Allowing recovery of the Company's proposed rate case expense of $3,400,501 over five years would produce an annual expense of $680,100 (Exh. ES-DPH/ANB-3 (Rev. 3), Sch. 19, at 1).

2. Position of the Company[132]

The Company states that it strived to contain costs by inviting vendors to participate in a competitive bidding process and then designating an internal review committee to evaluate the bids submitted for each RFP based on vendor qualifications, relevant experience, capabilities, personnel, and price (Company Brief at 200-201, citing Exh. ES-DPH/ANB-1, at 77). The Company also asserts that it updated its rate case expense throughout the proceeding, as is consistent with Department precedent (Company Brief at 207, citing Exh. ES-DPH/ANB-1, at 84-85). Moreover, the Company contends that it adhered to the Department's standards regarding rate case expense and, therefore, the Department should approve the Company's proposal (Company Brief at 207).

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 actually been incurred and, thus, is considered known and measurable. New England Gas Company, D.P.U. 10-114, at 219-220 (2011); Fitchburg Gas and Electric Light Company, D.P.U. 07-71, at 99 (2008); Bay State Gas Company, D.T.E. 05-27, at 157 (2005);

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132 No other party addressed the Company's proposed rate case expense.

Fitchburg Gas and Electric Light Company, D.T.E. 98-51, at 61-62 (1998). Second, such expenses must be reasonable, appropriate, and prudently incurred. D.P.U. 10-114, at 220; Bay State Gas Company, D.P.U. 09-30, at 226-227 (2009); Massachusetts-American Water Company, D.P.U. 95-118, at 115-119 (1996).

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 220; D.P.U. 07-71, at 99; Boston Gas Company, D.T.E. 03-40, at 147 (2003); Fitchburg Gas and Electric Light Company, D.T.E. 02-24/25, at 192 (2002); Boston Gas Company, D.P.U. 93-60, at 145 (1993). Rate case expense, like any other expenditure, is an area in which companies must seek to contain costs. D.P.U. 10-114, at 220; D.P.U. 07-71, at 99; D.T.E. 03-40, at 147-148; D.T.E. 02-24/25, at 192; Boston Gas Company, D.P.U. 96-50 (Phase I) at 79 (1996). 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 220; Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 09-39, at 289-293 (2009); D.P.U. 09-30, at 238-239; D.T.E. 03-40, at 152-154. 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 220; Boston Gas Company/Colonial Gas Company/Essex Gas Company, D.P.U. 10-55, at 323 (2010); see also Barnstable Water Company, D.P.U. 93-223-B at 16-17 (1994).

b. Competitive Bidding Process

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 158-59; 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 a 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 service providers to submit complete bids and give the company sufficient time to evaluate the bids. D.P.U. 10-114, at 221; D.P.U. 10-55, at 342-343. Further, the RFP issued to solicit service providers must clearly identify the scope of work to be performed and the criteria for evaluation. 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 service provider 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 issued RFPs to retain outside consultants associated with its (1) legal services, (2) PBR proposal, (3) ACOSS analysis, (4) MCOSS analysis, (5) depreciation study, (6) cost of capital analysis, and (7) cash working capital study (Exh. ES-DPH/ANB-1, at 76-77). As noted above, the Company bears the burden of demonstrating that its selections of outside consultants and legal service provider are both reasonable and cost effective. D.P.U. 10-55, at 343; D.P.U. 09-30, at 230-231; D.T.E. 03-40, at 153.

The Company initially considered the capabilities of internal staff, including technical expertise, resources, and access to data, prior to soliciting outside consultants (Exh. DPU-ES 10-5). We find that the Company's decision to retain consultants, rather than using internal staff, to perform these tasks was reasonable given the complexity of the issues and the overall scope of this rate case.

The Company provided documentation demonstrating that it conducted a competitive bidding process for each of the above service providers (Exhs. DPU-ES 10-1, Atts.; DPU-ES 10-2, Atts.). Each RFP set forth the scope of work to be performed and listed the criteria required for qualification (Exh. DPU-ES 10-1, Atts.). The RFPs also outlined the evaluation criteria that the Company would apply to bidders, such as cost, strength of proposal, familiarity with the Company's operation, industry experience, approach, depth of understanding, and familiarity with Department precedent (Exh. DPU-ES 10-1, Atts.). Regarding price, the RFPs required bidders to include a not-to-exceed price cap for certain phases of the rate case and encouraged responsive bidders to propose alternative fee structures (Exh. DPU-ES 10-1, Atts.). The Company created an internal review committee for each RFP to evaluate responsive bids (Exh. DPU-ES 10-3).

NSTAR Gas mostly selected the service providers that offered the lowest prices for their respective services (Exh. DPU-ES 10-3). 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 (Exhs. DPU-ES 10-3; DPU-ES 19-2). 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 (Exhs. DPU-ES 10-3; DPU-ES 24-10). Neither the Attorney General nor any other party challenges the Company's retention of these consultants, or the costs associated with their services. Nevertheless, NSTAR Gas bears the burden to demonstrate that its choice of consultants was both reasonable and cost-effective. 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 RFPs and responses, we conclude that the Company's choice of attorneys and consultants was both reasonable and cost effective (Exhs. DPU-ES 10-1, Atts.; DPU-ES 10-2, Atts.). We 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-ES 10-2, Atts.; DPU-ES 10-3; DPU-ES 10-4; AG 6-25). Further, for each category, the Company appropriately selected a provider that possessed 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-ES 10-6 through DPU-ES 10-11). Based on the foregoing, the Department concludes that the Company conducted a fair, open, and transparent competitive bidding process for its attorneys and consultants (Exh. DPU-ES 10-1, Atts.).

The Company did not solicit bids for the contractor costs (Exh. DPU-ES 10-13). 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. The Berkshire Gas Company, D.T.E. 01-56, at 73 (2001). For the contractor costs, the Company states that, in 2017, ESC engaged in an RFP process to retain a managed services program vendor and that, as a result of that competitive solicitation, Randstad was awarded a five-year contract to provide contract labor services to ESC on an enterprise-wide basis (Exh. DPU-ES 10-13). The Company utilizes contract labor provided by Randstad where it is more cost-effective than adding full-time employees (Exh. DPU-ES 10-13). In this specific circumstance, the Department finds that conducting a separate RFP 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. Bay State Gas Company, D.P.U. 13-75, at 237 (2014); Bay State Gas Company, D.P.U. 12-25, at 192 (2012); D.P.U. 10-114, at 231; D.P.U. 09-30, at 232. Accordingly, we find that the Company has provided sufficient justification for foregoing the competitive bidding process in selecting Randstad to provide contract labor services. Moving 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. These expenses must be reasonable, appropriate, and prudently incurred. D.P.U. 10-114, at 220; D.P.U. 09-30, at 227; D.P.U. 95-118, at 115-119.

The Department has reviewed the invoices provided by the Company and finds that the invoices are properly itemized (Exhs. DPU-ES 10-15 & Atts.; DPU-ES 10-15 (Supp. 1) & Atts.; DPU-ES 10-15 (Supp. 2) & Atts.: DPU-ES 10-15 (Supp. 3) & Atts.; DPU-ES 10-15 (Supp. 4) & Atts.). In addition, the Department finds that the total costs associated with each service provider were reasonable, appropriate, proportionate to the overall scope of work provided, and prudently incurred (Exhs. DPU-ES 10-15 & Atts.; DPU-ES 10-15 (Supp. 1) & Atts.; DPU-ES 10-15 (Supp. 2) & Atts.: DPU-ES 10-15 (Supp. 3) & Atts.; DPU-ES 10-15 (Supp. 4) & Atts.). Accordingly, the Department approves the recovery as rate case expense of all costs associated with these consultants.

d. Normalization of Rate Case

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; Massachusetts Electric Company, D.P.U. 95-40, at 58 (1995). 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 74; D.T.E. 98-51, at 53; D.P.U. 96-50 (Phase I) at 77. 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 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.

Typically, 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).

The average interval between the Company's last four rate cases is nine years[133] (Exh. ES-DPH/ANB-1, at 85). The Company proposes to use the five-year stay out period

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133 In addition to the current filing, the Company's last general gas rate cases were D.P.U. 14-150, D.T.E. 05-85, and D.P.U. 91-60. Based on the Company's filing dates for these last four rate cases, between D.P.U. 19-120 and D.P.U. 14-150, the interval is five years; between D.P.U. 14-150 and D.T.E. 05-85, the interval is nine years; and between D.T.E. 05-85 and D.P.U. 91-60, the interval is fourteen years. The sum of these intervals, divided by three and rounded to the nearest whole number, results in a normalization period of nine years: 28/3 = 9.33, rounded to nine years.

in its proposed PBR to recover rate case expense over a five-year period (Exhs. ES-DPH/ANB-1, at 84; ES-DPH/ANB-3, Sch. 19, at 1). As discussed in Section V.B.4, above, however, the Department has approved a PBR Plan for the Company that includes a ten-year term and stay-out provision.

The Department has considered the term of a PBR proposal in establishing an appropriate rate case expense normalization period. D.P.U. 17-05, at 281-282; D.P.U. 09-30, at 241; D.P.U. 07-71, at 105; D.T.E. 05-27, at 163-164; D.T.E. 03-40, at 163; D.T.E. 01-56, at 75; D.P.U. 96-50 (Phase I) at 78. In addition, the Department has found that the term of a PBR that prevents a company from filing a new rate case for a predetermined period provides a more representative basis for establishing a rate case expense normalization period. D.P.U. 17-05, at 282; D.P.U. 96-50 (Phase I) at 78. Accordingly, the Department finds that a ten-year normalization period is appropriate.

e. Requirement to Control Rate Case Expense

The Department recognizes the extraordinary nature of a base distribution rate proceeding and the associated investment of resources that is required for a petitioner to adjudicate its case before the Department. These factors notwithstanding, we again emphasize the Department's concern with the amount of rate case expense associated with rate proceedings and the need for petitioners to control these costs. NSTAR Gas Company, D.P.U. 14-150, at 224 (2015); Fitchburg Gas and Electric Light Company, D.P.U. 11-01/D.P.U. 11-02, at 270 (2011); D.P.U. 10-55, at 341; D.P.U. 09-39, at 286; D.P.U. 09-30, at 227; New England Gas Company, D.P.U. 08-35, at 129 (2009);

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. Although we no longer require a company to file a specific proposal for shareholders to bear a portion of rate case expense, the Department's ability to disallow a company's recovery of rate case expense for failure to adhere to our strict requirements concerning competitive bidding, or for failure to pursue other reasonable cost-containment measures, or for failure to properly itemize rate case expense invoices, provides a sufficient incentive for companies to control rate case expense. Massachusetts Electric Company/Nantucket Electric Company, D.P.U. 15-155, at 245 (2016).

Before exercising authority to disallow recovery of rate case expense, the Department will closely scrutinize the RFP process to ensure that it is rigorous and demonstrates that the selected outside service providers chosen are reasonable and cost-effective. D.P.U. 15-155, at 245; D.P.U. 14-150, at 224; 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 expect cost-containment provisions to be included in rate case expense and companies to be aggressive in their cost-control measures. D.P.U. 15-155, at 245; D.P.U. 14-150, at 226-227; Fitchburg Gas and Electric Light Company, D.P.U. 13-90, at 177-178 (2014). We will exercise our authority to disallow recovery of rate case expense where a company fails to adhere to Department precedent and in instances where the amount of overall rate case expense appears to be excessive or disproportionate to the work performed. D.P.U. 15-155, at 246; D.P.U. 14-150, at 224; 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.

The Department has reviewed NSTAR Gas's RFP process and cost-containment measures and finds that the Company has complied with the Department's 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 each consultant's work, discounted consultant rates, and blended rates, in that these measures reduced the Company's overall rate case expense (Exh. DPU-ES 10-1, Atts.). We reach our conclusion based on the specific facts of this case and fully expect companies in future cases to demonstrate that they have taken aggressive measures to control their rate case expenses. Failure to do so will result in the disallowance of all or a portion of rate case expense.

4. Conclusion

NSTAR Gas has proposed and the Department has accepted a final rate case expense of $3,400,501 (Exh. ES-DPH/ANB-3, Sch. 19, at 1 (Rev. 3)). Based on a ten-year normalization period, the annual level of rate case expense to be included in the Company's cost of service is $340,050 ($3,400,501/ten years). Accordingly, the Department will reduce the Company's proposed cost of service by $340,050.

H. Depreciation

1. Introduction

During the test year, NSTAR Gas booked $35,223,816 in depreciation expense (Exhs. ES-DPH/ANB-1, at 89; ES-DPH/ANB-2 (Rev. 3), Sch. 22). The Company initially proposed a composite accrual depreciation rate of 2.49 percent and calculated a pro forma depreciation expense of $40,803,230, based on depreciable plant balances as of December 31, 2019 (Exhs. ES-DPH/ANB-1, at 88-90; ES-DPH/ANB-2 (Rev. 3), at Sch. 1, at 3; ES-JJS-2, at 7, 51). During the proceedings, NSTAR Gas proposed a revised depreciation expense of $37,328,792 to reflect updated 2019 plant balances, fully amortized intangible plant, and the stipulated adjustment discussed in Section IV above (Exhs. ES-DPH/ANB-2 (Rev.1), Sch. 1 at 3; ES-DPH/ANB-2 (Rev. 1), Sch. 22; ES-DPH/ANB-2 (Rev. 3), Sch. 22; ES-DPH/ANB-3 (Rev. 3), WP 22).

The Company's depreciation study is based on plant data as of December 31, 2018, and it analyzes accounting entries of plant transactions from the period 1981 through 2018 (Exhs. ES-DPH/ANB-1, at 89; ES-JSS-1, at 2, 5-6). NSTAR Gas estimated the service life and net salvage characteristics for depreciable plant accounts, and next used the service life and net salvage estimates to calculate composite remaining lives and annual depreciation accrual rates for each account (Exh. ES-JSS-1, at 6). To determine service lives, the Company used the retirement rate method to create life tables, which, when plotted, show an original survivor curve that is then compared to Iowa Curves[134] to determine an average service life for each plant account (Exhs. ES-JSS-1, at 7-8; ES-JSS-2, at 28). To determine net salvage values, the Company reviewed its actual salvage and cost of removal data for the period 1992 through 2018 (Exhs. ES-JSS-1, at 10, 13; ES-JSS-2, at 39).

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

With the exception of general plant assets, the Company relied on the straight-line remaining life method and average service life procedure to determine depreciation accrual rates (Exhs. ES-JSS-1, at 5, 10; ES-JSS-2, at 6, 8-9, 11). For general plant accounts 391.1, 391.2, 393, 394, 397, 397.1, and 398 the Company used straight-line amortization (Exhs. ES-JSS-1, at 5, 12; ES-JSS-2, at 11). Additionally, NSTAR Gas proposed a five-year amortization for its general plant reserve variance (Exhs. ES-JSS-1, at 4, 12; ES-JSS-2, at 51).

2. Positions of the Parties

NSTAR Gas states that during the proceeding the Attorney General submitted testimony recommending different survivor curves for Account 366 (Structures and Improvements), Account 367 (Mains), Account 369 (Measuring and Regulating Station Equipment), and Account 390 (Structures and Improvements) (Company Brief at 388). The Company notes that on June 3, 2020, NSTAR Gas and the Attorney General filed a stipulated agreement that addressed the survivor curves in dispute and updated the proposed composite depreciation accrual to 2.43 percent (Company Brief at 388). The Company argues that the Department should approve the proposed depreciation rates resulting from the stipulated agreement (Company Brief at 388). No other party commented on this issue on brief.

3. 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's 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; The Berkshire Gas Company, D.P.U. 905, at 13-15 (1982); Massachusetts Electric Company, D.P.U. 200, at 21 (1980).

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.[135] 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. 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

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135 Subjectivity is especially relevant in the calculation of net salvage factors where the cost to demolish or retire facilities cannot be established with certainty until the actual event occurs. D.P.U. 92-250, at 66; D.P.U. 1720, at 44; D.P.U. 1350, at 109-110.

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 other 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. D.P.U. 89-114/90-331/91-80 (Phase I) at 54-55. 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 intervenor review.

b. Resulting Accrual Rates

In Section IV, above, the Department approved the stipulated accrual rates for Accounts 366 (Structures and Improvements, 367 (Mains), and 369 (Measuring and Regulating Station Equipment). Based on our comprehensive review, the Department finds that NSTAR Gas has properly interpreted the results of its depreciation study and the underlying statistical analyses and used appropriate judgment in determining the depreciation accrual rates for the remaining plant accounts (Exhs. ES-DPH/ANB-3 (Rev. 3), WP 22; ES-JSS-1; ES-JSS-2; DPU-ES 4-17, Att.). Accordingly, the Department approves the Company's proposed composite accrual rate of 2.43 percent.

c. Amortization of General Plant and Unrecovered Reserves

NSTAR Gas has proposed amortization accounting for certain general plant accounts, namely, Account 391.1, Account 391.2, Account 393, Account 394, Account 397, Account 397.1, and Account 398 (Exh. ES-JSS-1, at 12). Amortization accounting is used for accounts with a large number of units, but small asset values (Exh. ES-JSS-1, at 12).

The Department previously approved amortization for the Company's general plant accounts in D.P.U. 14-150, at 197-198. Moreover, the Company's proposal is consistent with the requirements set forth by the Federal Energy Regulatory Commission's Accounting Release 15 for General Plant Accounts utilizing Vintage Year Accounting (Exh. DPU-ES 4-13). Accordingly, the Department approves NSTAR Gas's proposed amortization of general plant accounts.

As part of its depreciation study, the Company identified $576,343 in unrecovered reserves associated with the amortization of general plant accounts (Exhs. ES-JSS-1, at 12; DPU-ES 4-17, Att. at 51). The Company proposed to amortize the unrecovered reserves over a five-year period, resulting in an annual amount of $115,269 (Exh. DPU-ES 4-17, Att. at 51). NSTAR Gas explained that a five-year amortization period is the most commonly utilized period to properly align the reserve to plant ratio and argues that the five-year period is also consistent with the period of time before its next anticipated base distribution rate case (Exh. DPU-ES 4-14).

In the Company's last base distribution rate case, NSTAR Gas similarly proposed a five-year amortization for unrecovered reserves, which the Department found to be excessive upon considering the range of remaining lives of the Company's general plant assets, and we determined that an eight-year amortization period was more appropriate. D.P.U. 14-150, at 199. The remaining lives of general plant assets booked to Accounts 391.1, 391.2, 393, 394, 397, 397.1, and 398 range from 1.3 years for Account 391.2 to 19.4 years for Account 394 (Exh. DPU-ES 4-17, Att. at 50-51). In view of this range and consistent with our findings in D.P.U. 14-150, the Department finds a five-year amortization is inappropriate. Additionally, as discussed in Section V.B.4.e, above, the Department approved the PBRM with a ten-year term. As such, consistent with the amortization of other costs in the instant proceeding and the anticipated timing of the Company's next base distribution rate case, the Department finds that a ten-year amortization period is appropriate. Accordingly, the Department adjusts the Company's proposed unrecovered reserve adjustment from $115,269 to $57,634 (Exhs. ES-DPH/ANB-3 (Rev. 3), WP 22; DPU-ES 4-17, Att. at 51).

d. Conclusion

NSTAR Gas's proposed $37,328,792 depreciation expense is calculated by applying the accrual rates approved above to plant balances as of December 31, 2019 (Exhs. ES-DPH/ANB-1, at 89-90; ES-DPH/ANB-3 (Rev. 3), WP 22; ES-AG Stipulations, Table 1). As discussed in Section V.B.4.f, the Department has determined that the Company's cast-off rates for its proposed PBR Plan should be based on its test-year-end plant balances, and to exclude 2019 plant until the Company's first PBR adjustment. Accordingly, applying the approved accrual rates to the Company's plant balances as of December 31, 2018, and incorporating the aforementioned unrecovered reserve adjustment, the Department calculates a depreciation expense of $35,599,626 (Exhs. ES-DPH/ANB-3 (Rev. 3), WP 22; ES-JSS-2, at 50-51; DPU-ES 4-17, Att. at 50-51).

I. Uncollectible Expense

1. Introduction

During the test year, NSTAR Gas booked $4,473,592 in uncollectible expense related to its distribution service operations (Exh. ES-DPH/ANB-2 (Rev. 3), Sch. 20, at 2).[136] The Company proposes to decrease its test-year distribution-related uncollectible expense by $476,028 over the test-year level based on the application of an uncollectibles ratio of 1.5433 percent (Exh. ES-DPH/ANB-2 (Rev. 3), Sch. 20, at 2). The Company calculated the proposed distribution-related uncollectibles ratio by dividing its average net distribution-related write-offs for 2016 through 2018 of $3,624,302, by its average retail distribution service revenues for that same period of $234,838,744 (Exh. ES-DPH/ANB-2 (Rev. 3), Sch. 20, at 2).[137] This calculation resulted in an uncollectibles ratio of 1.5433 percent (Exh. ES-DPH/ANB-2 (Rev. 3), Sch. 20, at 2). The Company then multiplied the uncollectibles ratio of 1.5433 percent by test-year, normalized distribution service revenues of $259,024,532, to arrive at an uncollectible expense of $3,997,564, which represented a $476,028 decrease from the $4,473,592 in uncollectible expense booked during the test year (Exh. ES-DPH/ANB-2 (Rev. 3), Sch. 20, at 2).

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136 Bad debt expense is used synonymously with uncollectible expense.

137 Net write-offs associated with hardship receivables of ($272,336) for 2016, ($193,028) for 2017, and ($130,687) for 2018 as well as cost of gas write-offs of ($2,971,729) for 2016, ($2,366,956) for 2017, and ($3,346,619) for 2018 are excluded from the Company’s calculation of the three-year average uncollectibles write-off calculation (Exhs. ES-DPH/ANB-1, at 105; ES-DPH/ANB-3, Work Paper 20 (Rev. 3), at 2).

The Company also calculated an uncollectible expense associated with the proposed revenue increase (Exh. ES-DPH/ANB-2 (Rev. 3), Sch. 4). The Company multiplied the uncollectibles ratio of 1.5433 percent by its proposed revenue increase of $34,970,916 to arrive at a proposed uncollectible expense adjustment of $539,711 (Exh. ES-DPH/ANB-2 (Rev. 3), Sch. 4).[138]

2. Positions of the Parties

a. Attorney General

The Attorney General contends that the Company has attempted to change the test year to 2019 during the course of this proceeding (Attorney General Brief at 9; Attorney General Reply Brief at 2-3). The Attorney General argues that if the Department allows NSTAR Gas to use a 2019 test year, then the Department should recalculate the uncollectibles ratio using net write-offs for 2017 through 2019 instead of the proposed uncollectibles ratio calculated using net write-offs for 2016 through 2018 to conform to Department precedent (Attorney General Brief at 39; Attorney General Reply Brief at 2-3).

b. Company

The Company argues that its uncollectible expense calculation is consistent with Department precedent and, therefore, should be approved (Company Brief at 177). In response to the Attorney General's argument, the Company asserts that the Attorney General is attempting to deprive customers of the benefits of the PBRM while picking and choosing

138 Minor discrepancies in any of the amounts appearing in this Section are due to rounding.

which elements to update based on the results (Company Reply Brief at 39, 42). Therefore, the Company argues we should reject the Attorney General's request (Company Brief at 71; Company Reply Brief at 39, 42).

3. Analysis and Findings

The Department permits companies to include for ratemaking purposes a representative level of uncollectible revenues as an expense in cost of service. D.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 uncollectible expense. D.P.U. 96-50 (Phase I) at 71, citing Commonwealth Electric Company, D.P.U. 89-114/90-331/91-80, at 139 (1991). A company's uncollectible expense ratio is derived by dividing the three-year distribution-related net write-offs by the distribution-related billed revenues for the same period. This uncollectible expense 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. D.P.U. 07-71, at 106-109; D.P.U. 96-50 (Phase I) at 71.

We find that the method used by NSTAR Gas to calculate its distribution-related uncollectible expense is consistent with Department precedent. D.P.U. 15-80/D.P.U. 15-81, at 161; D.P.U. 14-150, at 160; D.P.U. 07-71, at 106-109. However, the Attorney General argues that if the Department allows 2019 costs into the cost of service then it follows that the Department should recalculate the uncollectible expense ratio using net write-offs for 2017 through 2019 (Attorney General Brief at 39-42). We find that the method proposed by the Attorney General to calculate the Company's distribution-related uncollectible expense is also consistent with Department precedent. D.P.U. 89-114/90-331/91-80 (Phase One) at 138-139 (with difficult economy contributing to greater amount of uncollectibles, Department accepted more recent three-year period for calculating uncollectible expense than included in the company's initial filing); Western Massachusetts Electric Company, D.P.U. 85-270, at 179-180 (in updating calculation of uncollectible expense, Department accepted three fiscal years of data where the data was more recent than calendar-year data) (1986). Based on our decision above in Section V.B.4.f to allow the Company to include 2019 and 2020 capital additions and other associated adjustments in its PBRM and the Department's allowance of post-test year data, the Department shall calculate the Company's uncollectible expense using the 2017 through 2019 write-offs.[139]

To calculate the uncollectible expense ratio, we divide the 2017 through 2019 net write-off amount of $3,722,241 by the Company's average retail distribution service revenues of $251,000,781 for that same period resulting in an uncollectible expense ratio of 1.5029 percent (RR-AG-2, Att.). Then, applying the 1.5029 percent uncollectible expense ratio to the normalized test-year distribution service revenues of $259,024,532 produces an uncollectible expense of $3,892,828 (Exh. ES-DPH/ANB-2 (Rev. 3), Sch. 20, at 2). The Company proposed $3,997,564 in distribution-related uncollectible expense

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139 By revising the three-year period for calculating uncollectible expense, the Department is not adopting a 2019 test year for this case.

(Exh. ES-DPH/ANB-2 (Rev. 3), Sch. 20, at 2). Accordingly, the Department will decrease the Company's cost of service by $104,736.[140]

The Company calculated an uncollectible expense of $539,711 associated with its proposed revenue increase of $34,970,916 (Exh. ES-DPH/ANB-2 (Rev. 3), Sch. 1, at 1 and Sch. 4). Applying the same adjusted 1.5029 percent uncollectible expense ratio set forth above to the revenue increase approved in this case of $22,771,124, results in an uncollectible expense in the amount of $351,430. Accordingly, the Department further decreases the Company's proposed cost of service by $235,558.

### J. Inflation Allowance

#### 1. Introduction

NSTAR Gas proposes an inflation allowance of $616,707 (Exhs. ES-DPH/ANB-1, at 87; ES-DPH/ANB-2 (Rev. 3), Sch. 21; ES-DPH/ANB-3 (Rev. 3), WP 21, at 1).[141] To arrive at this proposed adjustment, the Company first calculated its inflation factor using the gross domestic product implicit price deflator ("GDPIPD") as sourced from the Bureau of Economic Analysis and Moody's Analytics (Exhs. ES-DPH/ANB-1, at 87-88; ES-DPH/ANB-3, WP 21, at 1; DPU-ES 4-40). With updated data, NSTAR Gas calculated the projected change in the GDPIPD from the midpoint of the test year to the midpoint of the

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140 $3,997,564 - $3,892,828 = $104,736

141 In its initial filing, NSTAR Gas proposed an inflation allowance of $1,021,253 (Exhs. ES-DPH/ANB-1, at 87; ES-DPH/ANB-2, Sch. 21). NSTAR Gas subsequently revised its proposed inflation allowance based on updated expense reporting, a revised inflation factor, and a stipulated adjustment (Exhs. ES-DPH/ANB-2 (Rev. 3), Sch. 21; ES-DPH/ANB-2 (Rev. 3), WP 21; ES-AG Stipulations at 5).

rate year as 3.317 percent (Exhs. ES-DPH/ANB-1, at 88; ES-DPH/ANB-3 (Rev. 3), WP 21, at 1).[142]

Next, NSTAR Gas took its adjusted test-year O&M expense of $72,503,159, and subtracted $53,910,857, which represents adjusted test-year expenses associated with the various O&M expense categories for which NSTAR Gas seeks separate adjustments (Exh. ES-DPH/ANB-3 (Rev. 3), WP 21).[143] Finally, NSTAR Gas multiplied the 3.317 percent inflation factor by $18,592,302 in adjusted test-year residual O&M expenses to arrive at a proposed inflation allowance of $616,707 (Exhs. ES-DPH/ANB-2 (Rev. 3), Sch. 21; ES-DPH/ANB-3 (Rev. 3), WP 21).

2. Positions of the Parties

The Company contends that it calculated an inflation allowance to recognize the expected changes in cost that will occur between the end of the test year and the midpoint of the rate year (Company Brief at 234, citing Exh. ES-DPH/ANB-1, at 87). NSTAR Gas alleges that the proposed inflation allowance applies only to expenses that have not been separately adjusted (Company Brief at 234, citing Exh. ES-DPH/ANB-1, at 87). The Company also describes its efforts to contain costs, including a strictly managed budget

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142 In its initial filing, NSTAR Gas calculated the projected change in the GDPIPD from the midpoint of the test year to the midpoint of the rate year as 5.476 percent (Exhs. ES-DPH/ANB-1, at 88; ES-DPH/ANB-3, WP 21, at 1).

143 NSTAR Gas seeks separate adjustments for the following expense categories: payroll, variable compensation, dues and memberships, employee benefits, enterprise IT projects, insurance, injuries and damages, lease, postage, and uncollectibles (Exh. ES-DPH/ANB-3 (Rev. 3), WP 21).

process, annual goals for cost reductions, negotiations with vendors, reduced travel and conference attendance, increased efficiencies, and investment in reliability of the system (Company Brief at 235-237, citing Exhs. ES-MPS-1, at 7-10; DPU-ES 4-54; DPU-ES 4-56; DPU-ES-18-3; DPU-ES 23-12; AG 1-52; AG 13-29). No other party commented on the 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.P.U. 17-170, at 147; D.P.U. 17-05, at 328; D.P.U. 15-155, at 314. 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. D.P.U. 1720, at 19-21; Commonwealth Electric Company, D.P.U. 956, at 40 (1982). 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. 17-170, at 147; D.P.U. 17-05, at 329; D.P.U. 15-155, at 314. 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. 17-170, at 147; D.P.U. 17-05, at 329; D.P.U. 15-155, at 314-315.

NSTAR Gas calculated its inflation allowance from the midpoint of the test year to the midpoint of the rate year, using the most recent GDPIPD as an inflation measure (Exhs. ES-DPH/ANB-1, at 87; ES-DPH/ANB-3, WP 21 (Rev. 3), at 1). This calculation method and use of GDPIPD are consistent with Department precedent. D.P.U. 17-170, at 147; D.P.U. 17-05, at 330; D.P.U. 15-155, at 314-315; D.P.U. 14-150, at 246.

With respect to cost containment, the Company notes that opportunities to minimize cost increases exist across its operations and that these opportunities can be realized using a tightly controlled budgeting process (Exh. DPU-ES 18-03, at 1). NSTAR Gas has demonstrated a number of cost-containment measures that it has taken throughout the course of its regular operations, including the renegotiation of outside service contracts with vendors for improved pricing, reduced travel and conference attendance, improved efficiency of organizational structures by eliminating duplicity and overlap, and increased capital investments to improve system reliability and reduce maintenance costs (Exh. DPU-ES 23-12). The Company also introduced hybrid vehicles to lower fuel expense and leveraged call center resources across Connecticut, Massachusetts, and New Hampshire during peak times and emergencies to lower outside contractor costs (Exh. DPU-ES 23-12). Based on these considerations, the Department finds that the Company has implemented cost-containment measures sufficient to approve an inflation allowance.

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 test-year expense is also removed in its entirety from the inflation allowance. D.P.U. 17-170, at 148, D.P.U. 17-05, at 330; D.P.U. 15-155, at 316. As shown in Table 1, NSTAR Gas has removed test-year expenses associated with various O&M expense items that have either been separately adjusted for ratemaking purposes or are not subject to inflationary pressures, such as, but not limited to, payroll expense, dues and memberships, and insurance expense (Exh. ES-DPH/ANB-3 (Rev. 3), WP 21, at 1). As shown in Table 1, the $53,910,857 test-year expense associated with these items has been removed from NSTAR Gas's residual O&M expense calculation (Exhs. ES-DPH/ANB-1, at 87; ES-DPH/ANB-2 (Rev. 3), Sch. 21; ES-DPH/ANB-3 (Rev. 3), WP 21 at 1). The Department finds that NSTAR Gas has correctly excluded the O&M categories for which it seeks separate adjustments from the calculation of the inflation allowances.

Based on the above, the Department finds that an inflation allowance adjustment equal to the most recent forecast of GDPIPD for the period proposed by the Company, applied to NSTAR Gas's approved levels of eligible O&M expense, is appropriate. As shown in Table 1, below, the approved inflation allowance is $617,707.

**Table 1**

| | |
|---|---|
| **Normalized Test Year O&M Expense:** | $72,503,159 |
| **Less Company Adjustments:** | |
| Compensation: Payroll | $31,470,173 |
| Compensation: Incremental FTE Hires | - |
| Compensation: Variable Compensation | $3,366,683 |
| Dues and Memberships | $193,686 |
| Employee Benefits Costs | $5,489,758 |
| Enterprise IT Projects Expense[144] | $4,486,132 |
| Insurance Expense and Injuries and Damages | $972,391 |
| Lease Expense[145] | $2,505,247 |
| Postage Expense | $953,195 |
| Rate Case Expense | - |
| Uncollectibles Expense | $4,473,592 |
| **Total Company O&M Adjustments**: | $53,910,857 |
| Subtotal (Adjusted per Books Less Company Adjustments) | $18,592,302 |
| Residual O&M Expense | $18,592,302 |
| Inflation Factor from Midpoint of Test Year to Midpoint of Rate Year: | 3.317% |
| **Inflation Allowance:** | $616,707 |

144 The Department adjusted the Company's test year Enterprise IT Projects Expense in Section VIII.B.4. That adjustment, however, is not reflected in Table 1 because it would necessitate a corresponding adjustment to the normalized test year O&M expense of $72,503,159 and, thus, would result in no change to the approved inflation allowance.

145 The Department adjusted the Company's test year Lease Expense in Section VIII.3.d. That adjustment, however, is not reflected in Table 1 because it would necessitate a corresponding adjustment to the normalized test year O&M expense of $72,503,159 and, thus, would result in no change to the approved inflation allowance.

## IX. AMORTIZATION OF GOODWILL

### A. Introduction

In 1999, the Department approved a rate plan for Boston Edison Company, Cambridge Electric Light Company, Commonwealth Electric Company, and Commonwealth Gas Company (together, "NSTAR Companies") filed in conjunction with the BEC/ComEnergy merger. D.T.E. 99-19, at 1. The Department also approved the recovery of an acquisition premium[146] along with a 40-year amortization recovery period. D.T.E. 99-19, at 59. As of December 31, 1999, the total goodwill balance was reported as $490,023,538, of which $69,312,933 (or 14.14 percent) was allocated to NSTAR Gas (Exhs. ES-DPH/ANB-1, at 92; ES-DPH/ANB-4, Sch. 8, at 13-14).[147] The total goodwill balance included $5,992,297 in known and anticipated costs associated with the change-in-control provisions included in certain ComEnergy employment contracts that were in existence at the time of the merger (referred to in the goodwill calculation as "loss contingencies") (Exhs. ES-DPH/ANB-1, at 95; ES-DPH/ANB-4, Sch. 8, at 13, 20).

In 2014, as part of the first adjudicated base distribution rate case for the NSTAR Companies after the BEC/ComEnergy merger, the Department approved a base distribution rate increase for NSTAR Gas, which included the amortization of the Company's allocated

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146 An acquisition premium is the excess of the total purchase price or consideration paid in the transaction over the historical cost of the net assets of the entity acquired.

147 An acquisition premium is recorded as part of goodwill.

portion of the acquisition premium. D.P.U. 14-150, at 232-234.[148] In evaluating the total goodwill balance, the Department found that because loss contingencies represent predictions of future probabilities, this type of accounting entry does not represent an element of an acquisition premium that should be borne by ratepayers. D.P.U. 14-150, at 233. Accordingly, the Department excluded $5,992,297 in loss contingencies from the calculation of the acquisition premium attributable to NSTAR Gas. D.P.U. 14-150, at 232-234.[149] NSTAR Gas filed a motion for reconsideration of the Department's decision, and that motion is still pending. D.P.U. 14-150, NSTAR Gas's Motion for Reconsideration and Clarification at 4-13 (November 19, 2015).[150]

Subsequently, the Department had the opportunity to revisit the loss contingencies issue in D.P.U. 17-05, NSTAR Electric's most recent base distribution rate proceeding. In that matter, the Department determined that change-in-control payment provisions are often

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148 See D.P.U. 14-150, at 228-230 for a full procedural background related to this issue.

149 The Department also questioned whether one of ComEnergy's unregulated affiliates was improperly excluded from the calculation of an $11,881,441 basis adjustment attributable to the unregulated affiliates. D.P.U. 14-150, at 232. The Department did not adjust the goodwill balance, but rather, put NSTAR Gas (and, by inference, Eversource Energy) on notice that the calculation would be a subject of inquiry in NSTAR Gas's next base distribution rate proceeding. D.P.U. 14-150, at 232. Subsequently, when evaluating NSTAR Electric's amortization of goodwill in D.P.U. 17-05, the Department determined that the NSTAR Companies appropriately determined the fair market value of each of ComEnergy's nine unregulated affiliates and that "we no longer have the concern that we raised in D.P.U. 14-150, at 232." D.P.U. 17-05, at 292. Accordingly, we need not address this issue any further in the instant matter.

150 On the same date, NSTAR Gas filed a separate Motion to Reopen Evidentiary Record to provide documentation related to the goodwill computation.

found in employment contracts of key employees and are distinguishable from severance packages that may be offered to employees in a post-merger or post-acquisition setting. D.P.U. 17-05, at 293. Further, the Department noted that at the time of the BEC/ComEnergy merger, the NSTAR Companies estimated that three ComEnergy employees would qualify for change-in-control payments; however, based on the actual number of employees identified with change-in-control agreements and the timing of their exercise of these provisions, the total change-in-control payments ultimately paid out to ComEnergy employees was higher than the $5,992,297 estimate reported by the NSTAR Companies. D.P.U. 17-05, at 293. The Department also recognized that the provisions of Accounting Principles Board Opinion No. 16, Business Combinations, issued in August 1970, and Statement of Financial Accounting Standards No. 38, "Accounting for Pre-Acquisition Contingencies of Purchased Enterprises," issued in September 1980, both of which governed the transaction at that time, provide that these change-in-control payments should be included in the goodwill computation. D.P.U. 17-05, at 293. Based on these findings, the Department concluded that these change-in-control payments were appropriately part of the purchase price of ComEnergy, and that the $5,992,297 amount represented a conservative measure of the actual change-in-control payments made as part of the BEC/ComEnergy Merger. D.P.U. 17-05, at 294. Accordingly, the Department approved the inclusion of $5,992,297 in the calculation of NSTAR Electric's acquisition premium. D.P.U. 17-05, at 294.

B. Company Proposal

NSTAR Gas reports that as of December 31, 2018, it will have recovered $33,497,517 in goodwill amortization, leaving a remaining recoverable balance of $35,815,416 (Exh. ES-DPH/ANB-3, WP 23). NSTAR Gas adds to this balance deferred income taxes of $9,784,772 and a tax gross-up of $3,678,040[151] to produce a total goodwill regulatory asset of $49,278,228, as of the end of the test year (Exh. ES-DPH/ANB-3, WP 23).

NSTAR Gas states that the goodwill regulatory asset balance of $49,278,228 amortized over the remaining 248 months of the 40-year (or 480-month) amortization period approved in D.T.E. 99-19, results in an annual amortization of $2,384,440[152] (Exh. ES-DPH/ANB-3, WP 23). During the test year, NSTAR Gas booked $2,384,440 in goodwill amortization (Exh. ES-DPH/ANB-3, WP 23). Therefore, NSTAR Gas proposes to use its test year amortization expense to determine the revenue requirement in this proceeding.

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151 The goodwill amortization is not deductible for federal or Massachusetts income tax purposes. D.P.U. 14-150, at 230 n.137. Therefore, NSTAR Gas included a tax gross-up to recognize the appropriate tax treatment of the goodwill 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. ES-DPH/ANB-3, WP 23).

152 The mathematical total (i.e., $49,278,228/248 months * 12) yields an annual amortization of $2,384,430, though the Company's schedules reflect a total of $2,384,440 (Exh. ES-DPH/ANB-3, WP 23). The Department finds that the $10.00 discrepancy will have no appreciable impact on rates, and we accept $2,384,440 for purposes of setting rates.

On brief, the Company notes that in D.P.U. 17-05, the Department found that the change-in-control payments were appropriately part of the purchase price of COM/Energy and, therefore, properly included in the calculation of the acquisition premium (Company Brief at 245, citing D.P.U. 17-05, at 294). Therefore, consistent with the Department's findings in D.P.U. 17-05, NSTAR Gas argues that the Department should approve the Company's proposal (Company Brief at 246). No other party addressed the Company's amortization of goodwill resulting from the BEC/ComEnergy merger.

C. Analysis and Findings

Based on the record before us, and the Department's prior findings in D.P.U. 17-05, we conclude that it is appropriate to include $5,992,297 in loss contingencies in the calculation of the total balance of goodwill arising from the BEC/ComEnergy merger, a portion of which is allocated to NSTAR Gas (Exhs. ES-DPH/ANB-1, at 95-98; ES-DPH/ANB-4, Sch. 8; Tr. 8, at 1051-1057).[153] As noted above, as of the end of the test year, NSTAR Gas had recovered $33,497,517 in goodwill amortization, leaving a remaining recoverable balance of $35,815,416 (Exh. ES-DPH/ANB-3, WP 23). The Department has

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153 The Company states that the actual payments to the three departing ComEnergy executives was $5,861,107 (Exh. ES-DPH/ANB-1, at 95; Tr. 8, at 1055). The record also reveals that there were additional payments made to other departing executives that were not included in the initial estimate establishing the level of the acquisition premium, such that the total payments arising from the transaction as a whole exceeded the initial estimate of $5,992,297 (Tr. 8, at 1055). Given that the loss contingencies amount of $5,992,297 was recorded by the NSTAR Companies after the merger, reported to FERC, and previously approved by the Department in D.P.U. 17-05, the Department is satisfied that this amount is appropriate to account for the change-in-control payments associated with the BEC/ComEnergy merger (Exhs. ES-DPH/ANB-4, Sch. 8, at 13, 20; Tr. 8, at 1056).

reviewed the Company's calculation of its remaining recoverable balance, including the recovery of deferred income taxes and tax gross up, and we find that the calculation to be acceptable (Exh. ES-DPH/ANB-3, WP 23 (Rev. 3)). Accordingly, the Department accepts the Company's proposed annual amortization expense of $2,384,440.[154]

## X. EXOGENOUS COST PROPERTY TAX PROPOSAL

### A. Introduction

In NSTAR/Northeast Utilities Merger, D.P.U. 10-170-B at 2, 107 (2012), the Department approved a proposed settlement agreement ("Merger Settlement") to merge NSTAR Electric Company ("NSTAR Electric") and NSTAR Gas, along with their parent holding company, NSTAR, and Western Massachusetts Electric Company ("WMECo"), along with its parent holding company, Northeast Utilities.[155] As part of its decision, the Department approved a base rate freeze applicable to the distribution rates of NSTAR Electric, NSTAR Gas, and WMECo, so that base rates in effect on January 1, 2012, remained in place until January 1, 2016. D.P.U. 10-170-B at 18-19, 107.

Pursuant to Article II (5) of the Merger Settlement, NSTAR Gas may seek exogenous cost recovery of incremental property taxes incurred during the rate freeze (i.e., January 1,

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[154] NSTAR Gas acknowledges that approval of its proposal in the instant case will allow the Company to recover its full allocated share of the total goodwill balance, inclusive of $5,992,297 in loss contingencies (Tr. 8, at 1057). As such, we need not make any adjustments in this regard. Further, NSTAR Gas acknowledges that allowance of the Company's proposal will resolve this issue as it pertains to the Company's pending motion for reconsideration filed in D.P.U. 14-150 (Tr. 8, at 1057).

[155] Pursuant to 220 CMR 1.10(3), the Department incorporates by reference the Merger Settlement filed and approved in D.P.U. 10-170-B.

2012 through December 31, 2015) associated with the adoption by municipalities of the "reproduction cost new less depreciation" ("RCNLD") method[156] of assessing the value of personal property, provided that the incremental expense meets the minimum annual threshold for exogenous costs. The Merger Settlement provides that the dollar threshold for qualification as an exogenous factor in any calendar year covered by the Merger Settlement shall be determined by multiplying the total distribution revenues of that year by a factor of 0.003212 (Merger Settlement, Art. II (5)). The Merger Settlement is silent with respect to the method to be used to recover exogenous costs.

B. Company Proposal

NSTAR Gas states that it has incurred $5,005,413[157] in incremental property taxes from 2012 through 2015 as a result of the City of Worcester's ("Worcester") and Town of Westborough's ("Westborough") adoption of the RCNLD valuation method

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156 The RCNLD method uses the property tax expense as reported on the town's most recent property tax bills, adjusted to recognize any changes in personal property valuations (Exh. ES-DPH/ANB-1, at 115). The RCNLD valuation method 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 v. The Board of Assessors of Boston, Docket Nos. F275055, F275056, at Appellate Tax Board 2009-1232 (December 16, 2009).

157 The exact amount of incremental property taxes is $5,005,412.88, of which $4,717,097.35 is attributable to Worcester and $288,315.53 is attributable to Westborough (Exh. DPU-ES 10-21, Att. (a)). In its direct testimony, the Company refers to the amount as $5,005,412 (Exh. ES-DPH/ANB-1, at 143, 146-147, 149). The total amount, however, is rounded to $5,005,413 in the Company's 2018 Annual Return and in the cost of service schedules provided in this proceeding (Exhs. ES-DPH/ANB-4, Sch. 3, at 27; ES-DPH/ANB-2, Sch. 23 (Rev. 3)). Hereinafter, the Department refers to the rounded amount.

(Exhs. ES-DPH/ANB-1, at 141, 143, 146-147; ES-DPH/ANB-2, Sch. 23 (Rev. 3); DPU-ES 10-21, Att. (a); DPU-ES 10-23, Att. (a) at 3-4; DPU-ES 25-1 & Atts.).[158] NSTAR Gas withheld paying portions of the incremental property tax levied by Worcester and Westborough[159] and sought abatements for the incremental tax amounts, but those requests were denied (Exhs. ES-DPH/ANB-1, at 142-143, 147; DPU-ES 10-21, Att. (a); DPU-ES 10-23, Att. (a) at 3-4; DPU-ES 10-25 (Supp.); DPU-ES 18-9, Att. (a); AG 30-1 & Atts.). Thereafter, NSTAR Gas appealed the abatement decisions to the Massachusetts Appellate Tax Board ("Appellate Tax Board") and those appeals are pending (Exhs. ES-DPH/ANB-1, at 143, 146; DPU-ES 19-8; DPU-ES 19-9; DPU-ES 19-10). NSTAR Gas states that if the Appellate Tax Board denies these appeals, the Company will evaluate the propriety of further appeals to the Massachusetts Court of Appeals (Exh. ES-DPH/ANB-1, at 149).

NSTAR Gas seeks to recover the $5,005,413 in incremental property taxes as an exogenous cost pursuant to the Merger Settlement (Exh. ES-DPH/ANB-1, at 140-141, 143,

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158 The Company notes that the exogenous cost provision of the Merger Settlement covers the calendar years 2012 through 2015, which corresponds to the fiscal periods July 2011 through June 2015 (Exh. DPU-ES 25-1). The Company seeks to recover incremental property taxes incurred in the calendar years 2012 through 2015 for municipal property tax billing purposes (Exh. DPU-ES 25-1).

159 The Company paid the incremental taxes for fiscal year 2012 but withheld $3,294,072.67 in taxes levied by Worcester for fiscal years 2013 through 2015 and $219,696.97 in taxes levied by Westborough for the same time period (Exhs. DPU-ES 10-21, Att. (a); DPU-ES 10-23, Att. (a) at 3-4; DPU-ES 10-25 (Supp.); DPU-ES 18-9, Att. (a)). These amounts do not include any interest on the withheld amounts, which the Company states is accruing at 14 percent annually (Exhs. ES-DPH/ANB-1, at 147; DPU-ES 10-25 (Supp.); DPU-ES 23-27 & Atts.).

149). The Company proposes to amortize the recovery of these costs over five years at an annual amount of $1,001,083[160] (Exhs. ES-DPH/ANB-1, at 149; ES-DPH/ANB-2, Sch. 23 (Rev. 3); DPU-ES 25-1 & Atts.). NSTAR Gas states that upon Department approval of the proposal, the Company will pay the outstanding tax liabilities to Worcester and Westborough and continue to pursue its appeals before the Appellate Tax Board (Exhs. ES-DPH/ANB-1, at 149; DPU-ES 10-25 (Supp.); Tr. 8, at 1068). Further, NSTAR Gas states that if it prevails on its appeals and receives tax abatements from the two municipalities, the Company will refund customers the incremental property tax amounts through the exogenous cost provision of its proposed PBR mechanism (Exhs. ES-DPH/ANB-1, at 149; DPU-ES 10-25 (Supp.); Tr. 8, at 1066).[161] As discussed further below, in D.P.U. 14-150, at 274, 278-282, the Department denied NSTAR Gas's first request to recover incremental property taxes associated with Worcester and Westborough, which at the time totaled $3,348,306.[162]

### C. Positions of the Parties

#### 1. Attorney General

The Attorney General argues that the Department should reject the Company's proposal because the incremental property taxes incurred in 2012, 2013, and 2014 do not

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160 In its direct testimony, the Company presents the annual amortization amount as $1,001,082, but uses a rounded amount of $1,001,083 in its cost of service schedules (Exhs. ES-DPH/ANB-1, at 149; ES-DPH/ANB-2, Sch. 23 (Rev. 3)). Hereinafter, the Department refers to the rounded amortization amount.

161 The Company's proposed PBRM is discussed in Section V.B.4 above.

162 This amount was attributable to years 2012, 2013, and 2014. D.P.U. 14-150, at 272.

exceed the exogenous cost threshold set forth in the Merger Settlement (Attorney General Reply Brief at 21-22). The Attorney General contends that only the incremental property taxes incurred in 2015 (i.e., $1,657,108), qualify for exogenous cost recovery (Attorney General Reply Brief at 22). In reaching this conclusion, the Attorney General appears to multiply the Company's total operating revenues for each relevant year (i.e., 2012 through 2015) by an exogenous cost factor of 0.003212 (Attorney General Reply Brief at 22). She asserts that, to the extent that the Department allows recovery of any of the Company's proposed property tax exogenous costs, the Department should reduce the recovery amount to $1,657,108, which amortized over five years results in an annual recovery of $331,421 (Attorney General Reply Brief at 22).

2. TEC

TEC argues that the Department must be wary of "setting precedents related to payment of aggressive property tax valuation methods," and must ensure that the Company continues to challenge the RCNLD valuation method in the courts (TEC Brief at 14). TEC asserts that the Company is best suited to protect its customers from any wrongfully applied or calculated property valuations (TEC Reply Brief at 2 n.2). TEC suggests that allowing the Company's proposal may lower its resolve to fight the assessments in court (TEC Brief at 14-15). According to TEC, the risk of protracted litigation serves as a deterrent to other municipalities from adopting aggressive valuation methods (TEC Brief at 15).

3. Company

As an initial matter, the Company argues that the Attorney General is mistaken about the exogenous cost threshold (Company Reply Brief at 51). The Company notes that the

Merger Settlement is clear that the threshold shall be determined by multiplying the total distribution revenues (and not total operating revenues) of a particular year covered by the Merger Settlement by a factor of 0.003212 (Company Reply Brief at 51, citing Merger Settlement, Art. II (5)). The Company asserts that using the calculation prescribed by the Merger Settlement, the exogenous cost threshold is satisfied for each relevant year (i.e., 2012 through 2015) (Company Reply Brief at 51-52, citing Exh. DPU-ES 10-24). Thus, the Company asserts that the Department should reject the Attorney General's recommendations (Company Reply Brief at 52).

Next, the Company argues that "changed circumstances" arising since D.P.U. 14-150 justify the renewal of its request to recover the incremental property taxes as exogenous costs (Company Brief at 128). In particular, the Company points to the lengthy appeals process undertaken by NSTAR Electric and the former WMECo to challenge incremental property taxes assessed by certain municipalities in their service areas (Company Brief at 128-129). NSTAR Gas contends that adverse decisions from the Appellate Tax Board and/or the Massachusetts appellate courts relative to some of the appeals filed by NSTAR Electric and WMECo, and continued inaction from the Appellate Tax Board relative to the remaining appeals filed by both electric operating companies, demonstrate that the appellate process is likely to be futile for the Company (Company Brief at 78, 128, citing Exhs. ES-DPH/ANB-1, at 144-145; DPU-ES 10-21; DPU-ES 10-25 (Supp.)). Further, the Company notes that the Massachusetts Department of Revenue ("DOR") recently confirmed the validity of a municipality's ability to change the method of property valuation (Company Brief at 41, 78, citing Exh. DPU-ES 12-4).

NSTAR Gas argues that these circumstances demonstrate that the Company's pending appeals before the Appellate Tax Board are unlikely to succeed, any potential further appeals to the SJC are years away, and there is no guarantee that the SJC will hear the appeals given that it already has ruled on previous similar appeals (Company Brief at 129). In sum, the Company asserts that there is nothing to suggest that the outcome of its appeals will be any different than the outcome of the NSTAR Electric and WMECo appeals to date (Company Brief at 129). Thus, NSTAR Gas submits that it must pay the higher assessments, and the Company asserts that TEC's support for protracted legal challenges to the incremental taxes is "simply a waste of money, time, and effort" (Company Brief at 78, citing TEC Brief at 14-15).

NSTAR Gas also notes that annual interest at 14.0 percent continues to accrue for some of the unpaid incremental property tax balances (Company Brief at 129-130, citing Exhs. ES-DPH/ANB-1, at 147; DPU-ES 10-23). The Company contends that because the potential to prevail in the litigation process is diminishing, the continued payment of substantial interest costs on the outstanding tax expense is not warranted or appropriate (Company Brief at 130, citing Exhs. ES-DPH/ANB-1, at 147; DPU-ES 23-27). Further, the Company argues that because any appeals to the SJC may be years away, and the incremental taxes in dispute relate to years 2012 through 2015, there is a "substantial intergenerational equity issue" due to the passage of time and that customers who ultimately may pay these expenses will be different than the customers at the time the expenses were incurred (Company Brief at 130, citing Exh. ES-DPH/ANB-1, at 149).

Based on the above considerations, NSTAR Gas argues that it has developed and proposed a narrowly tailored means to address the incremental property taxes that protects ratepayer interests and alleviates some of the financial burden on the Company associated with the disputed tax assessments (Company Brief at 131). Accordingly, NSTAR Gas asserts that the Department should approve the Company's proposal (Company Brief at 131).

D. Analysis and Findings

In D.P.U. 14-150, at 278-282, the Department denied the Company's first request to recover incremental property taxes pursuant to the Merger Settlement. The Department determined that because the Company still was engaged in the appeals process after the denials of its tax abatement requests, we were unable to assess whether at the end of the appeals process there would be any incremental taxes and, if so, whether the amounts would be above the annual threshold subject to recovery from ratepayers as exogenous costs. D.P.U. 14-150, at 280. As such, the Department decided not to consider NSTAR Gas's request for recovery of incremental property taxes as an exogenous cost at that time, and instead determined that, once all appeals were exhausted, the Company should file a separate petition seeking exogenous cost recovery of any incremental property tax assessed using the RCNLD valuation method through the year ending December 31, 2015. D.P.U. 14-150, at 280-281.

Since the Department's decision in D.P.U. 14-150, the Company's challenges to the incremental taxes levied by Worcester and Westborough have not progressed. NSTAR Gas's appeals to the Appellate Tax Board, including the appeals that were pending at the time of the Department's decision in D.P.U. 14-150, remained pending at the close of the evidentiary hearings in this case (Exhs. ES-DPH/ANB-1, at 143, 146; DPU-ES 19-8; DPU-ES 19-9; DPU-ES 19-10). The timeframe for additional appeals through the Massachusetts court system is unknown.

Regarding such further appeals, NSTAR Gas argues that decisions from the SJC and Massachusetts Appeals Court suggest that the Company is unlikely to succeed on the merits of its tax assessment challenges (Company Brief at 41, 78, 128-129, citing Exhs. ES-DPH/ANB-1, at 144-145; DPU-ES 10-21; DPU-ES 10-25 (Supp.); DPU-ES 12-4). While the Department will not speculate as to the outcome of any future appeals filed by NSTAR Gas, we acknowledge that past court decisions relative to the City of Boston's assessment of personal utility property have not been favorable to other utilities. Specifically, in 2011, the SJC upheld a decision by the Appellate Tax Board that approved the City of Boston's assessment of Boston Gas's personal utility property based on weighing net book value equally with RCNLD. Boston Gas Company v. Board of Assessors, 458 Mass. 715, 729, 739-740 (2011). More recently, in a Rule 1:28 Memorandum Decision, the Massachusetts Appeals Court upheld the same assessment method used by the City of Boston as it pertained to NSTAR Electric's personal utility property. NSTAR Electric Company v. Assessors of Boston, 94 Mass. App. Ct. 1123 (2019). NSTAR Electric appealed to the SJC, which declined the application for further appellate review. NSTAR

Electric Company v. Assessors of Boston, 482 Mass. 1102 (2019).

In addition to these decisions, we also recognize that, on March 26, 2019, the DOR issued a Local Finance Opinion detailing a change in guidance from the Bureau of Local Assessment ("BLA") on the appropriate method of valuation for purposes of local property tax assessment (Exh. DPU-ES 10-21, Att. (e)). In the opinion, the BLA notes that, based on the aforementioned court decisions, it would accept a valuation method that gives equal weight to personal utility property's net book value and the property's RCNLD (Exh. DPU-ES 10-21, Att. (e) at 3).

The Department has given careful consideration to NSTAR Gas's proposal, the various arguments raised in support of the proposal, and the positions of the Attorney General and TEC. The Merger Settlement expressly allows the Company to seek recovery of the incremental tax amounts associated with the change in property valuation (Merger Settlement, Art. II (5)). As noted above, the Department's denial of the Company's prior request for recovery was based on the ongoing appeals process of the tax abatement denials before the Appellate Tax Board. D.P.U. 14-150, at 280-281. Given the continued pendency of those appeals, the uncertainty as to the progression of future appeals, and the treatment of the RCNLD method by the Massachusetts appellate courts and the DOR, the Department is persuaded that the Company no longer needs to exhaust all of its appeals before seeking exogenous cost recovery of incremental property taxes pursuant to the Merger Settlement. Rather, we conclude that it is reasonable and appropriate for the Company to begin to recover the incremental property taxes associated with Worcester and Westborough for 2012 through 2015. We find that allowing recovery of incremental property taxes at this time is consistent with the Merger Settlement and will mitigate future expenses (i.e., annual interest on the outstanding incremental tax balances) incurred in pursuing the appeals, as the Company will pay the outstanding tax liabilities to Worcester and Westborough.

In this regard, we acknowledge TEC's concern that allowing the Company's proposal in this case may lower its resolve to fight the assessments in court (TEC Brief at 14-15). To date, NSTAR Gas has taken appropriate steps to challenge the Worcester and Westborough assessments by seeking abatements and appealing the abatement denials to the Appellate Tax Board (Exhs. ES-DPH/ANB-1, at 142-143, 147; DPU-ES 10-21, Att. (a); DPU-ES 10-23, Att. (a) at 3-4; DPU-ES 10-25 (Supp.); DPU-ES 18-9, Att. (a); DPU-ES 19-8; DPU-ES 19-9; DPU-ES 19-10; AG 30-1 & Atts.). Further, the Company represents that it will continue to pursue the appeals with the Appellate Tax Board and then evaluate the propriety of future appeals (Exh. ES-DPH/ANB-1, at 149). As a public utility, the Company must pursue all reasonable and prudent avenues to protect ratepayer interests, including litigation and other advocacy efforts if warranted. See, e.g., Boston Edison Company, Cambridge Electric Light Company, Commonwealth Electric Company, D.T.E./D.P.U. 06-107-B at 57-58 (2009); Western Massachusetts Electric Company, D.T.E. 04-40/D.T.E. 04-109/D.T.E. 05-10, at 5-6 (2006); 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). We expect the Company's decision making with respect to future appeals will be consistent with this standard and will take into account all relevant considerations existing at the time of its decision.

Additionally, the Attorney General argues that any recovery allowed by the Department should be limited to the incremental property taxes incurred in 2015, as only this amount exceeds the exogenous cost threshold set forth in the Merger Settlement (Attorney General Reply Brief at 21-22). We disagree. The basis for NSTAR Gas's proposal to recover incremental property taxes is rooted in the Merger Settlement (Merger Settlement, Art. II (5)). The Merger Settlement expressly provides that "[t]he dollar threshold for qualification as an exogenous factor in any calendar year covered by this Settlement Agreement shall be determined by multiplying the total <u>distribution revenues</u> of that year by a factor of 0.003212" (Merger Settlement, Art. II (5) (emphasis added)). The Attorney General's calculations are misplaced, as she appears to multiply the Company's total <u>operating revenues</u> for each relevant year by the exogenous cost factor (Attorney General Reply Brief at 22). The Company provided the total distribution revenues used to calculate the exogenous cost thresholds for the years 2012 through 2015 (Exhs. DPU-ES 18-8 & Atts.; DPU-ES 10-24 & Att.; DPU-ES 25-1, Atts.). The Department finds that the incremental property taxes assessed in each year from 2012 through 2015 exceed the exogenous cost threshold for each respective year (Exhs. DPU-ES 18-8 & Atts.; DPU-ES 10-21, Att. (a); DPU-ES 10-23, Att. (a) at 3-4; DPU-ES 10-24 & Att.; DPU-ES 25-1, Atts.). Accordingly, we find that NSTAR Gas is eligible to recover incremental property taxes resulting from the RCNLD method assessed in each year from 2012 through 2015, consistent with the Merger Settlement.

The Merger Settlement does not describe the manner in which these costs shall be recovered (see Merger Settlement, Art. II (5)). As noted above, NSTAR Gas proposes to amortize the recovery of $5,005,413 in incremental property taxes over five years at an annual amount of $1,001,083 (Exhs. ES-DPH/ANB-1, at 149; ES-DPH/ANB-2, Sch. 23 (Rev. 3); DPU-ES 25-1 & Atts.). In Section V.B.4, above, the Department approved a PBRM for NSTAR Gas with a ten-year term. As such, the Department finds that it is reasonable and appropriate to amortize the recovery of the incremental property taxes over the same term as the PBRM. To the extent that the Company recovers any or all of the incremental property taxes as a result of the appeals process, it shall refund customers the incremental property tax amounts through the exogenous cost provision of the PBRM (Exhs. ES-DPH/ANB-1, at 149; DPU-ES 10-25 (Supp.); Tr. 8, at 1066).

Finally, the Department recognizes that it previously declined to allow proposals submitted by other utilities to recover incremental property taxes arising from the RCNLD method. See, e.g., Boston Gas Company and Colonial Gas Company, D.P.U. 17-170, at 177-179 (2018); NSTAR Electric Company and Western Massachusetts Electric Company, D.P.U. 17-05, at 523-525 (2017); Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 15-155, at 324-326 (2016); Bay State Gas Company, D.P.U. 12-25, at 329-334 (2012). Our decision today is based on the specific circumstances of the instant case, including the status of the Company's appeals and the fact that the Merger Settlement provides for recovery of the foregoing incremental property taxes. The Department will continue to evaluate proposals from other utilities to recover incremental property taxes arising from the RCNLD method on a case-by-case basis.

Based on these considerations, the Department approves the Company's exogenous cost property tax proposal, subject to the modifications above. The Company shall amortize \$5,005,413 over a ten-year period for an annual amount of \$500,541. Accordingly, the Department will reduce the Company's proposed cost of service by \$500,542.

## XI. CAPITAL STRUCTURE AND RATE OF RETURN

### A. Introduction

NSTAR Gas proposed a 7.60-percent weighted average cost of capital ("WACC") representing the rate of return to be applied on rate base to determine the Company's total return on its investment (Exh. ES-DPH/ANB-2 (Rev. 3), Sch. 30, at 1).[163] The Company's WACC is based on the following proposed elements: (1) capital structure consisting of 45.16-percent long-term debt and 54.84-percent common equity; (2) cost of long-term debt of 4.14 percent; and (3) rate of return on common equity ("ROE")[164] of 10.45 percent (Exh. ES-DPH/ANB-2 (Rev. 3), Sch. 30, at 1-2).

Initially, the Attorney General proposed a 6.48-percent WACC based on the following proposed components: (1) capital structure that consists of 48.33-percent long-term debt and 51.67-percent common equity; (2) cost of long-term debt of 4.33 percent; and (3) ROE of 8.5 percent (Exh. AG-JRW at 5). Subsequently, the Attorney General proposed a

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163 Minor discrepancies in any of the amounts appearing in this section are due to rounding.

164 The terms ROE and cost of equity are used interchangeably throughout this section.

6.74-percent WACC based on the following proposed components: (1) capital structure that consists of 48.33-percent long-term debt and 51.67-percent common equity; (2) cost of long-term debt of 4.31 percent[165]; and (3) ROE of 9.00 percent (Exhs. AG-JRW at 5-6, 38-39; AG-JRW-1; AG-JRW-Surrebuttal at 38-39).[166]

DOD-FEA proposed an alternate WACC based on the Company's proposed capital structure and cost of debt (Exhs. DOD-CCW-1, at 3; DOD-CCW-19, at 2). DOD-FEA proposed a 7.06-percent WACC developed using a 9.30-percent ROE (Exhs. DOD-CCW-19, at 2; DOD-CCW-Surrebuttal at 13).

Below, we examine (1) the Company's capital structure and cost of debt; (2) the proxy group selections used by the parties in supporting their proposed ROEs; (3) the modeling used by the parties supporting their proposed ROEs; and (4) the appropriate ROE.

B. <u>Capital Structure</u>

1. <u>Company's Proposal</u>

As of December 31, 2018, NSTAR Gas reported a capitalization consisting of $384,174,201 in long-term debt and $445,646,596 in common equity (Exhs. ES-DPH/ANB-1 at 7; ES-DPH/ANB-2, Sch. 30, at 1). NSTAR Gas proposed an adjusted pro forma long-term debt balance of $523,354,300 to incorporate a retirement of $125,000,000 of

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165 The Attorney General proposed a long-term debt cost of 4.31 percent for the first time on brief (Attorney General Brief at 75).

166 The Attorney General submitted three exhibits with her cost of capital surrebuttal testimony marked as Rebuttal Exhibit JRW-1 through Rebuttal Exhibit JRW-3. We cite to these exhibits as JRW-Surrebuttal-1 through JRW-Surrebuttal-3.

Series N bonds as of January 1, 2020, an issuance of $75,000,000 of Series Q bonds on July 25, 2019, and planned issuances of $75,000,000 of Series R bonds and $115,000,000 of Series S bonds on May 7, 2020 (Exhs. ES-DPH/ANB-1, at 124; ES-DPH/ANB-2, Sch. 30, at 2; DPU-ES 15-6).[167] In addition, NSTAR Gas proposed an adjusted pro forma common equity balance of $635,646,596 to incorporate a capital contribution of $190,000,000 to match the Company's long-term debt issuances in 2020 (Exhs. ES-DPH/ANB-1, at 124-125; ES-DPH/ANB-2 (Rev. 3), Sch. 30, at 1; AG 7-11). NSTAR Gas's adjustments result in a $1,159,000,896 total capitalization composed of 45.16-percent long-term debt and 54.84-percent common equity (Exh. ES-DPH/ANB-2 (Rev. 3), Sch. 30, at 1).

2. Attorney General Proposal

The Attorney General proposed a capital structure consisting of 48.33-percent long-term debt and 51.67-percent common equity (Exh. AG-JRW at 38-39 & Table 3). The Attorney General recommended an imputed common equity ratio based on the average common equity ratio approved by state utility commissions during 2018 and 2019, excluding states that include cost-free capital in utility capital structures (Exh. AG-JRW at 38).

3. Positions of the Parties

a. Attorney General

The Attorney General asserts that she proposed an imputed capital structure because NSTAR Gas's requested capital structure includes a common equity ratio that is higher than

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167 During the proceeding, NSTAR Gas revised its proposed long-term debt balance from $523,193,474 to $523,354,300 based on revised debt issuance dates (Exhs. ES-DPH/ANB-2 (Rev. 1), Sch. 30, at 2; DPU-ES 15-6).

the average common equity ratios that are (1) employed by the proxy group, (2) approved for gas distribution companies, and (3) used by the Company's parent, Eversource (Attorney General Brief at 66). The Attorney General contends that when an actual capital structure contains a high equity ratio a regulator's options are (1) to impute a more reasonable capital structure to reflect the imputed capital requirements or (2) to recognize the downward impact on the financial risk of the utility and authorize a lower ROE (Attorney General Reply Brief at 26).[168] The Attorney General argues that the appropriate comparison to NSTAR Gas's capitalization is to the holding companies in the proxy group rather than to the capital structures of other distribution companies because holding companies have more debt and less equity than their operating utilities (Attorney General Reply Brief at 26-27). Further, the Attorney General argues that holding companies should be used to estimate an equity cost for NSTAR Gas because operating companies do not have common stock being traded in the open market (Attorney General Reply Brief at 27). Lastly, the Attorney General avers that the Department has continuously allowed Eversource to employ double leverage by approving common equity ratios for Eversource's subsidiaries that are much higher than their parent's common equity ratio (Attorney General Reply Brief at 27, <u>citing</u> Exh. AG-JRW-Surrebuttal at 28-30).

b. <u>Company</u>

The Company argues that the Attorney General's recommended capital structure violates the Department's standard that a utility's test-year-end capital structure allowed for

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168 We discuss the Attorney General's ROE proposals in Section XI.E.

known and measurable changes shall be used unless it deviates substantially from sound utility practice (Company Brief at 363, citing D.P.U. 17-05, at 615-616; D.P.U. 15-155, at 343; D.P.U. 15-80/D.P.U. 15-81, at 250; Company Reply Brief at 62-65, citing D.P.U. 13-75, at 272-273). The Company maintains that its proposed common equity ratio does not deviate substantially from sound utility practices as evidenced by the Department's approval of similar common equity ratios for other gas distribution companies and the median common equity ratio of the operating companies in the proxy group (Company Brief at 364, 365, citing D.P.U. 15-150, at 8; D.P.U. 17-170, at 265-266; D.P.U. 19-131, at 9; Exhs. ES-RBH-Rebuttal-1, at 83; ES-RBH-Rebuttal-18). Further, the Company asserts that its proposed common equity ratio is comparable to that recently approved for other gas utilities in the nation and utility commissions have recently begun to adopt higher equity ratios to offset the negative impact on utilities' cash flows as a consequence of federal tax reform (Company Brief at 365, citing Exh. ES-RBH-Rebuttal-1, at 87).

The Company also contends that the Department should only compare NSTAR Gas's capital structure to that of other operating companies because operating companies have comparable operations and assets, while holding companies operate differently and have different types of assets (Company Brief at 364, citing Exh. ES-RBH-Rebuttal, at 84). Finally, the NSTAR Gas argues that Eversource's higher common equity ratio is irrelevant because it is a widely accepted regulatory practice to treat distribution companies as stand-alone entities (Company Brief at 365-366, citing Exh. ES-RBH-Rebuttal-1, at 88; D.P.U. 13-75, at 272-276).

4. Analysis and Findings

A company's capital structure typically consists of long-term debt, preferred stock,[169] 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. D.P.U. 07-71, at 122; D.T.E. 03-40, at 319; D.T.E. 01-42, at 18; South Egremont Water Company, D.P.U. 86-149, at 5 (1986). The WACC is used to calculate the rate of return, which is applied to the company's rate base as part of the revenue requirement established by the Department, and it is made up of three components: (1) the cost of the company's long-term debt; (2) the cost of the company's preferred stock; and (3) the ROE set by the Department. 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 typically will accept a company's test-year-end capital structure, allowing for known and measurable changes. D.T.E. 03-40, at 323-324; D.P.U. 88-67 (Phase I) at 174; Colonial Gas Company, D.P.U. 84-94, at 50 (1984). Within a broad range, the Department will defer to the management of a utility in decisions regarding the appropriate capital structure, unless the capital structure deviates substantially from sound utility practice. Mystic Valley Gas Company v. Department of Public 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) (a company's capital structure

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169 NSTAR Gas's capital structure does not include preferred stock.

which is composed entirely of common equity with no long-term debt varies substantially from usual utility practice); see also Cambridge Electric Light Company, D.P.U. 20104, at 42 (1979).

On January 27, 2020, the Department approved a total of $270,000,000 of long-term debt issuances for the Company. NSTAR Gas Company, D.P.U. 19-118 (January 27, 2020). On May 7, 2020, the Company issued a total of $190,000,000 of Series R and Series S long-term bonds (Exh. ES-DPH/ANB-2 (Rev. 3), Sch. 30, at 2). 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, Inc., 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. NSTAR Gas received a capital contribution of $190,000,000 from its parent company, Eversource, to match the amount of the May 7, 2020 long-term debt issuances (Exh. AG 7-11, Att. (b)). The Department finds that this capital contribution represents a known and measurable adjustment to the Company's test-year end common equity balance and we accept this adjustment to NSTAR Gas's capital structure. Fitchburg Gas and Electric Light Company, D.P.U. 07-71, at 122 (2008).

The Department does not consider that the Company's common equity ratio to be so weighted towards common equity as to deviate substantially from sound utility practice or to impose an unfair burden on consumers. Mystic Valley Gas Company v. Department of Public Utilities, 359 Mass. 292, 301-302 (1971). Although NSTAR Gas's common equity ratio may be somewhat higher than those of other regulated gas utilities, that fact alone does not warrant the imputation of a hypothetical capital structure. Bay State Gas Company, D.P.U. 12-25, at 388 (2013); New England Gas Company, D.P.U. 08-35, at 190-191 (2009); Nantucket Electric Company, D.P.U. 91-106/138, at 97 (1991). Moreover, while the Company's common equity ratio differs from that of its parent company, NSTAR Gas and Eversource are distinctly separate legal entities, each with different operations and capital requirements (Exh. AG 1-2 (Supp.), Att. (1)(f)). In view of these differing operations, the Department finds that NSTAR Gas's capital requirements differ from those of Eversource and, therefore, it would be inappropriate to rely on Eversource's capital structure in determining that of the Company. Bay State Gas Company, D.P.U. 12-25, at 388 (2013). Accordingly, we decline to adopt the imputed capital structure recommended by the Attorney General.

The Company's proposed long-term debt balance of $523,354,300 is based on a "carrying value" of the underlying securities, which represents the net proceeds associated with its various debt issuances (Exh. ES-DPH/ANB-2 (Rev. 3), Sch. 30, at 2). The Department's long-standing policy is not to deduct issuance costs from either long-term debt or preferred stock balances, but rather to base a company's capitalization on the face value of the underlying securities.[170] Massachusetts Electric Company, D.P.U. 92-78, at 91-92

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170 As noted below, issuance costs associated with these instruments are recovered over the life of the issuance through an adjustment to the coupon rate. Massachusetts Electric Company, D.P.U. 92-78, at 91-92 (1992); Boston Edison Company, D.P.U. 86-71, at 12 (1986).

(1992); The Berkshire Gas Company, D.P.U. 90-121, at 159-161 (1991). Therefore, the Department will base the Company's long-term debt balance on the $525,000,000 face value of the underlying securities.

Based on the foregoing analysis, the Department uses a long-term debt balance of $525,000,000 and a common equity balance of $635,646,596 to determine NSTAR Gas's capital structure. As shown on Schedule 5 of this Order in Section XVI below, the use of these balances produces a capital structure consisting of 54.77-percent common equity and 45.23-percent long-term debt, which we consider to be consistent with sound utility practice.

C. Cost of Debt

1. Company's Proposal

In the initial filing, NSTAR Gas calculated a cost of long-term debt of 4.33 percent produced by dividing $22,630,000 in annual interest expense and amortization of premiums by the net carrying value of its long-term debt of $523,193,000, consisting of $525,000,000 in face value of its long-term bonds outstanding less $1,807,000 in carrying value costs (Exh. ES-DPH/ANB-2, Sch. 30, at 2). The Company adjusted its embedded cost of long-term debt from 4.33 percent to 4.14 percent during the course of the proceeding, to recognize a lower annual interest and amortization expense resulting from the issuance of $75 million and $115 million of Series R and S long-term bonds, respectively, on May 7, 2020 (Exhs. ES-DPH/ANB-2 (Rev. 3), Sch. 30, at 2; DPU-ES 15-6). The Company derived this embedded cost rate by dividing the adjusted annual interest and amortization expense by the adjusted (pro forma) net carrying value of the long-term debt as described below (Exh. ES-DPH/ANB-2 (Rev. 3), Sch. 30, at 2).

2. Positions of the Parties

a. Attorney General

The Attorney General asserts that the Company inappropriately subtracted the issuance costs from the principal amount of long-term debt outstanding to determine the embedded cost rate of the Company's long-term debt (Attorney General Brief at 75, citing Exh. ES-DPH/ANB-2, Sch. 30, at 2). According to the Attorney General, the Company's calculation effectively provides NSTAR Gas a return on the unamortized balance of issuance costs in violation of Department precedent (Attorney General Brief at 75).

The Attorney General asserts that the appropriate treatment of issuance costs is to amortize the issuance costs over the term of the debt issuance without a return on any unamortized balance (Attorney General Brief at 75, citing D.P.U. 92-78, at 91-92; D.P.U. 86-71, at 12). The Attorney General recommends that the Department correct the Company's calculation of the embedded cost of long-term debt by not subtracting the issuance costs from the principal balance of long-term debt outstanding (Attorney General Brief at 75).

b. Company

The Company summarizes its cost of long-term debt calculation (Company Brief at 367, citing Exh. ES-DPH/ANB-1, at 125-126). The Company claims that net debt proceeds must be used in the denominator of the cost of long-term debt for NSTAR Gas to earn a just and reasonable return (Company Brief at 367, citing Exhs. ES-DPH/ANB-1, at 125-126; ES-DPH/ANB-4, Sch. 9).

3. Analysis and Findings

The Department recognizes that 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. D.P.U. 92-78, at 91-92; D.P.U. 90-121, at 160-161.

NSTAR Gas appropriately considered issuance costs in its calculation of the total expense associated with debt issuances; however, the Company's calculations rely on a capitalization balance that reduces its long-term debt component by subtracting premiums and discounts and unamortized balances from its outstanding debt balance (Exh. ES-DPH/ANB-2 (Rev. 3), Sch. 30, at 2). The Department's long-standing policy with respect to the calculation of debt costs is to base the effective cost of debt on the face value of the outstanding debt, not its face value less issuance costs. D.P.U. 10-70, at 243-244; D.P.U. 95-40, at 80-81; D.P.U. 90-121, at 160-161; Boston Edison Company, D.P.U. 86-71, at 12 (1986). As noted above, the Department does not permit the deduction of issuance costs from either long-term debt or preferred stock balances when determining the level of capitalization for ratemaking purposes. Massachusetts Electric Company, D.P.U. 92-78, at 91-92 (1992); The Berkshire Gas Company, D.P.U. 90-121, at 159-161

(1991). By reducing its outstanding debt balance by these amounts, NSTAR Gas's calculation artificially inflates the Company's effective cost of debt. D.P.U. 14-150, at 324; D.P.U. 10-114, at 294; D.P.U. 90-121, at 160-161. The Company has not presented any evidence or argument to support a departure from long-established Department precedent. Therefore, the Department denies Company's methodology for calculating the cost of long-term debt.

Based on NSTAR Gas's most recent updates, NSTAR Gas's annual interest and amortization expense associated with long-term debt is $21,687,000 (Exh. ES-DPH/ANB-2 (Rev. 3), Sch. 30, at 2). This annual expense includes $5,418,000 in costs associated with the $190 million in long-term debt issued on May 7, 2020 (Exh. ES-DPH/ANB-2 (Rev.), Sch. 30 at 2). Dividing NSTAR Gas's annual interest and amortization expense of $21,687,000 by the principal amount of its adjusted proforma long-term debt of $525,000,000 produces a cost of long-term debt of 4.13 percent (see Exh. ES-DPH/ANB-2 (Rev. 3), Sch. 30 at 2). Therefore, the Department applies a cost of long-term debt of 4.13 percent

## D. Proxy Groups

### 1. Company's Proxy Group

As a wholly-owned subsidiary of Eversource, NSTAR Gas's common stock is not publicly traded (Exh. ES-RBH-1, at 14-15). NSTAR Gas presented its cost of equity analysis using the capitalization and financial statistics of a proxy group of seven publicly traded natural gas utilities (Exh. ES-RBH-1, at 14-17). The Company selected its proxy group from the companies classified as natural gas utilities by Value Line Investment Survey

("Value Line") (Exh. ES-RBH-1, at 15). From that group, the Company 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") or a comparable financial strength rating; and (3) have been covered by at least two utility industry equity analysts (Exh. ES-RBH-1, at 15-16). As part of this process, NSTAR Gas excluded (1) companies with regulated natural gas utility operating income comprising less than 60 percent of the total income for that company; (2) companies that do not consistently pay quarterly cash dividends; and (3) companies that are currently involved in merger activities or other significant transactions (Exh. ES-RBH-1, at 15-16).

2. Attorney General's Proxy Group

The Attorney General's proxy group comprises nine publicly traded natural gas utilities listed in Value Line, including two companies that NSTAR Gas excluded from its proxy group (Exhs. AG-JRW at 7, 29 and 28-29; JRW-2). The median operating revenues for the Attorney General's proxy group companies is $1,952,000,000 and the median net plant for the group is $4,599,000,000 (Exhs. AG-JRW at 29; JRW-2, at 1). The group receives an average of 70 percent of their revenues from regulated gas operations, has an average issuer credit rating of A-/BBB+ from S&P, has an average issuer credit rating from Moody's Investor Service ("Moody's") of Baa1, a current common equity ratio of 45.8 percent, and an average earned return on common equity of 8.70 percent (Exhs. AG-JRW at 29; JRW-2, at 1).

3. Positions of the Parties

a. Attorney General

The Attorney General used credit ratings as measures of investment risk to compare NSTAR Gas to the proxy groups (Attorney General Brief at 77, citing Exh. JRW-2). According to the Attorney General, the S&P issuer credit rating for NSTAR Gas is A- and Eversource's S&P rating was A+ before it was downgraded by two notches on July 25, 2019 as a result of Eversource's decision to pursue growth through riskier offshore wind investments (Attorney General Brief at 77, citing Exh. JRW-2, Att.). Further, the Attorney General notes that S&P stated that NSTAR Gas would be one rating step higher, if not for its parent company's unregulated business investments incursions, and that the average S&P issuer credit rating for the Company's proxy group is A-/BBB+ (Attorney General Brief at 77, citing Exh. JRW-2, Att.). The Attorney General argues that, contrary to the Company's assertions, the Company's revenue decoupling and PBR mechanisms decrease the Company's risk relative to other gas companies even despite the PBRM's five-year stay-out provision (Attorney General Brief at 97-98).

The Attorney General contends that, even with the rating downgrade, Eversource's S&P rating is one-half notch above the average of the gas proxy group (Attorney General Brief at 78). The Attorney General also asserts that the Company's A- S&P issuer credit ratings is above the average of the Company's proxy group (Attorney General Brief at 71). Thus, taking into consideration Eversource and the Company's credit ratings, she concludes that NSTAR Gas is slightly less risky as compared to the proxy groups (Attorney General Brief at 78).

b. Company

The Company argues that its proxy group is consistent with Department precedent because the seven companies in the group have common stock that is publicly traded and that the companies are generally of comparable investment risk to NSTAR Gas (Company Brief at 355-357, citing D.P.U. 17-170, at 272; D.P.U. 14-150, at 329; D.P.U. 12-25, at 395-397, 402). The Company contends that revenue decoupling and PBR mechanisms do not make NSTAR Gas less risky vis-a-vis the proxy group because nearly all the operating companies in the proxy group have revenue decoupling mechanisms in place (Company Brief at 357, citing Exh. ES-RBH-Rebuttal-1, at 24). In addition, the Company states that although the companies in the proxy group are not identical to the Company in every aspect, the Department has recognized that it is neither necessary nor possible to find a group that matches the utility seeking relief in every detail (Company Brief at 357, citing D.P.U. 09-30, at 307).

4. Analysis and Findings

The use of a proxy group of companies is standard practice in setting an ROE that is comparable to returns on investments of similar risk. D.P.U. 08-35, at 176-177; D.T.E. 99-118, at 80-82; D.P.U. 92-78, at 109-110; D.P.U. 1300, at 97. The use of a proxy group is especially relevant for evaluation of a cost of equity analysis when a distribution company does not have common stock that is publicly traded. D.P.U. 08-35, at 176-177; D.T.E. 99-118, at 80-82; 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 the Company and the Attorney General, we recognize that it is neither necessary nor possible to find a group in which the companies match NSTAR Gas in every detail. D.T.E. 99-118, at 80; D.P.U. 87-59, at 68; Boston Gas Company, D.P.U. 1100, at 135-136 (1982). 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 NSTAR Gas versus the proxy group. D.T.E. 99-118, at 80; D.P.U. 87-59, at 68; D.P.U. 1100, at 135-136.

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. D.P.U. 12-25, at 402; D.P.U. 09-30, at 307. Therefore, the Department will accept the use of both proxy groups to assist the Department in determining the Company's fair and reasonable cost of equity. 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 stated that the cost of equity must be estimated based on market data and financial models applied to a group of proxy companies, and it explained that the choice of models, selection of proxy companies, and interpretation of model results should consider quantitative and qualitative data and information not necessarily included in the models themselves (Exh. ES-RBH-1, at 10). Specifically, the Company supported its 10.45-percent ROE proposal with four models: (1) the constant growth discounted cash flow ("DCF") model; (2) the capital asset pricing model ("CAPM"); (3) the empirical CAPM model ("ECAPM"); and (4) the bond yield plus risk premium method ("risk premium model") (Exh. ES-RBH-1, at 3).[171]

Further, the Company analyzed the implications of several other factors, including prospective safety and compliance regulations, the risk of the PBR Plan's stay-out period, the risk implications of pipeline capacity constraints in New England, the effect of the Company's cash flow relative to its capital expenditures, flotation costs,[172] and evolving capital market and business conditions, including increased volatility (Exh. ES-RBH-1, at 3-4, 29-51). NSTAR Gas determined that an ROE in the range of 10.00 percent to 10.75 percent represents the range of returns required by equity investors under current and expected market conditions and concluded that a 10.45-percent ROE is a reasonable estimate of the Company's cost of equity (Exhs. ES-RBH-1, at 2, 54; ES-RBH-Rebuttal-1, at 120).

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171 The Company presented an expected earnings analysis as a corroborating method (Exh. ES-RBH-1, at 18).

172 Flotation costs are the costs that are incurred by a company when issuing new securities, i.e., issuance costs.

2. Attorney General's Proposal

The Attorney General provides that the cost of equity cannot be determined precisely and must be estimated from market data and informed judgment and that the stockholder's revenue requirement should be commensurate with the return requirement on investments in companies with comparable risks (Exh. AG-JRW at 46). The Attorney General applied the financial data from her proxy group to DCF and CAPM cost of equity models (Exhs. AG-JRW at 4, 116; AG-JRW-Surrebuttal at 3). The Attorney General's DCF analysis produced an ROE of 9.10 percent, and her CAPM analysis resulted in an ROE of 6.60 percent (Exhs. AG-JRW-Surrebuttal at 34, 37; AG-JRW-Surrebuttal-2; AG-JRW-Surrebuttal-3). The Attorney General assigned greater weight to the DCF model because it provides the best measure of the cost of equity given the investment valuation process and relative stability of the utility business, and she concluded with an ROE of 9.0 percent using her proposed capital structure (Exhs. AG-JRW, at 47, 74, 116; AG-JRW-Surrebuttal, at 38, Table 6).[173] Alternatively, if the Department approves the Company's proposed capital structure, the Attorney General recommends that the Department recognize that the higher common equity ratio renders NSTAR Gas less risky and approve an 8.75-percent ROE (Exh. AG-JRW at 5-6). Regarding the other factors considered by the Company, the Attorney General states that consideration of flotation costs is inappropriate for

[173] The Attorney General used updated financial data and model results to revise her ROE proposal during the proceeding; her initial proposal was an 8.5-percent ROE supported by an 8.55-percent ROE based on the DCF and a 7.0-percent ROE based on the CAPM (Exhs. AG-JRW at 5, 60, 73; JRW-7; JRW-8).

NSTAR Gas; the potential safety and compliance regulations, gas capacity constraints, and cash flow to capital expenditures ratio do not suggest that the Company is a higher risk than the proxy group companies; and the Company's proposed PBRM decreases the Company's risk relative to other gas companies (Exh. AG-JRW at 113-114).

### 3. DOD-FEA's Proposal

To estimate NSTAR Gas's cost of equity, DOD-FEA applied the following financial models to the Company's proposed capital structure and proxy group: (1) a DCF model using the consensus of analysts' growth rate projections; (2) a DCF model using sustainable growth rate estimates; (3) a multi-stage DCF model; (4) a risk premium model; and (5) a CAPM (Exh. DOD-CCW-1, at 19-21). DOD-FEA recommends an ROE of 9.30 percent, which is the midpoint of DOD-FEA's DCF, CAPM, and risk premium modeling results for the Company's proxy group (Exhs. DOD-CCW-1, at 54; DOD-CCW-Surrebuttal-1, at 13). Additionally, DOD-FEA stated that the additional factors relied upon by NSTAR Gas are taken into consideration in the Company's S&P credit rating, which is identical to the proxy group (Exh. DOD-CCW-1, at 78). Therefore, DOD-FEA stated that these additional factors do not support a conclusion that the Company is riskier than the proxy group (i.e., increased regulatory oversight, capacity constraints, and cash flow to capital expenditures ratio) (Exh. DOD-CCW-1, at 78). Further, DOD-FEA provided that the PBR Plan stay-out term does not warrant a premium built into the ROE (Exh. DOD-CCW-1, at 78-79).

### 4. Capital Market Conditions

#### a. Introduction

Market conditions, as evaluated both quantitatively and qualitatively, play an important role in defining the parties' respective positions on cost of equity (Exhs. ES-RBH-1, at 39; AG-JRW, at 4-7; DOD-CCW-1, at 39-40). The Company and intervenors offer conflicting interpretations of market conditions and the corresponding risk profiles for NSTAR Gas (Exhs. ES-RBH-1, at 39-51; ES-RBH-Rebuttal-1 at 2-19; AG-JRW, at 12-29; AG-JRW-Surrebuttal at 21, 30-32; DOD-CCW-1, at 54-55; DOD-CCW-Surrebuttal-1 at 2-4). The Companies and intervenors draw on data selected from the market place to implement their models in an effort to accurately assess current market conditions and to forecast the market's likely future course with respect to and in support of the most appropriate cost of equity for NSTAR Gas (Exhs. ES-RBH-1; ES-RBH-Rebuttal-1; AG-JRW; AG-JRW-Surrebuttal; DOD-CCW-1; DOD-CCW-Surrebuttal-1).

By way of illustration, the Company and intervenors vigorously dispute the implications of recently observed trends in authorized utility ROEs regionally and nationally (Exhs. ES-RBH-1, at 44-45; ES-RBH-Rebuttal-1, at 33-36; AG-JRW at 26-28; AG-JRW-Surrebuttal at 4-5; DOD-CCW-1, at 4-10; DOD-CCW-Surrebuttal-1, at 4-6). In support of her position, the Attorney General notes that recent rate case records show that authorized electric and gas utility ROEs across the U.S. have trended downward (Exh. AG-JRW at 25-26; AG-JRW-Surrebuttal at 5-6). Conversely, the Company observes that authorized ROEs for electric and gas utilities have not moved in step with the low interest rate environment, noting that despite the decline in yields in 2015 and 2016, and again in late 2018 through 2019, regulatory commissions have not been inclined to reduce authorized returns (Exh. ES-RBH-1, at 44-45; ES-RBH-Rebuttal-1, at 33-34).

b. Positions of the Parties

i. 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 its higher proposed ROE (Attorney General Brief at 93-97). 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 U.S.; (2) NSTAR Gas's risk profile conforms to this low-risk industry category as measured by its proxy group's S&P issuer credit rating of A-; (3) the gas distribution industry is among the lowest risk industries in the U.S. as measured by beta,[174] and (4) authorized ROEs for gas distribution companies have decreased in recent years (Attorney General Brief at 99).

The Attorney General asserts that her recommended ROE of 9.0 percent satisfies the requirements of Federal Power Commission v. Hope Natural Gas Company, 320 U.S. 591 (1944) ("Hope") and Bluefield Waterworks and Improvement Company v. Public Service Commission of West Virginia, 262 U.S. 679 (1923) ("Bluefield") (Attorney General Brief at 99).

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174 The beta of a stock measures the stock's volatility relative to that of the rest of the market. Betas for utility stocks are usually less than 1.0, which indicates a lower variability and hence lower risk to the market. D.P.U. 17-70, at 293 n.156 (2018).

ii. DOD-FEA

DOD-FEA argues that its proposed ROE of 9.3 percent will provide NSTAR Gas with an opportunity to produce a debt to earnings before interest, taxes, depreciation, and amortization ("EBITDA") metric of 4.1 x which is within S&P's "significant" guideline range of 3.5 x to 4.5 x (DOD-FEA Brief a 13). According to DOD-FEA, this debt-to-EBITDA metric would support NSTAR Gas's credit rating based on S&P reported business risk profile score of "excellent" assigned to the Company (DOD-FEA Brief at 13).

DOD-FEA notes that NSTAR Gas's retail operations' funds from operations ("FFO") to total debt ratio at a 9.3-percent equity return would be 18 percent, which is within S&P's "significant" metric guideline range of 13 percent to 23 percent (DOD-FEA Brief at 13). Further, DOD-FEA argues that an FFO-to-total debt ratio of 18 percent is consistent with an A- rating based on NSTAR Gas's "excellent" business risk score from S&P (DOD-FEA Brief at 13, citing Exh. DOD-CCW-1, at 58). Finally, based on these credit metrics, DOD-FEA concludes that its ROE recommendation of 9.3 percent represents fair compensation that will provide NSTAR Gas an opportunity to produce credit metrics that will support its A-bond rating (DOD-FEA Brief at 13).

iii. Company

NSTAR Gas argues that its proposed ROE of 10.45 percent reflects current capital market conditions and is the result of a number of widely accepted common equity cost models (Company Brief at 381). NSTAR Gas contends that the Department will need to follow the established legal principle of providing a return commensurate with the returns for similar enterprises having corresponding risks (Company Brief at 353, citing Attorney

General v. Department of Public Utilities, 392 Mass. 266 (1984), quoting Hope at 603). In this regard, the Company notes that its proposed ROE of 10.45 percent is based, in part, on a proxy group of seven gas distribution companies that have comparable risk characteristics to NSTAR Gas (Company Brief at 355, citing Exh. ES-RBH-1, at 17). In addition, the Company argues that there is no evidence that the Company will be less risky because of the PBRM, and, therefore, any reduction in the ROE because the Company has a PBRM would be inappropriate (Company Brief at 374).

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 353, citing Boston Edison v. Department of Public Utilities, 375 Mass. 305, 315 (1978), citing Hope at 603). 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 for it to maintain safe and reliable service (Company Brief at 354). The Company asserts that the Attorney General's recommended ROE of 8.75 percent or, in the alternative, 9.0 percent, will make it very difficult for the Company to attract capital at a reasonable cost (Company Brief at 377; Company Reply Brief at 69). 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[175] (Company Brief at 377-378).

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175 Regarding recent allowed returns, the Company argues that in 2017, the Department approved an ROE of 10.0 percent for Eversource's electric distribution companies (Company Brief at 378, citing D.P.U. 17-05, at 713). In addition, the Company

The Company argues that the recent fall in interest rates cannot be seen as indicating a decrease in the cost of equity but rather as the result of safety-seeking behavior on the part of investors related to an extraordinarily volatile market caused by the COVID-19 pandemic (Company Brief at 376, citing Exh. ES-RBH-Rebuttal-1, at 22). The Company states that despite a recent decline in interest rates, the Attorney General's witness still increased his recommended ROE by 50 basis points (Company Brief at 376, citing Attorney General Brief at 67).

Finally, the Company argues that its proposed ROE of 10.45 percent reflects current capital market conditions, including the pandemic, and is the result of applying a number of widely accepted common equity models (Company Brief at 381; Company Reply Brief at 71).

c. Analysis and Findings

The Company and intervenors present observations in the instant case that paint two distinctly different pictures of capital market conditions and the relative risks posed to NSTAR Gas in support of their respective ROE recommendations (Exhs. ES-RBH-1, at 39-51; ES-RBH-Rebuttal-1 at 2-19; AG-JRW, at 12-29; AG-JRW-Surrebuttal at 21, 30-32; DOD-CCW-1, at 54-55; DOD-CCW-Surrebuttal-1 at 2-4). Regarding the market conditions debated among the Company and intervenors, there is an abundance of record evidence indicating the slow pace of economic recovery since the 2008 economic crisis. GDP growth,

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notes that earlier this year, before the pandemic, the Department authorized an ROE of 9.70 percent for Unitil's gas operations (Company Brief at 378, citing D.P.U. 19-131, at 9).

inflation, and interest rates all remain at historical lows (Exhs. ES-RBH-1, at 43-44; ES-RBH-Rebuttal-1, at 56; AG-JRW-Surrebuttal at 5, 17-18, 30-31, 35). Projecting future market trends, whether interest rates, dividends and earnings growth, betas, or GDP growth is difficult through surveys and modeling alike, and both the Company and intervenors use caution in reaching their conclusions (Exhs. ES-RBH-Rebuttal-1, at 26, 54-56; AG-JRW at 21, 23, 51-52, 62; DOD-CCW-Surrebuttal-1, at 6).

The parties draw from a host of data sources and methodologies in their competing interpretations and conclusions (Exhs. ES-RBH-Rebuttal-1, at 20-109; AG-JRW Surrebuttal at 8-32; DOD-CCW-Surrebuttal-1, at 2-14). The Company agrees with the Attorney General that since mid-February capital markets have been historically unstable, and also concur with the Attorney General's observation that when market prices diverge from some measure of intrinsic value, the disequilibrium affects the reliability of certain model results (Exh. ES-RBH-Rebuttal-1, at 12). However, even with the difficulty of assigning precise basis point increments to the increased market risk, the Company infers that there has been an upward directional change in the cost of equity (Exh. ES-RBH-Rebuttal-1, at 12-13). The interveners, based on the same developments and current market risk, consider that the overall impact on capital costs and cost of equity is of a more mixed nature (Exh. AG-JRW-Surrebuttal at 32). We will consider current capital market conditions as well as projections in evaluating the analysis models used by the parties.

Regarding trends in authorized ROE nationally and regionally, under the principles of Hope and Bluefield, regulated utilities are entitled to earn a return on capital investments consistent with the returns for business of similar risk levels. The return for regulated utilities must be adequate to provide access to capital and to support credit quality, and they must result in just and reasonable rate for consumers. While ROEs granted in other jurisdictions may be indicative of general overall trends, without knowing what quantitative and qualitative factors were considered in these other regulatory agencies, the Department is unable to conclude that these ROEs are appropriate for NSTAR Gas under the Hope and Bluefield principles. Therefore, the Department places limited weight on overall ROE trends in setting the allowed ROE for the Company.

5. Discounted Cash Flow

a. Company's Proposal

A noted above, NSTAR Gas used a constant growth DCF model as one approach to estimate an appropriate ROE. 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. ES-RBH-1, at 56). The Company calculated the dividend yield component based on the current annualized dividends of its proxy group (Exh. ES-RBH-1, at 57). For the expected growth rate, the Company used a consensus of the Zacks Investment Research, Inc. ("Zacks"), Thomson Reuters First Call ("First Call"), and Value Line surveys to estimate a long-term earnings growth rate (Exhs. ES-RBH-1, at 60; ES-RBH-Rebuttal-2).[176] During the

[176] Zacks, First Call, and Value Line provide a wide range of investment research and industry analysis services.

proceedings, NSTAR Gas updated its data to produce a cost of equity range of 7.76 percent to 13.52 percent (Exh. ES-RBH-Rebuttal-2).[177]

b. Attorney General's Proposal

To determine the cost of capital using her DCF model, the Attorney General summed the estimated dividend yield and growth rates of her proxy group (Exh. AG-JRW at 52-54).[178] The Attorney General calculated the 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. ("Yahoo") (Exhs. AG-JRW at 52; JRW-7, at 2; JRW-Surrebuttal-2, at 2). The mean and median dividend yields for the Attorney General's proxy group using this method range from 2.9 percent to 3.2 percent (Exhs. AG-JRW at 52; JRW-7, at 2; JRW-Surrebuttal-2, at 2). Within this range, the Attorney General chose 3.0 percent as the dividend yield for her gas proxy group (Exhs. AG-JRW-Surrebuttal at 33; JRW-Surrebuttal-2, at 1-2).

The dividend yield is obtained by dividing the annualized expected dividend in the coming quarter by the current stock price (Exh. AG-JRW at 52). To annualize the expected dividend, the Attorney General multiplied the expected dividend for the coming quarter by

177 NSTAR Gas's initial DCF model results produced a cost of equity range of 9.98 percent to 11.67 percent (Exh. ES-RBH-1, at 61).

178 The Attorney General updated her constant DCF and CAPM results with adjusted data from March 20, 2020, and she presented the new results in a May 8, 2020 filing (Exhs. AG-JRW-Surrebuttal, at 32-37; AG-JRW-Surrebuttal-2; AG-JRW-Surrebuttal-3).

four and multiplied the result by one-half of the expected growth rate (Exhs. AG-JRW at 53; JRW-Surrebuttal-2, at 1).

In developing the expected growth rate, the Attorney General relied on the historic and projected growth rates of earnings per share ("EPS"), dividends per share, and book value per share provided by Value Line and the EPS growth forecasts of Wall Street analysts provided by Yahoo and Zacks (Exh. AG-JRW at 53-54). Although the Attorney General assumes that EPS 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 EPS as a proxy (i.e., an upward bias among Wall Street analysts) (Exh. AG-JRW at 55-56). The DCF growth rate for the proxy group used in the Attorney General's analysis is 6.0 percent (Exhs. AG-JRW-Surrebuttal at 34; JRW-Surrebuttal-2, 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, at 60; JRW-7, at 1, JRW-Surrebuttal-2, at 1). The DCF analysis performed by the Attorney General yields a cost of equity of 9.10 percent (Exhs. AG-JRW at 60; JRW-7, at 1; AG-JRW-Surrebuttal at 34; JRW-Surrebuttal-2, at 1).

c. DOD-FEA's Proposal

DOD-FEA used two constant growth DCF models and one multi-stage DCF model, which, produced median costs of equity ranging from 7.58 percent to 10.88 percent (Exhs. DOD-CCW-1, at 19-20; DOD-CCW-Surrebuttal-1, at 8; DOD-CCW-Surrebuttal-2;

through DOD-CCW-Surrebuttal-6).[179] For its securities inputs, DOD-FEA relied on the average weekly high and low stock prices of the utilities in the Company's proxy group over a 13-week period ending May 1, 2020 (Exhs. DOD-CCW-Surrebuttal-1, at 8; DOD-CCW-Surrebuttal-2; DOD-CCW-Surrebuttal-4, at 2; DOD-CCW-Surrebuttal-5; DOD-CCW-Surrebuttal-6). DOD-FEA also collected the most recent quarterly dividends paid by each of these companies as reported by Value Line on February 28, 2020, resulting in an average adjusted dividend yield of 3.30 percent (Exhs. DOD-CCW-1, at 25; DOD-CCW-Surrebuttal-2). DOD-FEA then used consensus professional security analysts' earnings growth estimates from Zacks, S&P Global Market Intelligence, and Yahoo to produce an average growth rate of 6.30 percent for the proxy group (Exhs. DOD-CCW-1, at 26-27; DOD-CCW-5; DOD-CCW-Surrebuttal-1). The average and median constant growth DCF cost of equity returns for the Company's proxy group for the 13-week analysis are 9.30 percent and 9.60 percent, respectively (Exhs. DOD-CCW-1, at 26-27; DOD-CCW-6; DOD-CCW-Surrebuttal-2).

In its second constant growth DCF calculation, DOD-FEA uses an average, sustainable long-term growth rate of 7.08 percent derived from dividend payout ratios and earnings retention ratios as well as from market-to-book ratios and Value Line projections of earnings, dividends, earned returns on book equity, and stock issuances

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179 DOD-FEA's initial DCF model results produced median costs of equity ranging from 7.37 percent to 11.38 percent (Exhs. DOD-CCW-1, at 37; DOD-CCW-6; DOD-CCW-9; DOD-CCW-11).

(Exhs. DOD-CCW-1, at 28-29; DOD-CCW-Surrebuttal-4). DOD-FEA also collected the most recent quarterly dividends paid by each company in the Company's proxy group as reported by Value Line on February 28, 2020, resulting in an average adjusted dividend yield of 3.32 percent (Exhs. DOD-CCW-1, at 28-29; DOD-CCW-Surrebuttal-5, at 1). This sustainable constant growth DCF analysis, over a 13-week period average stock price, produced average and median DCF costs of equity of 10.40 percent and 10.88 percent, respectively, for the Company's proxy group (Exhs. DOD-CCW-1, at 28-29; DOD-CCW-Surrebuttal-5).

DOD-FEA's multi-stage growth DCF analysis employs an average of (1) the 6.30-percent consensus analysts' growth projections for the first stage, short-term growth period; (2) a growth rate range of 4.38 percent to 5.92 percent for the second stage transition period;[180] and (3) a 4.0-percent consensus analysts' projection of long-term nominal gross domestic product ("GDP")[181] growth for the third stage (Exhs. DOD-CCW-1, at 30-31, 35; DOD-CCW-Surrebuttal-6).[182] This multi-stage model produces an average and median DCF

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180 DOD-FEA states that growth rates for the second stage, transition period were reduced or increased by an equal factor reflecting the difference between the analysts' growth rates and the long-term, sustainable growth rates, resulting in growth rates of 5.92, 5.53, 5.15, 4.77, and 4.48 percent in years six through ten, respectively (Exhs. DOD-CCW-11; DOD-CCW-Surrebuttal-6).

181 Generally, GDP is a monetary measure of the market value of all the final goods and services produced in a specific time period, often presented annually.

182 For the third stage analysis, DOD-FEA relied on the consensus economists' projected ten-year GDP growth rates as published by Blue Chip Economic Indicators (Exhs. DOD-CCW-1, at 34; DOD-CCW-11; DOD-CCW-Surrebuttal-6).

cost of equity of 7.78 percent and 7.58 percent, respectively (Exhs. DOD-CCW-1, at 37; DOD-CCW-Surrebuttal-6).

d. Positions of the Parties

i. Attorney General

The Attorney General contends that the Company's DCF analyses suffer from two errors: (1) the exclusive reliance on Wall Street analysts' and Value Line's overly optimistic and upwardly biased forecasts of growth on EPS and (2) the combination of EPS for the proxy companies computed from a three-year base period with three-to-five-year projected growth rates from First Call and Zack's (Attorney General Brief at 70, 80). The Attorney General asserts that the record contains ample evidence to demonstrate that the long-term earnings growth rates of Wall Street analysts and Value Line are overly optimistic and can lead to an upward bias in cost of equity estimates of almost three percentage points (Attorney General Brief at 81, citing Exh. AG-JRW at 81-84; Attorney General Reply Brief at 30-31). Additionally, the Attorney General avers that the Company's Value Line growth rates are inflated because six of NSTAR Gas's seven proxy companies experienced abnormally high or low earnings during the three-year base period (Attorney General Brief at 81-82, citing Exh. AG-JRW at 81-84). Accordingly, the Attorney General argues that the Department should reject the Company's flawed DCF results (Attorney General Brief at 80).

ii. DOD-FEA

DOD-FEA avers that a 9.0-percent ROE is reasonable based on the results of its DCF models (DOD-FEA Brief at 4-6). DOD FEA contends that the Company has used excessive and unsustainable growth rate assumptions when applying its DCF analysis (DOD-FEA Brief at 14). Specifically, DOD-FEA asserts that the Company's low, mean, and high DCF results are based on average growth rates of 4.84 percent, 7.24 percent, and 11.22 percent respectively (DOD-FEA Brief at 14). According to DOD-FEA, each of these growth rate estimates are above the projected growth of the U.S. economy of 4.2 percent (DOD-FEA Brief at 14). DOD-FEA argues that no company or industry can grow at a faster rate than the economy in perpetuity, which is the assumed timeline in the constant growth DCF model (DOD-FEA Brief at 14). Further, DOD-FEA argues that the Company's DCF result should be rejected in its entirety because the Company's proposed high growth rate of 11.22 percent is nearly 2.7 times higher than the projected growth rate of 4.2 percent for the U.S. economy, which DOD-FEA considers an improbable and unreasonable expectation (DOD-FEA Brief at 14).

DOD-FEA argues that, in conducting its DCF analysis, the Company acted in an opportunistic manner by incorporating a sustainable or retention growth rate element that the Company's expert witness had rejected in previous cases (DOD-FEA Brief at 14, citing Tr. 5, at 622; DOD-FEA Reply Brief at 3). Further, DOD-FEA maintains that the Company did not provide any evidence to support its claim that retention growth rates are appropriate for gas utilities but not electric utilities because of differences between the industries (DOD-FEA Reply Brief at 3). DOD-FEA claims that the results of NSTAR Gas's DCF analysis would have been substantially lower if it had not relied on the retention growth method (DOD-FEA Brief at 14). For these reasons, DOD-FEA argues that the Company's DCF analyses are unreliable (DOD-FEA Brief at 14).

iii. Company

NSTAR Gas asserts that its calculation of the dividend yield ensured that the models' results were not skewed by anomalous events (Company Brief at 357, citing Exh. ES-RBH-1, at 56). In addition, the Company maintains that analysts' forecasts of growth are superior to other measures of growth in predicting stock prices (Company Brief at 357, citing Exh. ES-RBH-1, at 57). NSTAR Gas avers that the Attorney General's criticisms of the Company's DCF analyses are without merit and that the Attorney General's DCF calculation must be rejected for its flaws (Company Brief at 368-370).

Regarding the Attorney General's view that the Company places undue reliance on EPS forecasts of financial market analysts when applying its DCF analysis, the Company argues that it is the appropriate measure of growth for the DCF model (Company Brief at 368). NSTAR Gas contends that the Attorney General's claim of overly-optimistic growth rate estimates by analysts lacks merit, because adoption of the 2003 Global Research Analysts Settlement ("2003 Settlement") [183] helped to neutralize bias among financial analysts (Company Brief at 369, citing Exh. ES-RBH-Rebuttal-1, at 43). Further, according to the Company, many of the articles that the Attorney General's witness cites in support of his position are based on research that predate the 2003 Settlement (Company Brief at 369). Moreover, the Company asserts that the Department has noted a lack of pronounced bias in

183 The 2003 Settlement resolved an investigation by the U.S. Securities and Exchange Commission ("SEC") and the New York Attorney General's Office of a number of investment banks related to concerns about conflicts of interest that might influence the independence of investment research provided by equity analysts (Exh. ES-RBH-Rebuttal at 39, n.107).

EPS forecasts and states that the Attorney General has provided no direct evidence to demonstrate bias (Company Brief at 369, citing D.P.U. 13-75, at 302). Ultimately, the Company argues, that it is irrelevant whether the EPS forecasts are biased because it is actually the EPS growth rate expectations of investors that drive stock prices and that these expectations are influenced by analysts' forecasts (Company Brief at 369-370, citing Exh. ES-RBH-Rebuttal-1, at 41).

The Company also asserts that the Attorney General's DCF cost of equity 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 368, citing Exh. ES-RBH-Rebuttal-1, at 42-43). The Company maintains that the Department has placed "more weight on EPS growth rates" because of the "evidence that EPS growth rates provide a more statistically reliable measure of growth than dividend-per-share or book-value-per share (Company Brief at 368, citing D.P.U. 18-150, at 472).

e. Analysis and Findings

In developing their proposed ROEs, the Company and intervenors use a form of the DCF model that assumes an infinite investment horizon and a constant growth rate (Exhs. ES-RBH-1, at 3, ES-RBH-3; AG-JRW at 4; JRW-6; DOD-CCW-1, at 23-24; DOD-CCW-6; DOD-CCW-9). In the constant growth DCF model, the cost of equity is the sum of the dividend yield and the growth rate (Exhs. ES-RBH-3; JRW-7, at 1; DOD-CCW-1, at 24). This model makes a number of strict assumptions, including that dividends, book value, and earnings all grow at the same constant rate in perpetuity, that the dividend payout ratio and cost of equity and price-to-earnings ratio remain constant, and that the estimated cost of equity will remain constant in perpetuity (Exhs. ES-RBH-1, at 56; AG-JRW at 50). These assumptions affect the estimates of the cost of equity. D.P.U. 15-155, at 364; D.P.U. 09-39, at 387. In addition, DOD-FEA has included a multi-stage DCF model that diminishes the assumption that the growth rate of dividends, book value, and earnings remains constant in perpetuity (Exh. DOD-CCW-11).

Because regulatory commissions establish a level of authorized earnings for a utility that, in turn, implicitly influences dividends per share, the 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. Specifically, 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 results of both the Companies' and the intervenors' DCF models.

As stated above, the Company, Attorney General, and DOD-FEA use different growth rates in their respective DCF analyses (Exhs. ES-RBH-Rebuttal-2; ES-RBH-Rebuttal-3; JRW-Surrebuttal-2; DOD-CCW-Surrebuttal-1; DOD-CCW-Surrebuttal-2 through DOD-CCW-Surrebuttal-5). Determining the appropriate long-term growth expectations of investors in a DCF analysis is often difficult and controversial. D.P.U. 15-155, at 365. The Company relies on the forecasted EPS growth rates of financial market analysts, based on the assumption that investors form their investment decisions based on expectations of growth in earnings and not dividends (Exhs. ES-RBH-1, at 60;

ES-RBH-Rebuttal-1, at 40, 42-43; ES-RBH-Rebuttal-2). The Attorney General emphasizes dividend growth over earnings growth because of the alleged upward bias of forecasts by financial analysts (Exhs. AG-JRW at 83-84; AG-JRW-7; AG-JRW-Surrebuttal-2). On the other hand, DOD-FEA base its growth rate on a historical and forward-looking growth analysis using EPS, dividends-per-share, book-value-per-share, and retention growth rates (Exhs. DOD-CCW-7; DOD-CCW-8; DOD-CCW-9; DOD-CCW-Surrebuttal-3; DOD-CCW-Surrebuttal-4; DOD-CCW-Surrebuttal-5). In this case, however, there is evidence that EPS growth rates provide a more statistically reliable measure of growth than dividends-per-share or book-value-per-share, in light of utility price-earnings ratios being greater than historical averages in recent years (Exhs. ES-RBH-Rebuttal-1, at 44; ES-RBH-Rebuttal-12). In view of this evidence, the Department places more weight on EPS growth rates.

Notwithstanding the weight we accord to EPS growth rates, the Department recognizes that investors acknowledge the existence of upward biases in EPS forecasts and take these biases into consideration in evaluating the results of a DCF analysis. D.P.U. 15-155, at 366; D.P.U. 13-75, at 302. Additionally, the Department recognizes that arithmetically, in the constant growth DCF model, an overstated EPS growth rate that is incorporated in the stock price puts downward pressure on the dividend yield. Furthermore, the Department notes that the growth rate of the DCF model is that of dividends and that an underlying assumption of the DCF model is that dividends, earnings, and book value all grow at the same rate (Exhs. AG-JRW at 50; ES-RBH-1, at 19, n.18).

The Company argues that the Attorney General has provided no direct evidence that analysts' EPS forecasts are upwardly biased and that the 2003 Settlement has helped to neutralize the bias (Company Brief at 369; Company Reply Brief at 66). The Department previously questioned whether the 2003 Settlement addressed causes of upward bias in EPS growth rates forecasts that can lead to overly-optimistic EPS forecasts by financial market analysts. Massachusetts Electric Company/Nantucket Electric Company, D.P.U. 18-150, at 473 (2019). Upon further review of the terms of the 2003 Settlement, including enforcement and structural reforms, we find that there is a strong likelihood that the 2003 Settlement has mitigated systematic bias in overly optimistic stock recommendations. Relevant terms of the 2003 Settlement include overriding injunction against violations of specified statutes and rules, substantial disgorgement and civil penalties (approximately $1.5 billion), and structural reforms proscribing explicit practices including the tying of analysts' compensation to investment banking outcomes, required physical and organizational separation of research and investment banking divisions, publication of additional information on ratings systems used, fund and publish research from independent analysts, and retention of an independent monitor to provide reasonable assurance of compliance (SEC Fact Sheet on Global Analyst Research Settlements).[184] On this basis, the Department finds that analyst growth rate forecasts are not still subject to overly-optimistic projections tending to overstate the required ROE.

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[184] Available at https://www.sec.gov/news/speech/factsheet.htm

Regarding DOD-FEA's criticism of the retention growth rate approach, the Department has previously found that the retention growth rate approach is useful and appropriate within the context of a DCF analysis. AT&T Communications of New England, D.P.U. 85-137, at 106 (1985); Western Massachusetts Electric Company, D.P.U. 84-25, at 163 (1984). The principal components of this method are the dividend retention ratio and the return on equity (Tr. 5, at 623). For the retention growth rate approach to work, it is assumed that both the dividend retention ratio and the return on equity remain constant over the long term (Tr. 5, at 623). The Company has presented credible evidence that in the case of electric companies, these factors are not expected to remain constant over the long term (Company Brief at 379-380, citing Tr. 5, at 623-624). On this basis, the Department finds that the Company's rationale for limiting this approach to gas utilities reasonable.

Based on the foregoing, the Department recognizes the limitations of the Company's, the Attorney General's, and DOD-FEA's DCF models. For these reasons, the Department does not rely on any one of these models in isolation. We find, however, that taking their limitations into account these DCF models provide credible evidence for a reasonable range of ROE from 8.5 percent to 11.5 percent.

6. Capital Asset Pricing Model

a. Company's Proposal

The Company used the CAPM to calculate the cost of equity for its proxy group (Exhs. ES-RBH-1, at 3, 6, 18, 22, 65: ES-RBH-6; ES-RBH-7). The application of the Company's CAPM resulted in eight individual costs of equity calculations, ranging from 9.02 percent to 13.91 percent (Exhs. ES-RBH-1, at 6, 24; NG-RBH-Rebuttal-1, at 10;

ES-RBH-Rebuttal-6).[185] NSTAR Gas considered these results when determining its proposed ROE (Exhs. ES-RBH-1, at 3; ES-RBH-Rebuttal-1, at 10; ES-RBH-Rebuttal-6).

The CAPM is a market-based investment model based on capital markets theory and modern portfolio theory. D.P.U. 15-155, at 366. In the CAPM, the required ROE is equal to the expected risk-free rate of return plus a premium for the implicit systematic risk of the security (Exh. ES-RBH-1, at 61). The CAPM model includes three components in calculating the cost of equity: (1) an expected risk-free rate of return; (2) the market risk premium; and (3) the beta coefficient, a measure of systematic risk (Exhs. ES-RBH-1, at 61; ES-RBH-7).

The Company used the current 30-year U.S. Treasury bond yield of 1.37 percent and forecasted 30-year Treasury bond yields of 1.75 percent to determine the current and near-term risk-free rates (Exh. ES-RBH-Rebuttal-6). The Company then developed ex-ante or expected market risk premiums based on data from both Bloomberg and Value Line by calculating its respective estimated market-required returns less the U.S. Treasury bond yield (Exhs. ES-RBH-1, at 64; NG-RBH-7; ES-RBH-Rebuttal-6). The Company determined these market-required returns by applying its constant growth DCF model to the companies listed in S&P 500 Index ("S&P 500"),[186] producing a market-required return of 12.93 percent

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185 In its rebuttal testimony, the Company updated the results of the CAPM (Exhs. ES-RBH-Rebuttal-1, at 1; ES-RBH-Rebuttal-6).

186 The S&P 500 is an American stock market index based on the market capitalizations of the 500 largest U.S. companies having common stock listed on the New York Stock Exchange or the NASDAQ Stock Market.

based on data from Bloomberg, and a market-required return of 14.82 percent based on data from Value Line (Exh. ES-RBH-Rebuttal-4). Based on this analysis, the Company derived a market risk premium of 11.56 percent based on data from Bloomberg, and a market risk premium of 13.45 percent based on data from Value Line (Exh. ES-RBH-Rebuttal-4).

The Company obtained beta coefficients for its proxy group from Bloomberg (0.904) and Value Line (0.629) (Exhs. ES-RBH-1, at 64; ES-RBH-Rebuttal-5). The Company multiplied these beta coefficients by the Bloomberg and Value Line market risk premiums, then added the current and near-term risk-free rates to the results (Exh. ES-RBH-Rebuttal-6). Based on this analysis, NSTAR Gas calculated (1) four CAPM results for cost of equity ranging from 8.83 percent to 12.01 percent using data from Bloomberg and (2) four CAPM results for cost of equity ranging from 10.01 percent to 13.72 percent using data from Value Line (Exh. ES-RBH-Rebuttal-6).

NSTAR Gas also submitted an ECAPM analysis (Exhs. ES-RBH-1, at 22, 66; ES-RBH-Rebuttal-6). The ECAPM is intended to adjust for the CAPM's tendency to understate returns for companies with low betas, such as utilities, and overstate returns for companies with relatively high betas (Exh. ES-RBH-1, at 22, 67). Specifically, a CAPM analysis for a company with betas below 1.0 will understate the required return (Exh. ES-RBH-1, at 67-68). Conversely, a CAPM analysis for a company with a beta above 1.0 will overstate the required return, with the difference becoming greater as the beta increases (Exh. ES-RBH-1, at 67-68). In addition, according to the Company, the correlation between the proxy group companies and the S&P 500 has declined since 2014, while the relative risk has increased, the CAPM in the form presented by the Company may not adequately reflect the expected systematic risk and, therefore, the returns required by investors for low-beta coefficient companies such as utilities (Exh. ES-RBH-1, at 65-66). To correct for this possible inadequacy, the Company calculates the product of the adjusted beta coefficient and the market risk premium and applies a weight of 75.0 percent to that result (Exh. ES-RBH-1, at 66). The ECAPM model then applies a 25.0-percent weight to the market risk premium, without any effect from the beta coefficient (Exh. ES-RBH-1, at 66). Using the same data and approach as was used in its CAPM analysis, application of the Company's ECAPM resulted in eight individual cost of equity calculations, ranging from 9.90 percent to 14.04 percent (Exh. ES-RBH-Rebuttal-6).[187]

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 (Exhs. AG-JRW at 22-23; JRW-8, at 1). The equity risk premium is the product of the market risk and the mean beta coefficient for each proxy group (Exhs. AG-JRW at 73; JRW-8, at 1). The market risk premium is the expected return from the stock market minus the risk-free rate of interest (Exh. AG-JRW at 61, 63-64). The beta coefficient is an estimated measure of the systematic risk of an individual stock (Exh. AG-JRW at 61, 63-64). In her initial testimony, the Attorney General's CAPM analysis resulted in a 7.0-percent

187 In its rebuttal testimony the Company updated the results of the ECAPM (Exhs. ES-RBH-Rebuttal-1, at 1; ES-RBH-Rebuttal-6).

ROE (Exh. AG-JRW at 73). The Attorney General provided an updated CAPM analysis with her surrebuttal testimony that resulted in a cost of equity of 6.60 percent for her proxy group (Exh. AG-JRW-Surrebuttal at 36).

In her updated analysis, the Attorney General used a risk-free rate of 3.0 percent, representing the upper bound yield on 30-year U.S. Treasury bonds for the period 2013-2020 (Exhs. AG-JRW-Surrebuttal at 36; JRW-Surrebuttal-3, at 1). The beta coefficient she employed of 0.60 for her proxy group is the median unadjusted beta coefficients of the proxy group firms provided by Value Line (Exhs. AG-JRW at 63-64; JRW-8, at 1, 3). The Attorney General used a market risk premium of 6.0 percent for her proxy group based on the midpoint review of over 30 market risk premium studies, including surveys of companies, chief executive officers, financial forecasters, and financial analysts (Exhs. AG-JRW at 8, 64-73; JRW-8, at 1, 4-8; JRW-Surrebuttal-3, at 1, 4-8).

The Attorney General multiplied the estimated market risk premium of 6.0 percent by the beta coefficient of 0.60 to produce expected equity risk premiums of 3.6 percent for her proxy group (Exhs. AG-JRW-Surrebuttal at 36; JRW-Surrebuttal-3, at 1). The Attorney General then added the risk-free rate of 3.0 percent to her expected equity risk premiums to derive a cost of equity of 6.6 percent for her proxy group (Exhs. AG-JRW-Surrebuttal at 36; JRW-Surrebuttal-3, at 1).

c. DOD-FEA's proposal

DOD-FEA's CAPM analysis is based on the results of six different applications of the CAPM (Exhs. DOD-CCW-1, at 52; DOD-CCW-18; DOD-CCW-Surrebuttal-12).[188] The first three results presented are based on the Company's proxy group's current average beta of 0.63 percent, a projected risk-free rate of 1.80 percent, and three market risk premiums estimates of 8.4, 9.30, and 10.30 percent, producing a range of costs of equity from 7.08 to 8.27 percent (Exhs. DOD-CCW-1, at 52; DOD-CCW-18; DOD-CCW-Surrebuttal-12). The last three results presented are based on the Company's proxy group's historical beta of 0.73 percent, a projected risk-free rate of 1.80 percent, and three market risk premiums estimates of 8.40, 9.30, and 10.30 percent, producing a range of costs of equity from 7.91 to 9.29 percent (Exhs. DOD-CCW-1, at 53; DOD-CCW-18; DOD-CCW-Surrebuttal-12). Based on these results, DOD-FEA recommends using a CAPM estimate for cost of equity of 9.50 percent (Exh. DOD-CCW-1, at 53).

d. 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 85; Attorney General Reply Brief at 32). According to the Attorney General, the Company's primary errors are with its use of inflated market risk premiums of 12.08 percent and 12.36 percent

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188 DOD-FEA updated the results of its CAPM analysis as of May 21, 2020 (Exh. DOD-CCW-Surrebuttal-12).

(Attorney General Brief at 85, citing Exh. AG-JRW at 87-95; Attorney General Reply Brief at 32).[189] Further, the Attorney General contends that the Company's long-term EPS growth rates of 12.28 percent and 12.39 percent are overstated (Attorney General Brief at 87).

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 six to seven percent range (Attorney General Brief at 87). 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 4.2 percent to 4.5 percent for projected long-term GDP growth rate forecasts (Attorney General Brief at 88, citing Exhs. AG-JRW at 94-97).

Finally, the Attorney General argues that the gas distribution industry is among the lowest in the U.S. as measured by beta and that betas for electric utilities have been declining in recent years, which indicates the risk of the energy industry has declined and therefore, she concludes that the cost of equity capital for this industry as measured by beta is the lowest in the U.S. (Attorney General Brief at 99, citing Exh. AG-JRW at 71-74). 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 83-86).

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189 The Attorney General refers to the market risk premium figures and long-term EPS growth rates from the Company's initial filing, not those in the Company's updated CAPM (Attorney General Brief at 85, citing Exh. AG-JRW at 87-95).

ii. DOD-FEA

DOD-FEA maintains that 9.5 percent is a reasonable estimate of the Company's ROE using the CAPM model (DOD-FEA Brief at 8-11; DOD-FEA Reply Brief at 3, 5). DOD-FEA argues that NSTAR Gas's CAPM estimates are inflated and unreliable because the Company uses substantially overstated expected market returns (DOD-FEA Brief at 16-17). DOD-FEA asserts that NSTAR Gas's market growth rates of 12.20 percent and 12.29 percent are far too high to be a rational outlook for sustainable, long-term market growth considering that they are more than 2.9 times the expected long-term growth rate of the U.S. economy, with individual company growth rates as high as 95.20 percent (DOD-FEA Brief at 16). Additionally, DOD-FEA contends that NSTAR Gas erroneously overstated the market risk premium in its CAPM analysis (DOD-FEA Brief at 17).

iii. Company

The Company argues that the Attorney General's CAPM calculation must be rejected because it does not reflect fundamental risk/return relationships (Company Brief at 370, citing Exh. ES-RBH-Rebuttal-1 at 49). For example, the Company contends that some of the Attorney General's equity risk premium estimates do not make either theoretical or practical sense (Company Brief at 370, citing Exh. ES-RBH-Rebuttal-1, at 49). For example, the Attorney General's witness references a website market-risk-premia.com, which suggests a CAPM estimate only 46 basis points above the Company's embedded cost of debt (Company Brief at 370, citing Exh. ES-RBH-Rebuttal-1 at 49). 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 370, citing Exh. ES-RBH-Rebuttal-1, at 47-49).

Finally, the Company dismisses the Attorney General's claim that reliance on analysts' forecasts invalidates the Company's CAPM approach (Company Brief at 371, citing Exh. ES-RBH-Rebuttal-1 at 87). 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 371, citing Exh. ES-RBH-Rebuttal-1 at 43).

e. 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. D.P.U. 17-170, at 298; D.P.U. 15-155, at 370; D.P.U. 10-114, at 318; D.P.U. 10-70, at 270; D.P.U. 08-35, at 207; 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 we have 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 CAPM is based on investor expectations and, therefore, it is appropriate to consider a prospective measure for the risk-free rate component. D.P.U. 17-170, at 299; D.P.U. 15-155, at 371. Nonetheless, the Department notes that while the near-term projected yield of the 30-year U.S. Treasury bond was higher than the current yield in the Company's filing, both the current yield and projected yields have fallen since that time

(Exhs. ES-RBH-7; ES-RBH-Rebuttal-6).[190] The Department also acknowledges the Attorney General's point that forecasts of increasing interest rates have been wrong for a decade (Exh. AG-JRW at 16).

Because the CAPM is considered an ex-ante, forward-looking model that recognizes that investors are generally risk averse and will demand higher returns in exchange for assuming higher levels of investment risk (Exhs. AG-JRW at 66-67; JRW-8, at 5-6), the Department finds that the Company's approach based on DCF analyses is less reliable than the survey results of financial professionals. D.P.U. 17-170, at 299; D.P.U. 15-155, at 371; D.P.U. 13-90, at 225-226; D.P.U. 13-75, at 314.

The Company developed a market risk premium imputing an expected market return by applying a DCF analysis to the analysts' earnings growth forecasts of Bloomberg and Value Line (Exhs. ES-RBH-1, at 64; ES-RBH-7). While the results may be indicative of investors' short-term expectations, the Department finds that they overstate the long-term expectations of investors.

In spite of the Company's assertion that capital appreciation rates of 12.28 percent to 12.39 percent, as reported by the Attorney General, and higher actually have occurred quite often in the United States during the period 1926 to 2019, there is no evidence in the record to suggest that the United States will experience a subsequent century of such prolific

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190 As of October 26, 2020, the yield was at 1.59 percent. Federal Reserve Bank of St. Louis (available at https://fred.stlouisfed.org/series/DGS30 (last visited October 26, 2020).)

economic growth. To the contrary, GDP growth has been continually slowing during the past five decades (Exh. AG-JRW-10, at 5). Therefore, the Department finds the Company's calculations of expected market returns and, consequently, its calculations of the market risk premiums are overstated. In estimating a market risk premium, the Attorney General has relied on over 30 surveys of and studies by financial professionals, academics, and market analysts from the last ten years (Exhs. AG-JRW at 8-9; 66-67, AG-JRW-8, at 5-6). The Company has challenged the veracity of several of the surveys relied on by the Attorney General. These surveys appear to be based on limited sample data, and we, thus, place little weight on their results (Exh. ES-RBH-Rebuttal-1, at 47-49). To the extent that DOD-FEA developed its market risk premium analyses relying on a more comprehensive DCF based method from sources other than analysts' earnings growth forecasts from Bloomberg and Value Line, the Department places slightly more weight on DOD-FEA's CAPM results (Exh. DOD-CCW-18).

Considering the infirmities inherent in the CAPM approach as mention above, the Department will place limited weight on the results of the respective CAPM estimates in determining the appropriate ROE.

7. Risk Premium Model

a. Company's Proposal

The risk premium method of determining the cost of equity recognizes that common equity capital is riskier than debt from an investor's standpoint, and that investors require higher returns on stocks than on bonds to compensate for the additional risk (Exh. ES-RBH-1, at 22-23). 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 a calculation of current equity return requirements. D.P.U. 13-75, at 316, n.201. In the 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. ES-RBH-1, at 22-23, 70). The Company relied on data from 1,123 gas utility proceedings between January 1, 1980 and September 30, 2019 (Exhs. ES-RBH-1, at 70; ES-RBH-8). To account for the variability of bond interest rates and allowed ROEs, particularly during the 1980s and the post-Lehman bankruptcy period,[191] the Company used a semi-log regression[192] (Exhs. ES-RBH-1, at 71; ES-RBH-8).

The Company calculated the average 30-year U.S. Treasury yield over the average lag period between utility filings and public utility commission final order issuance, to reflect the prevailing interest rates during the proceedings (Exh. ES-RBH-1, at 70). The Company states that there is a statistically significant inverse relationship between interest rates and utility equity risk premiums (Exh. ES-RBH-1, at 72, citing Roger A. Morin, Ph. D., New Regulatory Finance, Public Utilities Reports, Inc. 2006, at 128). The Company then applied its risk premium to three different 30-year U.S. Treasury yields: (1) a current yield of

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191 The financial services firm Lehman Brothers Holdings, Inc. filed for bankruptcy on September 15, 2008, triggering a one-day drop in the Dow Jones Industrial Average of 4.5 percent and the ensuing 2008 financial crisis, which ushered in the Great Recession.

192 When data is non-linear, a semi-log regression is often used by transforming the dependent variable and allowing linear regression analysis. Because the log of negative numbers is undefined, the use of a semi-log regression can be inappropriate in some circumstances.

2.11 percent, (2) a near-term projected yield of 2.28 percent, and (3) a long-term projected yield of 3.70 percent (Exh. ES-RBH-1, at 73).[193] Based on this analysis, the Company's equity risk premium model produces a ROE between 9.96 percent and 10.01 percent (Exhs. ES-RBH-1, at 73, Table 12).

b. DOD-FEA's Proposal

DOD-FEA's risk premium model is based on two estimates of an equity risk premium: (1) estimating the difference between the required return on utility common equity investments and U.S. Treasury bonds and (2) estimating the difference between common equity returns and contemporary A-rated utility bond yields by Moody's (Exhs. DOD-CCW-1, at 38; DOD-CCW-13; DOD-CCW-14). For both estimates, DOD-FEA used regulatory commission-authorized gas returns as the proxy for the required return on utility common equity (Exhs. DOD-CCW-1, at 38; DOD-CCW-13; DOD-CCW-14).

In estimating the risk premium on Treasury bonds, DOD-FEA measured the difference between utility common equity returns and U.S. Treasury bond yields on an annual basis for each year over the period 1986 through 2019, noting that utility stocks consistently traded at a premium to book value (Exhs. DOD-CCW-1, at 38; DOD-CCW-13). This analysis produced a range of equity risk premiums over U.S. Treasury bond yields of

193 The Company revised the thirty-year Treasury yields to (1) a current yield of 1.37 percent, (2) a near-term projected yield of 1.75 percent, and (3) a long-term projected yield of 3.45 percent resulting in an ROE between 9.92 percent and 10.35 percent (Exh. ES-RBH-Rebuttal-7, at 1).

4.17 percent to 6.83 percent for five-year averages, and 4.30 percent to 6.57 percent for ten-year averages (Exhs. DOD-CCW-1, at 38; DOD-CCW-13). DOD-FEA incorporated five- and ten-year rolling average risk premiums over the study period to gauge risk premium variability over time and to mitigate the impact of anomalous market conditions and skewed risk premiums over an entire business cycle (Exh. DOD-CCW-1, at 39).

The risk premiums over contemporary Moody's A-rated utility bond yields ranged from 2.80 percent to 5.62 percent for the five-year rolling average and 3.11 percent to 5.42 percent for the ten-year rolling average (Exhs. DOD-CCW-1, at 38; DOD-CCW-14). DOD-FEA weighted the resulting high-end risk premiums more heavily than the low-end risk premiums and determined a range of U.S. Treasury bond and utility bond risk premiums between 4.13 percent and 5.49 percent that resulted in ROEs of 8.9 percent to 9.3 percent (Exhs. DOD-CCW-1, at 42; DOD-CCW-13; DOD-CCW-14).

c. 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 91). 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 U.S. Treasury yields, and then is applied to projected U.S. Treasury yields that are always forecasted to increase (Attorney General Brief at 91-92, citing Exh. AG-JRW at 105-108). 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 92, citing Exh. AG-JRW at 105-108). 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 91, citing Exh. AG-JRW at 105-108). Third, 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 91, citing Exh. AG-JRW at 105-108).

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 92, citing Exh. AG-JRW at 105-108). Finally, the Attorney General argues that the Company's method produces an inflated cost of equity because utilities have been selling at market-to-book ratios well in excess of 1.0 for many years (Attorney General Brief at 92, citing Exh. AG-JRW at 105-108). As such, these high market-to-book ratios indicate that the authorized and earned rates of return on equity have been greater than the return that investors require (Attorney General Brief at 92, citing Exh. AG-JRW at 105-108).

ii. DOD-FEA

DOD-FEA contends that the Company's reliance on a long-term projected interest rate of 3.7 percent is significantly above any recent interest rate projection, or current level and, therefore, a projected interest rate of no higher than 2.6 percent should be used instead

(DOD-FEA Brief at 18). Further, DOD-FEA argues that the predictive strength of the Company's regression model weakens in the post-recession time period (DOD-FEA Brief at 18).[194] For example, the Company's R-square value is 78.85 percent when measuring the time period from January 1980 through September 2019 (DOD-FEA Brief at 19). However, when only measuring the relationship between the risk premium and interest rates over the 2010 through September 2019 post-recession time period, the R-square measure declines to 48.39 percent (DOD-FEA Brief at 19, citing Exh. DOD-CCW-1, at 76). DOD-FEA claims that this perspective shows a weakening of the statistical predictability of the Company's regression analysis vis-à-vis interest rates and risk premiums data (DOD-FEA Brief at 19). For these reasons, DOD-FEA argues that the Company's belief that equity risk premiums can be gauged by only changes in interest rates is not supported by its own regression analysis (DOD-FEA Brief at 19).

iii. 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 372-373). The Company argues that regulatory decisions reflect market-based analyses (Company Brief at 372, citing Exh. ES-RBH-Rebuttal-1, at 65).

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[194] The strength of a relationship between the dependent variable (risk premium) and the independent variable (nominal interest rates) in a regression analysis is best explained in the R-square value (DOD-FEA Brief at 18-19). Specifically, the R-square measures how much explanatory power changes in the independent variable has on changes in the independent variable whereby a higher variable indicates a strong relationship (DOD-FEA Brief at 18-19).

Further, the Company maintains that because authorized returns are publicly available, such data are, to some degree, reflected in investors' return expectations and requirements (Company Brief at 372, citing Exh. ES-RBH-Rebuttal-1, at 65). For these reasons, the Company argues that authorized returns are a reasonable measure of investor-required returns (Company Brief at 372, citing Exh. ES-RBH-Rebuttal-1, at 65). Finally, the Company maintains that the Department has viewed the risk premium approach as a "supplemental approach" in determining an ROE and that the Company has used it in that manner here (Company Brief at 373, citing D.P.U. 07-71, at 137).

d. Analysis and Findings

The Department has repeatedly found that a risk premium analysis can overstate the amount of company-specific risk and, therefore, the cost of equity. D.P.U. 10-114, at 322; 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, 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. 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.T.E. 02-24/25, at 228, citing D.T.E. 99-118, at 86-87.

The Department finds several flaws inherent in the risk premium analysis presented by the Company. First, as the Department has previously recognized, there is a 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. Moreover, the Company's approach presumes that allowed ROEs are determined on a purely quantitative basis. As we note below, management performance and other qualitative factors are significant parts of the determination of an appropriate ROE; to the extent that allowed ROEs incorporate some type of penalty for deficient management or, conversely, recognize superior management, the results of the comparative analysis will either tend to understate or overstate the required risk premium.

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 U.S. Treasury debt yields provides a better approach. D.P.U. 17-170, at 303; D.P.U. 15-155, at 375; D.P.U. 09-39, at 388-389; D.P.U. 08-35, at 202-203; D.P.U. 90-121, at 171. The Company relies on the projected U.S. Treasury rates in this model, arguing that setting an ROE for a company is forward looking and that, therefore, using the forward-looking approach is appropriate (Company Brief at 372). The Department disagrees. The risk premium model is based on current market conditions and is not a forward-looking approach. D.P.U. 13-75, at 319; D.P.U. 12-25, at 433. Accordingly, the Department finds that current U.S. Treasury yields are more appropriate than the forward-looking approach created by the use of projected yields in a risk premium analysis. For these reasons, the Department finds that NSTAR

Gas's risk premium model overstates the required ROE for the Company and has limited value in setting the Company's ROE.

8. Flotation Costs

a. Company's Proposal

The Company factors flotation costs into its proposed ROE and assert 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. ES-RBH-1, at 26). According to the Company, flotation costs represent a permanent reduction to common equity and, therefore, they should be recovered similar to the recovery of debt issuance costs (Exh. ES-RBH-1, at 26).

To determine flotation costs, the Company used the weighted average of the most recent open market common stock issuances for the proxy group and Eversource Energy, then modified the DCF calculation to derive the dividend yield that would reimburse investors for direct issuance costs to develop a flotation cost estimate of 0.08 percent (Exhs. ES-RBH-1, at 28; ES-RBH-10). NSTAR Gas states, however, that it did not simply increase its proposed ROE by eight basis points to reflect the effect of the flotation costs (Exh. ES-RBH-1, at 28). Instead, the Company states that it took into consideration flotation costs when determining where the Company's cost of equity falls within the range of analytical results produced by the various cost of equity models (Exh. ES-RBH-1, at 28).

b. Positions of the Parties

i. Attorney General

The Attorney General argues that the Company has not identified any flotations costs (Attorney General Brief at 72). The Attorney General argues that there is no reason to allow NSTAR Gas to receive higher revenues in the form of a higher ROE for expenses that it does not incur (Attorney General Brief at 72).

ii. Company

The Company argues that flotation costs are true and necessary costs, representing funds that otherwise would be invested in long-lived assets, and, if left unrecovered, the Company is denied an opportunity to earn a portion of its required return (Company Brief at 372-373, citing Exh. ES-RBH-Rebuttal-1, at 78). Nevertheless, the Company emphasizes that it did not make a specific adjustment for flotation costs to its proposed ROE, but only considered the effect of flotation costs in combination with other factors determining the appropriate ROE (Company Brief at 360, citing Exh. ES-RBH-1, at 28). No other party addressed this issue on brief.

c. Analysis and Findings

NSTAR Gas asserts that it is appropriate to consider flotation (issuance) costs in determining its allowed ROE based on the average issuance costs of issuing equity that were incurred by the proxy group companies in their most recent two issuances (Exhs. ES-RBH-1, at 28). 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.

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 Eversource Energy and, therefore, has no publicly-traded stock on which to incur flotation costs[195] (Exh. ES-RBH-1, at 15). For these reasons, the Department does not take flotation costs into consideration when determining the Company's ROE.

9. Cost of Equity Impact of Revenue Decoupling and PBRM

a. Introduction

All companies in the Company's proxy group have some form of revenue decoupling or revenue stabilization mechanisms (Exhs. ES-RBH-Rebuttal-1, at 24; ES-RBH-Rebuttal-9). Revenue decoupling is common among natural gas utilities (Exh. ES-RBH-Rebuttal-1, at 24).

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195 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 Eversource Energy (Exh. ES-DPH/ANB-1, at 124).

b. Positions of the Parties

i. Attorney General

The Attorney General rejects the Company's position that revenue decoupling and PBRM does not reduce NSTAR Gas's risk relative to the gas companies in its proxy group, notwithstanding the Company's view that most of the proxy utilities have revenue decoupling mechanisms as well as rate mechanisms that cover energy efficient costs, renewable energy investments, and, in some cases, formula-based rate plans (Attorney General Brief at 72, citing Exh. ES-RBH-1, at 35). The Attorney General contends that the Company's revenue decoupling and proposed PBRM cover a much higher percentage of gas revenues than those in place for the Company's proxy group (Attorney General Brief at 72, citing Exh. AG-JRW at 113-115). Further, the Attorney General explains that the Company's PBRM proposal reduces the Company's risk relative to other gas companies for the following reasons: (1) the Company's proposed Z factor adjusts rates for certain tax, accounting, and other regulatory/law changes that apply exclusively to the gas distribution business, and the inflation and productivity factor calculations would cover other cost adjustments associated with general finance, economy, and accounting changes; (2) the Company has specifically included the costs "arising due to pipeline safety requirements imposed after November 8, 2019, which demonstrated cost impacts on or after the start date of the PBRM, or November 1, 2020"; and (3) the Company's PBRM stay-out provision occurs only if the Company receives the entirety of its requested revenue requirement increase and the Department allows the entirety of the Company's proposed PBRM formula (Attorney General Brief at 73). The Attorney General avers that, although there is a stay-out provision in the proposed PBR Plan, there is no such provision that legally prevents NSTAR Gas from filing for approval of a base distribution rate increase (Attorney General Brief at 72).

ii. Company

NSTAR Gas argues that its proposed PBRM does not reduce the Company's risk (Company Brief at 373). First, according to the Company, the exogenous factor allows for the recovery of significant costs beyond the control of the utility (Company Brief at 373, citing Exh. ES-RBH-1, at 80-81). In the Company's view, this factor is comparable in certain ways to recovery mechanisms that many utilities already have to recover significant costs beyond their control (Company Brief at 373, citing Exh. ES-RBH-1, at 80-81). Second, the five-year stay-out provision in the PBRM makes it more difficult for the Company to request a modification in rates (Company Brief at 373, citing Exh. ES-RBH-1, at 81). Third, the Company notes that the Department has stated that breaking a five-year stay-out provision before the end of a PBR should be a "last resort" decision to avoid any possible negative effect on the Company's ROE if and when a Section 94 proceeding is initiated (Company Brief at 374, citing D.P.U. 17-05, at 404). Fourth, the Company also notes that the Department has concluded that "a five-year stay-out provision could increase a company's risks in meeting its financial requirements" (Company Brief at 374, citing D.PU. 17-05, at 404).

For these reasons, the Company asserts that there is no evidence that it will be less risky because of the PBRM, and any downward adjustment in the ROE for the implementation of its PBRM would be inappropriate (Company Brief at 374, citing D.P.U. 18-150, at 495).

c. Analysis and Findings

In D.P.U. 07-50-A, the Department stated that, because revenue decoupling is designed to ensure that distribution companies' revenues are not adversely affected by reductions in sales, by definition, revenue 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 revenue 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.

All companies in the Company's proxy group have some form of revenue decoupling or revenue stabilization mechanisms (Exhs. ES-RBH-Rebuttal-1, at 24; ES-RBH-Rebuttal-9). 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 revenue decoupling, weather normalization, straight fixed variable rate design, and conservation incentive programs (Exh. ES-RBH-Rebuttal-9). Therefore, the fact that the comparison groups of companies have revenue stabilization mechanisms does not mean that the comparison groups fully match the risk profile of the Company. Investors who consult a company's 10-Q and 10-K filings with the SEC are sufficiently astute 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's argument that there is no need to consider the equity cost impact of revenue 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 revenue 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.

The same considerations apply to our assessment of the impact of the Company's proposed PBRM to reduce NSTAR Gas's earnings volatility. Therefore, based on the evidence and arguments presented in this case, the Department will consider the impact of the Company's revenue decoupling mechanism as well as its proposed PBRM on its allowed ROE.

Accordingly, the Department will examine the specific risk profile of the Company, and the specific features of the Company's current revenue decoupling and reconciling mechanisms as well as the Company's proposed PBRM to arrive at the appropriate determination of the effect of risk on the Company's required ROE.

10. Conclusion

The standard for determining the allowed ROE is set forth in Bluefield and Hope. 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. Bluefield at 692-693; Hope at 603. 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 10.45 percent (Exhs. ES-RBH-1, at 3; ES-RBH-Rebuttal-1, at 2). The Attorney General recommends a primary ROE of 9.0 percent using her proposed capital structure along with an alternative ROE of 8.75 using the Company's proposed capital structure (Exhs. AG-JRW at 39; AG-JRW-Surrebuttal, at 38-39).[196] DOD-FEA recommends an ROE of 9.3 percent (Exh. DOD-CCW-Surrebuttal-1, at 13).

The Department has found that both quantitative and qualitative factors must be taken into account in determining an allowed ROE. 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.

The use of empirical analyses in this context is not an exact science. D.P.U. 17-170, at 305; D.P.U. 15-155, at 377; see also, United Railways & Electric Company of Baltimore v. West, 280 U.S. 234, 250 (1930) (what will constitute a fair return is not capable of exact mathematical demonstration); Southern Bell Telephone and Telegraph Company v. Louisiana

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196 The Attorney General did not update her alternative ROE proposal on her surrebuttal testimony but included it on her brief (Attorney General Brief at 68-68).

Public Utility Commission, 239 La. 175, 225 (1960) (ascertainment of a fair return in a given case is a matter incapable of exact mathematical demonstration). Conducting a model-based ROE analysis requires the analyst to make a number of subjective judgments. 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.

In support of its recommended ROE, NSTAR Gas has presented quantitative analyses using the DCF model, the CAPM model, and the Bond Yield Plus Risk Premium model, each incorporating the financial data of its proxy group and an expected earnings approach to corroborate the outcomes of such models (Exh. ES-RBH-1, at 3, 6-7). The Attorney General has presented her analyses using the DCF and the CAPM models, incorporating the financial data of her proxy group (Exhs. AG-JRW at 4, 60 at Table 5, 73 at Table 6). DOD-FEA has presented its analysis using (1) a constant growth DCF model using the consensus of analysts' growth rate projections; (2) a constant growth DCF using sustainable growth rates estimates; (3) a multi-stage growth model; (4) the CAPM model; and (5) a risk premium model (Exh. DOD-CCW-1, at 19-20).

As discussed above, the evidence demonstrates that each cost of equity model used by the Company, Attorney General, and DOD-FEA suffers from a number of simplifying and restrictive assumptions. Applying these assumptions to the financial data of a proxy group 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 the Company and intervenors, including the simplifying assumptions that underlie the constant growth form of the model and its element of circularity. These shortcomings notwithstanding, the DCF model relies on classical valuation theory focusing on the intrinsic value of a company's stock as determined by the Company's anticipated earning power and, as such, is a powerful tool in developing the appropriate cost of equity (Exhs. ES-RBH-1, at 19; AG-JRW at 48).

The Department further finds that the CAPM analyses relied upon by the Company, Attorney General, and DOD-FEA also are flawed because of the simplifying assumptions underlying CAPM theory and the subjectivity inevitable in estimating market risk premiums. Specifically, we find that the Company's risk premium approach suffers from a number of limitations and tends to overstate NSTAR Gas's required ROE.

While the results of analytical models are useful, the Department must ultimately apply its own judgment to the evidence to determine an appropriate ROE. We must apply to the record evidence and argument considerable judgment and agency expertise to determine the appropriate use of the empirical results. Our task is not a mechanical or model driven exercise. D.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.[197] The Department must account for additional factors specific to a company that may not be reflected in the results of the models.

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[197] As the Department stated in New England Telephone and Telegraph Company, D.P.U. 17441, at 9 (1973):

We note that a portion of the revenues of the companies in the proxy groups are derived from unregulated and competitive lines of business (Exhs. ES-RBH-1, at 17; JRW-2, at 1). 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 the comparability standard, we will consider such risk differentials when weighing the results of the models used to calculate the Company's allowed ROE. In addition, while the Department accepts the capital structure as proposed by the Company, we recognize that the Company has a higher common equity ratio than that of its proxy group and, therefore, less financial risk, which we take into consideration when establishing the cost of equity.

In addition, the Company and the Attorney General debate the cause and effect connection between rate mechanisms, including PBRM, and the cost of equity in the context of their respective proxy groups (Exhs. ES-RBH-1, at 35; ES-RBH-Rebuttal-1, at 80-81; AG-JRW at 27; AG-JRW-Surrebuttal at 25-26; AG 7-26). The Company states that determining the revenue affected by rate mechanisms would require complex analyses relying on multiple assumptions and the cost recovery mechanisms often address company-specific issues and, as such, comparing the revenue recovered under one mechanism is of limited value in assessing the cost of equity (Exh. AG 7-26). Although many companies in both

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> 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.

proxy groups employ some form of revenue stabilization or revenue decoupling mechanism, the Department agrees with the Company that the degree of revenue stabilization varies among the companies and precisely quantifying their relative effects on the required ROE in this proceeding is impractical. Nonetheless, we take these uncertainties into consideration when determining an ROE.

First we'll discuss factors that the Department considers that would reduce the Companies allowed ROE. In determining the allowed ROE, we have considered NSTAR Gas's specific rate mechanisms. In particular, the Department established in this Order a PBRM that, among other things, allows the Company to implement an annual rate adjustment to provide revenue support for expenses and capital investment (see Section V.B.4, above). The resulting more timely and flexible cost recovery serves to reduce a company's risks. Further, we consider NSTAR Gas's reconciling mechanisms. The Department previously approved a revenue decoupling mechanism for NSTAR Gas in D.P.U. 14-150, at 16-23, and has directed all gas and electric distribution companies to file for revenue decoupling in a base distribution rate proceeding. D.P.U. 07-50-A at 84. The Department has found that revenue decoupling mechanisms can act to reduce the variability of a company's revenues and, consequently, reduces its financial risks. D.P.U. 09-39, at 398; D.P.U. 09-30, at 371-372; D.P.U. 07-50-A at 72-73. In addition to the revenue decoupling mechanism, the Department considers NSTAR Gas's use of reconciling mechanisms to recover certain costs, dollar-for-dollar, outside of base distribution rates. The Company presently has in place fully reconciling mechanisms for a range of expenses, including GSEP, gas costs, energy efficiency costs, pension/PBOP expense, Attorney General consultant costs, and supply-related bad debt. As a result of this Order, NSTAR Gas will retain these reconciling mechanisms. The use of these reconciling mechanisms covering a significant portion of the Company's expenses combined with elements of the PBR Plan results in lower risk for NSTAR Gas than otherwise would be the case.

Next the Department discusses factors that it takes into consideration that increase the risk for the Company. First, in this case, the Department set a ten-year stay-out provision as part of the Company's PBRM, significantly longer than recent stay-out provisions which increases the Company's risks in meeting its financial requirements. See, e.g., D.P.U. 17-05, at 404 (five years); D.P.U. 18-150, at 55-56 (five years). Next, we consider the regulatory uncertainty for the gas industry regarding increased safety requirements and an increased commitment to reduction of greenhouse gas emissions through a possible near-term restriction in the use of natural gas, which the Department will investigate during the term of the Company's stay-out provision. D.P.U. 20-80, Vote and Order Opening Investigation at 3-6 (developing a regulatory and policy roadmap on or before March 1, 2022 to guide the evolution of the gas distribution industry). Additionally, irrespective of evolving clean energy policy, the Company states that it is experiencing a decline in customer additions due to on-main saturation coupled with an increasing cost of connection for off-main customers. (Exhs. ES-DPH/ANB-1, at 152-154; DPU-ES 14-5; Tr. 4, at 531). In Massachusetts, the effects of the Merrimack Valley incident will certainly influence investors' risk assessment of NSTAR Gas, and investors might be similarly influenced by local attempts, though unsuccessful, to restrict natural gas use, such as by the Town of Brookline. In setting this ROE, the Department has taken into account the potential enactment of additional gas safety regulations that may increase NSTAR Gas's costs in response to the heighted focus on reductions in gas leaks and an added focus on safety, all of which likely will affect the financial and business risk profile of the Company in particular, and the gas industry in general.[198,199]

Finally, there are other qualitative factors that the Department will consider in determining a company's allowed ROE. It is both the Department's long-standing

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198 Dynamic Risk Assessment Systems, Inc, Commonwealth of Massachusetts Assessment of Pipeline Safety, Phase I Summary Report, May 13, 2019, at 3.

199 Inquiry by the Department of Public Utilities, on its own motion, into the use of professional engineers by natural gas companies pursuant to G.L. c. 164, Section 148, as added by St. 2018, c. 339, Section 2., Vote and Order Opening Inquiry, March 18, 2019.

precedent[200] and accepted regulatory practice[201] to consider qualitative factors such as management 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,

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200 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. 17-170, at 312-313 (corporate irresponsibility warranted ROE at lower end of reasonableness range); D.P.U. 12-86, at 275-276 (deficiencies regarding affiliate transactions and selection of rate case consultants warranted ROE at lower end of reasonable range); D.P.U. 11-43, at 220-222 (company's improper handling of 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 424-427 (company shortcomings in storm response warranted ROE at lower end of reasonable range); D.P.U. 10-114, at 339-341 (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); D.P.U. 85-266-A/271-A at 172-173 (failure to fulfill public service obligations warranted ROE at lower end of reasonable range).

201 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); 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); 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 be considered in fixing the just and reasonable rate therefore).

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 end or lower end of the reasonable range based on above-average or subpar management performance and customer service. See, e.g., D.P.U. 09-39, at 399-400 (company's storm response and rapid restoration of service warranted ROE at the higher end of the reasonable range); D.P.U. 12-86, at 274-276 & n.181 (deficiencies regarding affiliate transactions and selection of rate case consultants warranted ROE at lower end of reasonable range); D.P.U. 11-01/D.P.U. 11-02, at 424, 427 (company shortcomings in storm response warranted ROE at lower end of reasonable range); D.P.U. 17-170, at 310-312 (ROE warranted being set at the lower end of reasonable range for disregard to federal and state safety regulations and poor management of assets). In this case, we have found no evidence of any deficiencies in Eversource's communications or management practices, and based on this consistent and professional commitment to customer safety and service we do not find any basis to warrant a downward adjustment to NSTAR Gas's allowed ROE.

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 9.9 percent is within a reasonable range of rates that will preserve NSTAR Gas'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 this finding, the Department has considered both qualitative and quantitative aspects of the parties' various methods for determining the

Company's ROE, as well as the arguments of and evidence presented by the parties in this proceeding.

# XII. RATE STRUCTURE

## A. Rate Structure Goals

Rate structure defines the level and pattern of prices charged to each customer class for its 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 structure 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. 17-170, at 313; D.P.U. 14-150, at 368; D.P.U. 13-75, at 330.

Efficiency means that the rate structure should allow a company to recover the cost of providing the service and provide an accurate basis for consumers' decisions about how to best fulfill their needs. The lowest-cost method of fulfilling consumers' needs should also be the lowest-cost means for society as a whole. Thus, efficiency in rate structure means it is cost based and recovers the cost to society of the consumption of resources to produce the utility service. D.P.U. 17-170, at 313-314; D.P.U. 14-150, at 368; D.P.U. 13-75, at 330.

The Department has determined that a rate structure achieves the goal of simplicity if it is easily understood by consumers. Rate continuity means that changes to rate structure should be gradual to allow consumers to adjust their consumption patterns in response to a change in structure. Fairness means that no class of consumers should pay more than the costs of serving that class. Earnings stability means that the amount a company earns from its rate should not vary significantly over a period of one or two years. D.P.U. 17-170, at 314; D.P.U. 14-150, at 369; D.P.U. 13-75, at 331.

There are two parts to determining rate structure: cost allocation and rate design. The cost allocation step assigns a portion of a company's total costs to each rate class through an embedded allocated cost of service study ("ACOSS"). 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. 17-170, at 314; D.P.U. 14-150, at 369; D.P.U. 13-75, at 331.

There are four steps to develop an ACOSS. The first step is to functionalize costs. In this step, costs are associated with the production, transmission, or distribution function of providing service. The second step is to classify expenses in each functional category according to the factors underlying their causation. Thus, the expenses are classified as demand-, energy-, or customer-related. The third step is to identify an allocator that is most appropriate for costs in each classification 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 allocators chosen and then to sum for each rate class the costs allocated in order to determine the total costs of serving each rate class at equalized rates of return. D.P.U. 17-170, at 315; D.P.U. 14-150, at 369-370; D.P.U. 13-75, at 332.

The results of the ACOSS are compared to revenues collected from each rate class in the test year. If these amounts are reasonably comparable, then the revenue increase or decrease may be allocated among the rate classes so as to equalize the rates of return and ensure that each rate class pays the cost of serving it. If, however, the differences between the allocated costs and the test-year revenues are significant, then, for reasons of continuity, the revenue increase or decrease may be allocated so as to reduce the difference in rates of return, but not to equalize the rates of return in a single step. D.P.U. 17-170, at 315; D.P.U. 14-150, at 370; D.P.U. 13-75, at 332.

As the previous discussion indicates, the Department does not determine rates based solely on the results of an ACOSS, but also explicitly considers the effect of its rate structure decisions on the amount that 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 goal of fairness, the Department also has ordered the establishment of special rate classes for certain low-income customers and has considered the effect of such rates and rate changes on low-income customers. D.P.U. 17-170, at 316; D.P.U. 14-150, at 370-371; D.P.U. 13-75, at 332. 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) (discounted low-income rates). In addition, G.L. c. 164, § 94I ("Section 94I") requires the Department, in each base distribution rate proceeding, to design rates based on equalized rates of return by customer class as long as the resulting impact for any one customer class is not more than ten percent.[202] The Department reaffirms its rate structure goals that are designed to result in rates that are fair and cost-based and enable customers to adjust to changes. D.P.U. 17-170, at 316-317; D.P.U. 14-150, at 371; D.P.U. 13-75, at 333.

The second part of determining the rate structure is rate design. The level of the revenues generated by a given rate structure is governed by the cost allocated to each rate class in the cost allocation process. The pattern of prices in the rate structure, which produces the given level of revenues, is a function of the rate design. The overarching requirement for rate design is that a given rate class 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. 17-170, at 317; D.P.U. 14-150, at 371; D.P.U. 13-75, at 333.

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202 Section 94I provides:

> In each base distribution rate proceeding conducted by the [D]epartment under Section 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.

B. Allocated Cost of Service Study

1. Company Proposal

NSTAR Gas performed an ACOSS that assigns or apportions, based on cost-causation principles, the Company's total cost of service to each rate class (Exh. ES-DAH-1, at 3-4). The most important principle underlying any ACOSS is that cost incurrence should follow cost causation. D.P.U. 17-170, at 318-319; D.P.U. 14-150, at 372; D.P.U. 10-114, at 75. To establish the cost responsibility of each customer class, total operating costs are functionalized (based on characteristics of utility operation), classified (customer-, demand-, or commodity-related), and then allocated to customer classes using internal and external allocation factors (Exh. ES-DAH-1, at 4-5). D.P.U. 17-170, at 319; D.P.U. 14-150, at 372-373; D.P.U. 10-55, at 534.

In the second step (i.e., classification), the Company takes the functional cost elements and classifies them by the factor of utilization most closely matching cost causation (Exh. ES-DAH-1, at 3-4). NSTAR Gas classified its distribution plant as either "demand" or "customer" -related (Exhs. ES-DAH-1, at 7; ES-DAH-2 Sch. 1). In the third step, the Company allocated its demand-related costs on a proportional responsibility ("PR") factor, and the customer costs were allocated on a customer-related basis (Exhs. ES-DAH-1, at 7; AG 26-2). The PR allocator assigns demand costs to the rate classes based on class monthly system loads (Exh. ES-DAH-1, at 7).

NSTAR Gas used the same service classes and allocation factors approved in D.P.U. 14-150, with seven exceptions[203] (Exh. DPU-ES 8-1). In addition, the Company and Attorney General reached the following agreements regarding the Company's ACOSS: (1) use of the residential average cost to allocate service pipe costs for the residential classes; (2) use of the actual embedded cost of each type of meter to allocate meter and meter installation costs; and (3) allocation of house regulator costs to customers who are not located on low pressure systems (ES-AG Stipulations at 5).

2. Positions of the Parties

a. DOD-FEA

The DOD-FEA raises two issues regarding the Company's ACOSS (DOD-FEA Brief at 20-21). Specifically, the DOD-FEA claims that (1) the Company's allocation of demand related costs is flawed, and (2) the cost of distribution mains is inappropriately classified as solely a demand-related cost (DOD-FEA Brief at 20-21).

i. Allocation of Demand-Related Costs

The DOD-FEA argues that costs that are classified as demand-related should be allocated to rate classes based on peak day demands (DOD-FEA Brief at 20-21). The DOD-FEA points out that the Company's ACOSS witness has endorsed the DOD-FEA's proposal of a peak day demand allocation through testimony in other jurisdictions (DOD-FEA

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[203] The Company modified its allocations for the following: (1) Account 303, Miscellaneous Intangible; (2) Account 385, Industrial Meter & Regulation; (3) Account 383, House Regulators; (4) depreciation expense for Account 385; (5) depreciation expense for Account 383; (6) Account 893, Maintenance of Meters/House Regulators; and (7) amortization expense costs (Exh. DPU-ES 8-1).

Brief at 21, citing Exh.DOD-MPG-1, at 8-9). The DOD-FEA further asserts that demand-related costs should be allocated based on peak day demand because the Company designs its distribution system to meet customers peak day demands (DOD-FEA Brief at 22, citing Exh. DOD-MPG-3, at 5). Moreover, the DOD-FEA claims that the Company's tariff language of its terms and conditions further reinforces that use of daily peak demand (DOD-FEA Brief at 22-23, citing Exh. DOD-MPG-1, at 10-11). The DOD-FEA asserts that the Company's tariff language encourages customers to manage their daily consumptions and to manage their peak day demand; therefore, fixed capacity costs should be allocated based on peak days (DOD-FEA Brief at 23). The DOD-FEA argues that in order to support conservation through economic signals to ratepayers, the Department should reconsider the Company's rate design methods, regardless of historical precedent (DOD-FEA Reply Brief at 8-9). By reevaluating past practices, the DOD-FEA claims there is an opportunity to improve the economic incentives of conservation and more accurately reflect cost of service in rates (DOD-FEA Reply Brief at 9).

ii. Cost Classification – Distribution Mains

The DOD-FEA objects to the Company's classification of distribution main costs as demand-related costs (DOD-FEA Brief at 24). The DOD-FEA claims that an accurate allocation of distribution main costs would be to classify them as both demand and customer costs (DOD-FEA Brief at 24). The DOD-FEA contends this treatment of distribution main costs is supported by testimony offered by the Company's ACOSS witness in a Virginia case (DOD-FEA Brief at 24 citing Exh. DOD-MPG-3, at 7).

b. TEC

TEC argues that a peak demand allocator should be used for the Company's ACOSS in place of the PR allocator in order to better align rate design with cost causation (TEC Brief at 2; TEC Reply Brief at 3). TEC contends that the Company's mains and gas system are designed to meet peak day demands and that the record demonstrates that hourly flow rates can vary significantly, even on a peak day (TEC Brief at 3, citing Exh. ES-PMC/MRG-1, at 38-39). TEC argues that since distribution costs are driven by meeting peak day demand, the PR method does not satisfy the Bonbright principles of cost causation and fairness (TEC Brief at 3).[204] TEC asserts that the PR method assigns some distribution cost based on a customer's usage on a warm winter day, which does not drive distribution costs (TEC Brief at 3).

TEC further argues that the PR method leads to rate class cross subsidies by assigning a higher demand cost to certain classes than their class's relative contribution to peak day demand (TEC Brief at 3; TEC Reply Brief at 3). Specially, TEC attests that the PR method generates rates where customers in the G-53 rate class, which are often engaged in production, research, and patient care, are subsidizing other rate classes (TEC Reply Brief at 3). Conversely, TEC points out that the DOD-FEA's peak-day allocation factor assigns all

204 The Department's rate structure goals of efficiency, simplicity, continuity, fairness, and earnings stability are an adaptation of, and attributed to, Principles of Public Utility Rates (1961) by James C. Bonbright, Albert L. Danielson, and David R. Kamerschen, and are often referred to as the "Bonbright Principles."

the rate classes a demand cost allocator within one dollar of the system average (TEC Brief at 3, citing Exh. DOD-MPG-1, at 13).

TEC challenges the Company's argument that PR method should be approved because it is Department precedent (TEC Brief at 4). TEC asserts that while the PR method has been used in the Massachusetts in the past, it has never been contested by intervenors or explicitly mentioned in a Department Order (TEC Brief at 4-5). TEC states that the origin of the PR method is based on research presented in a Public Utilities Fortnightly article published 48 years ago, which renders it an outdated resource upon which to rely (TEC Brief at 5). TEC further points out that, based on the Company's representation, Massachusetts is the only jurisdiction which uses the PR method for gas utility ACOSS (TEC Brief at 5, citing Exh. DOD-FEA-NSTAR 1-9(c)).

TEC also contests the Company's assertion that the method proposed by the DOD-FEA would require a long-term mitigation plan to address rate shock (TEC Reply Brief at 4, citing Company Brief at 424-425). TEC contends that the Company has conflated the adoption of a peak demand allocator in its ACOSS with the method proposed by the DOD-FEA (TEC Reply Brief at 4). TEC explains that it supports the DOD-FEA's proposed peak demand allocator, which it states is based on record evidence that illustrates that rate classes would experience an orderly transition to the proposed ACOSS method with a ten-percent overall bill increase cap and 200-percent cap of the average distribution increase (TEC Reply Brief at 4, citing RR-DPU-12).

c. Company

i. Demand-Related Costs

The Company contends that in Massachusetts the PR method for demand allocation costs has been found to be appropriate for over two decades (Company Brief at 399-400, 424; Company Reply Brief at 72, 73, citing Exh. ES-DAH-Rebuttal-1, at 4, 5). NSTAR Gas asserts that the PR method reflects the importance of demands being met through the year, as opposed to the single peak day (Company Brief at 399-400, 424). The Company raises concerns that the demand/customer method as proposed by the DOD-FEA would result in increasing costs assigned to low load factor classes and those with a greater number of customers (Company Brief at 400, 424, citing Exh. ES-DAH-1, at 6). NSTAR Gas further argues that moving to the DOD-FEA's proposed method would require a long-term mitigation plan in order to assuage rate impacts and rate continuity issues (Company Brief at 400, 424-425, citing Exh. ES-DAH-Rebuttal-1, at 5). The Company asserts that if the Department were to adopt the peak day demand allocation method, it should implement a 200-percent cap on any rate class's distribution revenue increase of the system average increase, as opposed to the 175-percent cap agreed upon with the Attorney General (Company Brief at 421-422, citing RR-DPU-12). NSTAR Gas refutes the DOD-FEA's argument that Department policy should spur a reexamination of past rate design methods, since encouraging efficiency has been a prerogative in the past when the PR method was accepted (Company Reply Brief at 73, citing DOD-FEA Reply Brief at 9). The Company further argues that the threshold to depart from Department precedent has not been met since the PR method is long standing policy (Company Reply Brief at 72).

In response to TEC's argument that the use of a peak demand allocator will not result in "rate shock," NSTAR Gas contest that TEC relies on an illustrative analysis provided by the Company that ignores specific agreements made with the Attorney General (Company Reply Brief at 75, citing TEC Reply Brief at 4). Specifically, the Company points out that it agreed with the Attorney General to use a 175-percent cap on the distribution revenue increase received by any class of the system average increase (Company Reply Brief at 75). NSTAR Gas argues that if it were to implement a 200-percent cap as recommended by TEC, it would run contrary to the agreement reached with the Attorney General and require the Company and Attorney General to renegotiate issues that have already been resolved (Company Reply Brief at 75). NSTAR Gas further contests that the argument made by TEC that customers taking service under rate G-53 are being forced to subsidize the other rate classes, and the Company asserts that TEC ignores the fact that commercial and industrial customers are often able to pass on their overhead costs to their customers (Company Reply Brief at 76).

ii. Cost Classification – Distribution Mains

The Company accepts that the classification of distribution main costs as both demand and customer costs, as proposed by the DOD-FEA, is a method that is commonly used in other jurisdictions (Company Brief at 399, citing Exh. DOD-FEA-NSTAR 1-21). However, the Company argues that the Department practice has been to treat these costs a demand-related (Company Brief at 400). Further, as noted above, the Company argues that moving to the DOD-FEA's demand and customer classification proposal would require a long-term mitigation plan to reduce rate impacts (Company Brief at 400, citing Exh. ES-DAH-Rebuttal-1, at 5). Finally, the Company argues that TEC's support of the DOD-FEA's proposal is misplaced because that analysis does not consider the actual customer component percent of mains (Company Reply Brief at 73-74, citing Exh. DOD-MPG-1 at 15; Tr. 4, at 569-571)

### 3. Analysis and Findings

#### a. Introduction

In evaluating the Company's rate design proposals, the Department considers its rate structure goals: to achieve efficiency and simplicity as well as to ensure continuity of rates, fairness between rate classes, and corporate earnings stability. D.P.U. 17-170, at 313; D.P.U. 15-155, at 455; D.P.U. 15-80/D.P.U. 15-81, at 294; D.P.U. 13-75, at 330. 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. 14-150, at 373; 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). Below, the Department addresses the allocation of demand-related costs and the classification of distribution main costs.

#### b. Demand-Related Costs

The Company's ACOSS utilizes a PR allocator, which is based on each rate class's system monthly loads, to allocate demand-related costs, such as mains (Exh. ES-DAH-1, at 7). The Company states that this method for allocating demand-related costs has been a long-standing accepted method in Massachusetts[205] (Exh. ES-DAH-Rebuttal-1, at 5). While the PR method has been accepted in Massachusetts, the Department is not precluded from considering an appropriate alternative method for allocating demand-related costs.

The DOD-FEA proposed the use of a peak-day factor to allocate demand-related costs in the ACOSS (Exh. DOD-MPG-1, at 7-8). The peak-day factor allocation method applies a cost causation principle, which prescribes that demand-related costs are driven by the need to meet customer demand on the peak day (Exh. DOD-MPG-1, at 9-11). Further, the Company's existing tariffs support the use of a peak-day factor allocation method (Exh. DOD-MPG-1, at 10-11). For example, in NSTAR Gas's proposed Terms and Conditions (proposed M.D.P.U. No. 400E), for capacity assignment (¶ 13.3) and for peaking supply (¶ 16.6.4), the Company establishes a total capacity quantity and portion of the peaking supply that is tied to the maximum daily peak quantity. In addition, for proposed rate G-53 (proposed M.D.P.U. No. 435D), demand is based on the customer's highest actual measured maximum daily gas usage in each season.

The Department also finds that the Company is readily capable of implementing a peak-day factor allocation method for demand-related costs (RR-DPU-12(a)). Further, the record demonstrates that use of a peak-day factor allocation method would not require a rate

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205 The Company's PR allocator is based on a method developed by Gary H. Grainer of the Wisconsin Public Service Corporation, which was published in the Public Utilities Fortnightly, on November 9, 1972 (Exh. ES-DAH-1). NSTAR Gas states that, to its knowledge, Massachusetts is the only jurisdiction that uses the PR method (Exh. DOD-FEA-NSTAR 1-19(c)).

impact mitigation plan after Section 94I's rate increase and the Department's distribution rate increase constraints are applied (RR-DPU-12, Att. (b)). The appropriate distribution rate constraint is discussed below in Section XII.D. Finally, the Department rejects the Company's argument that customers taking service under the rate class G-53 can absorb an undue cross-class subsidization because these customers often can pass on their costs to their customers. The ability to pass on overhead costs is not a criterion used by the Department for evaluation of rate structure, and, even if it were, there is no evidence on the record to support this argument.

Based on all of the above considerations, the Department finds that the use of a peak-day factor is an appropriate method to allocate demand-related costs in the ACOSS, as it more accurately reflects how the Company incurs its demand-related costs. Accordingly, the Company is directed to use a peak-day factor to allocate demand-related costs.

c. Cost Classification – Distribution Mains

The Company's ACOSS classifies its distribution mains costs as a demand-related cost (Exh. DAH-2, Sch. 3). The DOD-FEA proposed an alternative method which classifies distribution main costs as both a customer- and demand-related costs (Exh. DOD-MPG-1, at 19). While it can be determined that the result of this proposal would be to allocate more costs to rate classes with a greater number of customers, the exact effect was not calculated (Exh. DOD-MPG-1, at 19). In particular, it is unclear how the costs would be weighted between customer-related costs and demand-related costs. Further, it cannot be discerned how the costs would specifically affect the rate class revenue requirements at equalized rates of return. Without the foregoing evidence, the Department cannot assess if the resulting rates provide continuity and allow customers to adjust to the changes. D.P.U. 17-170, at 315; D.P.U. 13-75, at 332; D.P.U. 12-25, at 447; D.P.U. 09-39, at 404. Thus, while the Department acknowledges that the DOD-FEA proposal may have merit, there is not sufficient evidence in this proceeding to properly implement the alternative method of classifying distribution mains costs. Accordingly, the Company is directed to continue to classify its distribution mains costs as a demand-related cost.

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. 14-150, at 374; D.P.U. 11-01/D.P.U. 11-02, at 438; D.P.U. 10-55, at 524; D.P.U. 09-30, at 377; D.P.U. 08-35, at 227; D.T.E. 03-40, at 372. 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. 14-150, at 374; D.P.U. 11-01/D.P.U. 11-02, at 438; D.P.U. 10-55, at 524; D.P.U. 09-30, at 377-378; D.P.U. 08-35, at 227; D.P.U. 07-71, at 159.

For the marginal cost study, the Company uses data from Annual Returns to the Department for 1984 through 2018 (Exh. ES-MFB-1, at 4). The Company states that, consistent with Department precedent, the marginal cost study was limited to the estimation of capacity-related distribution costs (Exh. ES-MFB-1, at 4,8-9). Specifically, the Company estimated the marginal cost of capacity-related distribution plant, marginal capacity-related operations expense, marginal capacity-related maintenance expense, and three ancillary components: (1) marginal general plant; (2) marginal administrative and general expense; and (3) marginal materials and supplies expense (Exh. ES-MFB-1, at 4, 9).

In preparing the marginal cost study, the Company collected various plant, expense, and customer data from the Company's annual reports to the Department (Exh. ES-MFB-1, at 3, 5). From this data, the Company created four types of new data series by: (1) transforming expense data to remove price inflation; (2) separating distribution O&M expenses into capacity- or customer-related expenses; (3) normalizing peak demands; and (4) developing four subsets of measures to reflect the nature and condition of the distribution system (Exh. ES-MFB-1, at 5-6). Further, the Company created and used several additional data series in the regression analyses to measure the annual change in normalized peak day demand that would explain the Company's annual capacity-related distribution plant additions (Exh. ES-MFB-1, at 6-7).

The regression analyses presented by the Company contain a variety of independent explanatory variables (Exhs. ES-MFB-1, at 6-8; ES-MFB-2 (Rev. 1)). Included among them are several dummy variables that represent various stages in the Company's history (Exh. ES-MFB-2 (Rev. 1)). Additionally, the Company used dummy variables to explain behavior not explained by the data alone (Exh. ES-MFB-2 (Rev. 1)).

The Company calculated the distribution plant fixed carrying charge rate, which is 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. ES-MFB-1, at 12-13; ES-MFB-2 (Rev. 1)). The Company used a version of the fixed carrying charge calculation known as the "economist's fixed carrying charge rate," stating that it accounts for the reduced value of the revenue requirements in future years due to price inflation (Exh. ES-MFB-1, at 12).

The Company estimated the total loss-adjusted marginal distribution cost of service to be $198.78 per decatherm ("Dth") of demand (Exh. ES-MFB-2 (Rev. 1), Sch. 5 at 1). These estimates incorporate lost and unaccounted for gas (Exh. ES-MFB-2 (Rev. 1), Sch. 5 at 2-3). Based on these estimates, the Company developed class-specific marginal cost rates per Dth of sendout (Exhs. ES-MFB-1 at 13; ES-MFB-2, Sch. 5 at 2-3).

2. Positions of the Parties

The Company maintains that the Department has stated that a marginal cost study should: (1) include sufficient detail to allow a full understanding of the methods used to determine the marginal cost estimates; (2) use appropriate historical data that is reliable; (3) be based on proper econometric techniques to provide statistically reliable estimates; (4) be based on multi-variate regression techniques; (5) include the results of appropriate diagnostic tests to ensure the appropriateness of the regressions in the marginal cost study; and (6) not include estimates of marginal production, transmission or customer costs. (Company Brief, at 401, citing D.P.U. 13-75, at 336-337). The Company asserts that its marginal cost study is consistent with these Department directives and standards (Company Brief, at 402-403). No other party commented on this issue on brief.

3. Analysis and Findings

Our review of the Company's marginal cost study indicates that the study incorporates sufficient detail to allow a full understanding of the methods used to determine the marginal cost estimates. As an initial matter, the Company has excluded from the marginal cost study all production, transmission, and customer costs; and, instead, the Company confined the marginal cost study to the estimation of capacity-related distribution costs (Exhs. ES-MFB-1, at 2, 4, 9-10; ES-MFB-2 (Rev. 1)). This method is consistent with Department precedent. D.T.E. 03-40, at 377.

Further, we find that the Company used appropriate historical data that are reliable in developing the marginal cost study, as required by Department precedent (Exh. ES-MFB-1, at 3-4, 11). D.P.U. 14-150, at 378. Consistent with previous Department directives regarding time series, the Company used over 30 years of historical data for its marginal cost study, using data encompassing the period 1984 through 2018 (Exh. ES-MFB-1, at 4). D.P.U. 14-150, at 378; D.P.U. 10-55, at 531; D.T.E. 02-24/25, at 243-245.

Our review of the econometric analyses used by the Company to calculate the marginal distribution capacity-related costs indicates that the Company has sufficiently documented its method of estimation (Exh. ES-MFB-2 (Rev. 1)). Additionally, the Company has applied proven econometric techniques (Exh. ES-MFB-2 (Rev. 1)). Therefore, the Department accepts the Company's marginal costs estimated from the econometric analyses.

The Department also finds that the Company used multi-variate regression techniques and performed appropriate diagnostic tests to ensure the appropriateness of the regressions in the marginal cost study (Exhs. ES-MFB-1, at 7-8; ES-MFB-2 (Rev. 1)). The Department has reviewed the dummy variables used in the study, as well as the results of the analyses performed without the inclusion of dummy variables (Exh. ES-MFB-2 (Rev. 1)). The Department finds that the Company has adequately demonstrated that the use of dummy variables in performing the marginal cost study does not unreasonably alter the statistical significance of the results of the regression analyses to render the results unacceptable.

Based on the foregoing, we conclude that the marginal cost study provided by the Company is consistent with Department precedent. Accordingly, we accept the Company's marginal costs as outlined above.

D. Class Revenue Allocation

1. Introduction

The Company's proposed base distribution revenue is $233,080,833 (Exh. ES-RDC-2 (Rev.1), Sch. 1).[206] To calculate class revenue targets to recover the proposed base distribution revenue, the Company first proposed to set the class revenue targets at equal rates of return using its proposed return of 7.68 percent and the results of its ACOSS (Exhs. ES-RDC-1, at 18; ES-RDC-2 (Rev.1), Sch. 1; ES-DAH-2 (Rev.1), Sch. 1). Next, the Company assured that no rate class would receive a ten percent or greater total revenue increase by allocating the total revenues that exceeded the ten-percent cap to those rate classes with room under the cap (Exhs. ES-RDC-1, at 18, 21; ES-RDC-2 (Rev.1),

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[206] The Company subsequently updated its base distribution revenue on September 1, 2020; however, an updated ACOSS and rate design exhibits were not provided.

Sch. 1). This step revealed that at equal rates of return, rate classes R-1/R-2, G-42, and G-53 exceeded the ten percent cap (Exh. ES-RDC-2 (Rev.1), Sch. 1). The Company allocated the total revenues over the cap to the rate classes that had room under the cap based on their proportional revenue requirements at equalized rates of return. Next, the Company applied a second test to assure that no rate class would receive an increase to its base distribution revenues that exceeds 150 percent of the average distribution increase across all rate classes (Exh. ES-RDC-1, at 21). The Company's proposed average distribution revenue increase across all rate classes is 18.6 percent, so an increase to a rate class's base distribution revenues over 27.9 percent was reallocated to those rates classes under the 27.9-percent cap, as well as under the ten-percent cap, using the proportional revenue requirements at equalized rates of return (Exh. ES-RDC-2 (Rev.1), Sch. 1). This step revealed that rate classes G-42, G-43, G-52, and G-53 exceeded the 150 percent cap, and, therefore, had revenues exceeding the cap reallocated to rate classes R-3/R-4, G-41, and G-51 to assure that neither of the caps were exceeded (Exh. ES-RDC-2 (Rev.1), Sch. 1). NSTAR Gas and the Attorney General agreed that the Company's proposal would be revised to include a 175-percent cap rather than a 150-percent cap on the average distribution increase across all rate classes (ES-AG Stipulations at 5). As a result, the revenue requirement assigned to rate G-43 no longer exceeded the distribution revenue cap, and the amount of revenues exceeding the distribution revenue cap for rates G-42, G-52 and G-53 were lower, thereby reducing the revenues reallocated to rate classes R-3/R-4, G-41, G-43 and G-51 by $1,806,423. (Exh. ES-RDC-2 (Rev.1), Sch. 1).

2. Positions of the Parties

a. DOD-FEA

The DOD-FEA argues that the Company's proposed revenue requirements, after applying the rate constraints, do not move the rate classes, specifically the residential rate classes, toward cost of service (DOD-FEA Brief at 25-26). Thus, the DOD-FEA, endorses for each rate class a distribution rate increase, a cap of 150 percent of the system average increase, if the Department approves the use of a peak-day factor to allocate demand-related costs (DOD-FEA Brief at 26). The DOD-FEA contends that that this cap to the rate classes' distribution revenue increases will provide a gradual and balanced move toward cost of service (DOD-FEA Brief at 26-27).

b. TEC

TEC argues that if the Department were to order the use of the peak-day factor allocation method, it should set for each rate class a distribution rate increase cap of 200 percent of the system average increase (TEC Brief at 6, citing RR-DPU-12). TEC contends that a 175-percent cap using the peak-day factor allocation method would apportion revenues from the commercial class G-42 to the residential heating class, whereas a cap at 200 percent would not result in any such apportionment (TEC Brief at 6, citing RR-DPU-12, Atts. (b), (c)).

c. Company

NSTAR Gas contends that TEC's recommendation to implement for each rate class a distribution rate increase cap of 200 percent of the system average increase ignores the agreement reached by the Company and the Attorney General (Company Reply Brief at 75, citing ES-AG Stipulations at 5). The Company notes that it agreed to apply a distribution rate increase cap of 175 percent in order to address the Attorney General's concerns to protect both residential customers and large service customers, such as those customers in rate G-53 (Company Reply Brief at 75, citing RR-DPU-12, at 2). According to the Company, any attempts to amend the agreement at this late stage of the proceeding would be unfair and would risk unraveling the entire agreement (Company Reply Brief at 75-76).

3. Analysis and Findings

In the Company's initial filing, it proposed for each rate class a distribution rate increase cap of 150 percent of the system average increase (Exh. ES-RDC-1, at 21). On June 3, 2020, the Company and the Attorney General agreed to increase this cap to 175 percent of the system average increase (ES-AG Stipulations at 5). The stipulated 175-percent distribution rate increase cap was a compromise with the Attorney General who originally proposed a 200-percent cap (Exh. AG-SJR-1, at 4, 14-18). Subsequently, the Company provided illustrative revenue requirements by rate class using a peak-day factor to allocate demand costs (RR-DPU-12 & Atts.). In doing so, the Company noted that if the Department were to adopt a peak-day factor allocation method for demand-related costs, the Department also should apply a 200-percent distribution rate increase cap (and not the agreed-upon 175-percent cap) for each rate class (RR-DPU-12, at 2). The Attorney General did not comment on the Company's illustrative revenue requirements or its recommended application of a 200-percent distribution rate increase cap under the peak-day factor allocation scenario.

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. As noted above, the Department has adopted the peak-day factor allocation method for demand-related costs. The record shows that using the peak-day factor allocation method along with a distribution rate increase cap of 175 percent of the system average increase would result in a reallocation of revenues from the rate class G-42 to the residential heating class (RR-DPU-12 & Atts.). Application of a 200-percent distribution rate increase cap, however, will ensure less revenue is reallocated from the G-42 rate class to the other rate classes (i.e., rate classes R-3/R-4, G-41, G-43, G-52, and G-53) that did not exceed other rate constraints (i.e., the Section 94I-cap and/or the Department's directive herein that no rate class shall receive a rate decrease) (RR-DPU-12 & Atts.; see also Schedule 10). Thus, we are persuaded that a distribution rate increase cap of 200 percent of the system average increase strikes the appropriate balance between the Department's rate design goal of rate continuity and principles of cost causation (RR-DPU-12 & Atts.). D.P.U. 17-170, at 343; D.P.U. 13-75, at 362-363. More specifically, application of a 200-percent distribution rate increase cap moves rates closer to cost causation while still providing rate continuity in distribution rates for rate class G-42. Further, given that the Attorney General originally proposed a 200-percent distribution rate increase cap (Exh. AG-SJR-1, at 4, 14-18) and did not address this issue on brief, we conclude that adopting the 200-percent cap does not adversely impact the agreement reached between the Attorney General and the Company, particularly with respect to the host of other agreed-upon issues.

In addition to a distribution rate increase cap, which now will be set at 200 percent of the system average increase, the Company also will apply the Section 94I-cap, which provides that no rate class shall receive a rate increase greater than ten percent (Exh. ES-RDC-1, at 18-19). We find, however, that additional rate constraints are appropriate. Based on our review of the record, the Department finds that at least one rate class (i.e., rate class G-51) would experience a rate decrease after the rate design parameters set forth above are applied to the rate class revenue requirements at equalized rates of return, while other rate classes would experience a rate increase and would be allocated a revenue requirement that exceeds the rate class revenue requirements at equalized rates of return (RR-DPU-12, at 3 & Atts.). In order to address this disparity and mitigate the increases to these rate classes, we find that it is appropriate for the Company to further allocate the revenue increase approved in this Order so that no rate class receives a rate decrease. Boston Gas Company and Colonial Gas Company d/b/a National Grid, D.P.U. 17-170, at 342; Fitchburg Gas and Electric Light Company d/b/a Unitil, D.P.U. 11-01/D.P.U. 11-02, at 478 (2011); D.T.E. 01-56, at 139. Accordingly, as shown in Schedule 10 attached to this Order, the Department directs the Company to reallocate any revenue requirement credit below the rate floor (i.e., the point where a rate class would receive a rate decrease) to the other rate classes based on their proportional revenue requirement at equalized rates of return, excluding any rate classes that already benefit from the ten-percent cap.

E. Low-Income Discount

1. Introduction

In D.P.U. 14-150, at 402, the Department approved the Company's current low-income discount rate of 25 percent. The Company did not propose a change to its low-income discount rate in its initial filing (proposed M.D.P.U. Nos. 421G, 423G, Low Income Discount Adjustment). During the proceeding, the Low-Income Network requested that the Company restate its proposed bill impacts based on a low-income discount rate of 36 percent, as approved for NSTAR Electric in D.P.U. 17-05-B at 158 (Exhs. LI-ES 2-1; LI-ES 2-2). In response to the Low-Income Network's request, the Company assessed the bill impacts resulting from a 36-percent low-income discount rate and found that low-income customers would receive a bill decrease compared to current rates, even with the allowance of the full rate increase requested by the Company in the instant proceeding (Exhs. LI-ES 2-1 & Att.; LI-ES 2-2). Thus, the Company proposed a low-income discount rate of 30 percent (Exh. LI-ES 2-2). The Company states that implementing a 30 percent discount, instead of the current 25 percent amount, will decrease the bill impact on low-income customers and, under the proposed rates, this change would increase other rate classes' bill impacts by less than one percent (Exh. LI-ES 2-2). On July 24, 2020, the Company and the Low-Income Network agreed to a low-income discount rate of 30 percent (ES-LI Stipulation at 2-3).

2. Positions of the Parties

a. Low Income Network

The Low-Income Network argues that, even prior to the COVID-19 pandemic, low-income customers found it increasingly difficult to afford their energy bills because of both increasing energy costs and decreasing incomes (Low-Income Network Brief at 1-2). Further, the Low-Income Network notes that the Department has recognized that the COVID-19 pandemic has caused unprecedented unemployment, lost income, lost health insurance coverage, and increased household expenses (Low-Income Network Brief at 3, citing Policies and Practices for Electric and Gas Companies Regarding Customer Assistance and Ratemaking Measures in Connection to the State of Emergency Regarding the Novel Coronavirus (COVID-19) Pandemic, D.P.U. 20-58, Vote and Order Opening Inquiry at 2-3 (May 11, 2020)). The Low-Income Network asserts that the agreed upon low-income discount rate of 30 percent assists low-income customers and minimizes the impact to all other customers (Low-Income Network Brief at 3, citing Exh. LI-ES 2-2). Finally, the Low-Income Network notes that the 30-percent discount rate was not determined by statue but was driven by bill impacts (Low-Income Network Brief at 3-4, citing Tr. 4 at 573-575, 576-577).

b. Company

NSTAR Gas notes that, during the proceeding, the Company and the Low-Income Network entered into discussions about the low-income discount with the objective of balancing the difficulty of low-income customers to afford heating bill increases with the economic conditions brought on by the COVID-19 pandemic (Company Brief at 411). The Company asserts that the agreed-upon increase of the low-income discount to 30 percent avoids greater bill increases to low-income customers than observed in prior rate cases and balances the rate impact to remaining customers (Company Brief at 411, citing Tr. 4, at 577).

3. Analysis and Findings

In determining whether an increase to the low-income discount is warranted, the Department must consider and balance the rate structure goals of fairness and continuity. D.P.U. 10-55, at 535; D.T.E. 03-40, at 365; D.T.E. 01-56, at 134; D.T.E. 01-50, at 28; D.P.U. 96-50 (Phase I) at 133. Thus, although the Company and Low-Income Network have agreed to an increase in the low-income discount, the Department must fully consider and weigh both the benefits to low-income customers and the change in costs to remaining customers.

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. Expanding Low Income Consumer Protections and Assistance, D.P.U. 08-4, at 36 (2008). The Company's current low-income discount of 25 percent already provides a discount level beyond that required by Section 1F, as the discount levels in effect in March 1, 1998 for R-2 and R-4 rate classes were 18.8 percent and 18.4 percent, respectively. D.P.U. 14-150, at 401-402. Therefore, low-income customers already benefit from a discount that is greater than that required by statute.

Further, although the Company and Low-Income Network raise legitimate concerns regarding the current adverse economic impact of the COVID-19 pandemic on the

Commonwealth and the difficulties faced by its residents, the base distribution rates set in this proceeding are intended to be in effect for the next ten years, consistent with the PBR term approved in Section V.B.4, above. As such, we must remain mindful of the long-term impact of allocating additional rate increases to non-low-income discount customers over the term of the PBR plan (i.e., the recovery of revenues associated with the low-income discount).

Based on these considerations, we are not persuaded that an increase in the low-income discount to 30 percent is warranted. See Fitchburg Gas and Electric Light Company, D.P.U. 19-131, at 13-14 (February 28, 2020) (the Department is not convinced that an adjustment to the low-income discount for electric customers inevitably would warrant a corresponding adjustment to the low-income discount for gas customers). Rather, we find that maintaining the current low-income discount of 25 percent provides an appropriate level of rate relief to low-income customers while minimizing the rate impact on the remaining rate classes. Thus, we conclude that the Department's rate design goals of fairness and continuity are best served by maintaining the current low-income discount of 25 percent.

Finally, the Department recognizes that recent adjustments to the low-income discount have been approved for electric distribution companies to comply with the provisions of G.L. c. 164, § 141 ("Section 141") regarding the scale of on-site generation and its impact on affordability for low-income customers.[207] D.P.U. 18-150, at 519; D.P.U. 17-05-B

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[207] Section 141 provides:

at 158; D.P.U. 15-155, at 470. Section 141 allows for an adjustment to the low-income discount offered by electric distribution companies to compensate for increasing program costs collected outside of base distribution rates. In an effort to meet the spirit of Section 141, going forward the Department will consider adjusting the low-income discount rate for local gas distribution companies if the records shows that analogous program costs collected from all natural gas ratepayers are of such scale that those costs have impacted affordability for low-income customers.

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 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 its gas use is high, medium, or low. The rate design for each rate class is discussed below.

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> In all decisions or actions regarding rate designs, the [D]epartment shall consider the impacts of such actions, including the impact of new financial incentives on the successful development of energy efficiency and on-site generation. Where the scale of on-site generation would have an impact on affordability for low-income customers, a fully compensating adjustment shall be made to the low-income rate discount.

2. Rates R-1 (Residential Non-Heating) and R-2 (Low-Income Non-Heating)

a. Introduction

Rate R-1 is available to residential customers whose gas use is for fireplaces, cooking, and similar purposes, but not for gas space heating equipment (Exhs. ES-RDC-1, at 32; ES-RDC/LMC-2 (Rev.) at 151 (proposed M.D.P.U. No. 420D)). Rate R-2 is a subsidized rate that is available at single locations for domestic non-heating purposes in private dwellings and individual apartments (Exh. ES-RDC/LMC-2 (Rev.) at 154 (proposed M.D.P.U. No. 421G)). A customer will be eligible for this rate upon verification of the customer's receipt of any means-tested public benefit program or verification of the eligibility 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 (Exh. ES-RDC/LMC-2 (Rev.) at 154 (proposed M.D.P.U. No. 421G)). As discussed in Section XII.E.3 above, the Department approved a 25-percent discount off the total bill for customers taking service on Rate R-2. The Company's current R-1 and R-2 customer charge is $8.50 per month (Exh. ES-RDC-1, at 26). NSTAR Gas proposed a customer charge of $9.75 per month for rate classes R-1 and R-2 (Exhs. ES-RDC-1, at 26; ES-RDC/LMC-2 (Rev.) at 151 (proposed M.D.P.U. No. 420D); ES-RDC/LMC-2 (Rev.) at 153 (proposed M.D.P.U. No. 421G)). Based on its May 15, 2020 update, the Company proposed to collect the remainder of the rate class revenue requirement through a $0.6431 per therm charge (Exh. ES-RDC-2 (Rev.), Sch. 9, at 1).

b. Analysis and Findings

According to the Company's ACOSS, the existing embedded customer charge for rate classes R-1 and R-2 is $20.32 per month (Exh. ES-DAH-2 (Rev.), Sch. 1, at 4). Based on a review of embedded costs and the bill impacts on customers, the Department finds that a monthly customer charge of $9.75 for rate classes R-1 and R-2 best meets our rate design goals and objectives. The Company shall set the volumetric rate for rate classes R-1 and R-2 to recover the remaining class revenue requirement approved in this Order.[208]

3. Rates R-3 (Residential Heating) and R-4 (Low-Income Heating)

a. Introduction

Rate R-3 is available to residential customers whose primary means of heating in their home is gas (Exhs. ES-RDC-1, at 33; ES-RDC/LMC-2 (Rev.) at 156 (proposed M.D.P.U. No. 422D)). Rate R-4 is a subsidized rate that is available at single locations for domestic heating purposes in private dwellings and individual apartments (Exh. ES-RDC/LMC-2 (Rev.) at 158 (proposed M.D.P.U. No. 423G)). A customer will be eligible for this rate upon verification of the customer's receipt of any means-tested public benefit program or verification of the eligibility 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 (Exh. ES-RDC/LMC-2 (Rev.) at 158 (proposed M.D.P.U. No. 423G)). As

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208 The calculation of all volumetric per therm delivery charges shall be truncated after the fourth decimal place.

discussed in Section XII.E.3 above, the Department approved a 25-percent discount off the total bill for customers taking service on Rate R-4. The Company's current R-3 and R-4 customer charge is $8.50 per month (Exh. ES-RDC-1, at 26). NSTAR Gas proposed customer charge of $10.00 per month for rate classes R-3 and R-4 (Exhs. ES-RDC-1, at 26; ES-RDC/LMC-2 (Rev.) at 156 (proposed M.D.P.U. No. 422); ES-RDC/LMC-2 (Rev.) at 158 (proposed M.D.P.U. No. 423G)). Based on its May 15, 2020 update, the Company proposes to collect the remainder of the rate class revenue requirement through a $0.5260 per therm charge (Exh. ES-RDC-2 (Rev.), Sch. 9, at 1).

b. Analysis and Findings

According to the Company's ACOSS, the existing embedded customer charge for rate classes R-3 and R-4 is $30.12 per month (Exh. ES-DAH-2 (Rev.), Sch. 1, at 4). Based on a review of embedded costs and the bill impacts on customers, the Department finds that a monthly customer charge of $10.00 for rate classes R-3 and R-4 best meets our rate design goals and objectives. The Company shall set the volumetric rate for rate classes R-3 and R-4 to recover the remaining class revenue requirement approved in this Order.

4. Rate G-41 (Low Load Factor General Service - Small)

a. Introduction

Rate G-41 is available to non-domestic customers consuming less than 10,000 therms per year and whose consumption from May through October is less than 30 percent of total consumption through the same calendar year (Exh. ES-RDC/LMC-2 (Rev.) at 160 (proposed M.D.P.U. No. 430D)). The Company proposed to increase the monthly customer charge assessed to Rate G-41 customers from the current charge of $19.00 to $21.00

(Exhs. ES-RDC-1, at 26; ES-RDC/LMC-2 (Rev.) at 160 (proposed M.D.P.U. No. 430D)). Based on its May 15, 2020 update, the Company proposed to collect the remainder of the rate class revenue requirement through a $0.3103 per therm charge (Exh. ES-RDC-2 (Rev.), Sch. 9, at 1).

b. Analysis and Findings

According to the Company's ACOSS, the existing embedded customer charge for Rate G-41 is $30.39 per month (Exh. ES-DAH-2 (Rev.), Sch. 1, at 4). Based on a review of embedded costs and the bill impacts on customers, the Department finds that a monthly customer charge of $21.00 for Rate G-41 best meets our rate design goals and objectives. The Company shall set the volumetric rate for Rate G-41 to recover the remaining class revenue requirement approved in this Order.

5. Rate G-42 (Low Load Factor General Service - Medium)

a. Introduction

Rate G-42 is available to non-domestic customers consuming at least 10,000 therms but less than 100,000 therms per year and whose consumption from May through October is less than 30 percent of total consumption through the same calendar year (Exh. ES-RDC/LMC-2 (Rev.) at 162 (proposed M.D.P.U. No. 431D)). The Company proposed to increase the monthly customer charge assessed to Rate G-42 customers from the current charge of $40.00 to $46.00 (Exhs. ES-RDC-1, at 26; ES-RDC/LMC-2 (Rev.), at 162 (proposed M.D.P.U. No. 431D)). The Company proposed employing seasonal distribution rates; however, the rates generated by the ACOSS resulted in higher off-peak rates than peak rates (Exh. ES-RDC-1, at 29). Since this rate design would not send an economic signal that would encourage demand response behavior, the Company proposed to maintain its current peak to off-peak relationship (Exh. ES-RDC-1, at 29). Based on its May 15, 2020 update, the Company proposed to collect the remainder of the rate class revenue requirement through a seasonal peak charge of $0.2975 per therm and an off-peak charge of $0.2038 per therm (Exh. ES-RDC-2 (Rev.), Sch. 9, at 1).

b. Analysis and Findings

According to the Company's ACOSS, the existing embedded customer charge for Rate G-42 is $201.40 per month (Exh. ES-DAH-2 (Rev.), Sch. 1, at 4). Based on a review of embedded costs and the bill impacts on customers, the Department finds that a monthly customer charge of $46.00 for Rate G-42 best meets our rate design goals and objectives. The Company shall set the volumetric seasonal rates for G-42 to maintain the ratio of peak to off-peak revenue requirement proposed by the Company and at a level to recover the remaining class revenue requirement approved in this Order.

6. Rate G-43 (Low Load Factor General Service - Large)

a. Introduction

Rate G-43 is available to non-domestic customers consuming greater than 100,000 therms per year and whose consumption from May through October is less than 30 percent of total consumption through the same calendar year (Exh. ES-RDC/LMC-2 (Rev.) at 164 (proposed M.D.P.U. No. 432D)). The Company proposed to increase the monthly customer charge assessed to Rate G-43 customers from the current charge of $141.00 to $181.00 (Exhs. ES-RDC-1, at 26; ES-RDC/LMC-2 (Rev.), at 164 (proposed M.D.P.U. No. 432D)). The Company proposed employing seasonal distribution rates, allocated by the results of the ACOSS (Exh. ES-RDC-1, at 29). Based on its May 15, 2020 update, the Company proposed to collect the remainder of the rate class revenue requirement through a seasonal peak charge of $0.2718 per therm and an off-peak charge of $0.1518 per therm (Exh. ES-RDC-2 (Rev.), Sch. 9, at 2).

b. Analysis and Findings

According to the Company's ACOSS, the existing embedded customer charge for Rate G-43 is $507.07 per month (Exh. ES-DAH-2 (Rev.), Sch. 1, at 4). Based on a review of embedded costs and the bill impacts on customers, the Department finds that a monthly customer charge of $181.00 for Rate G-43 best meets our rate design goals and objectives. The Company shall set the volumetric seasonal rates for G-43 to maintain the ratio of peak to off-peak revenue requirement proposed by the Company and at a level to recover the remaining class revenue requirement approved in this Order.

7. Rate G-51 (High Load Factor General Service - Small)

a. Introduction

Rate G-51 is available to non-domestic customers consuming less than 10,000 therms per year and whose consumption from May through October is greater than 30 percent of total consumption through the same calendar year (Exh. ES-RDC/LMC-2 (Rev.) at 166 (proposed M.D.P.U. No. 433D)). The Company proposed to increase the monthly customer charge assessed to Rate G-51 customers from the current charge of $19.00 to $21.00 (Exhs. ES-RDC-1, at 26; ES-RDC/LMC-2 (Rev.) at 166 (proposed M.D.P.U. No. 433D)). Based on its May 15, 2020 update, the Company proposed to collect the remainder of the rate class revenue requirement through a seasonal peak charge of $0.3003 per therm and an off-peak charge of $0.1841 per therm (Exh. ES-RDC-2 (Rev.), Sch. 9, at 2).

b. Analysis and Findings

According to the Company's ACOSS, the existing embedded customer charge for Rate G-51 is $32.42 per month (Exh. ES-DAH-2 (Rev.), Sch. 1, at 4). Based on a review of embedded costs and the bill impacts on customers, the Department finds that a monthly customer charge of $21.00 for Rate G-51 best meets our rate design goals and objectives. The Company shall set the volumetric seasonal rates for G-51 to maintain the ratio of peak to off-peak revenue requirement proposed by the Company and at a level to recover the remaining class revenue requirement approved in this Order.

8. Rate G-52 (High Load Factor General Service - Medium)

a. Introduction

Rate G-52 is available to non-domestic customers consuming at least 10,000 therms but less than 100,000 therms per year and whose consumption from May through October is greater than 30 percent of total consumption through the same calendar year (Exh. ES-RDC/LMC-2 (Rev.) at 168 (proposed M.D.P.U. No. 434D)). The Company proposed to increase the monthly customer charge assessed to Rate G-52 customers from the current charge of $40.00 to $46.00 (Exhs. ES-RDC-1, at 26; ES-RDC/LMC-2 (Rev.) at 168 (proposed M.D.P.U. No. 434D)). The Company proposed employing seasonal distribution rates; however, the rates generated by the ACOSS resulted in higher off-peak rates than peak rates (Exh. ES-RDC-1, at 29). Since this rate design would not send an economic signal that would encourage demand response behavior, the Company proposed to maintain its current peak to off-peak relationship (Exh. ES-RDC-1, at 29). Based on its May 15, 2020 update, the Company proposed to collect the remainder of the rate class revenue requirement through a seasonal peak charge of $0.2801 per therm and an off-peak charge of $0.1781 per therm (Exh. ES-RDC-2 (Rev. 1), Sch. 9, at 2).

b. Analysis and Findings

According to the Company's ACOSS, the existing embedded customer charge for Rate G-52 is $174.13 per month (Exh. ES-DAH-2 (Rev. 1), Sch. 1, at 4). Based on a review of embedded costs and the bill impacts on customers, the Department finds that a monthly customer charge of $46.00 for Rate G-52 best meets our rate design goals and objectives. The Company shall set the volumetric seasonal rates for G-52 to maintain the percentage of peak to off-peak revenue requirement ratio proposed by the Company and at a level to recover the remaining class revenue requirement approved in this Order.

9. Rate G-53 (High Load Factor General Service - Large)

a. Introduction

Rate G-53 is available to non-domestic customers consuming greater than 100,000 therms per year and whose consumption from May through October is greater than 30 percent of total consumption through the same calendar year (Exh. ES-RDC/LMC-2, at 170 (proposed M.D.P.U. No. 435D)). The Company proposed to increase the monthly customer charge assessed to Rate G-53 customers from the current charge of $237.00 to $305.00 (Exhs. ES-RDC-1, at 26; ES-RDC/LMC-2, at 170 (proposed M.D.P.U. No. 435D). The Company proposed employing seasonal distribution rates, allocated by the results of the ACOSS (Exh. ES-RDC-1, at 29). Based on its May 15, 2020 update, the Company proposed to collect the remainder of the rate class revenue requirement through a seasonal peak $3.81 per maximum daily transportation quantity ("MDTQ") demand charge and an off-peak $1.98 per MDTQ demand charge (Exh. ES-RDC-2 (Rev. 1), Sch. 9, at 2).

b. Analysis and Findings

According to the Company's ACOSS, the existing embedded customer charge for Rate G-53 is $640.26 per month (Exh. ES-DAH-2 (Rev. 1), Sch. 1, at 4). Based on a review of embedded costs and the bill impacts on customers, the Department finds that a monthly customer charge of $305.00 for Rate G-53 best meets our rate design goals and objectives. The Company shall set the volumetric seasonal rates[209] for G-53 to maintain the percentage of peak to off-peak revenue requirement ratio proposed by the Company and at a level to recover the remaining class revenue requirement approved in this Order.[210]

## XIII. CUSTOMER CONNECTION SURCHARGE

### A. Company's Proposal

The Company proposed a new customer connection rider tariff ("New Customer Surcharge"), which will apply a surcharge to customers that request service on or after November 1, 2021. The Company intends to use the new surcharge to support a fund that the Company plans to distribute to reduce the upfront financial barriers for certain new customer connections (proposed M.D.P.U. No. 453; Exh. ES-DPH/ANB-1, at 153-154,

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209 The calculation of all volumetric per MDTQ delivery charges shall be truncated after the second decimal place.

210 In Section XII.B.3, the Department considered and approved an adjustment to the Company's ACOSS, specifically the demand factor used.

162-163). The Company states that it developed this proposal to address the decline in customer additions due to on-main saturation and the current cost of connection (proposed M.D.P.U. No. 453; Exhs. ES-DPH/ANB-1, at 152-154; DPU-ES 14-5; Tr. 4, at 531). NSTAR Gas contends that the proposed tariff is consistent with St. 2014, c. 149, § 3 ("Section 3"), which authorizes programs that address the availability, affordability, and feasibility of natural gas service, because the New Customer Surcharge will assist new customers with their connection costs and reduce fixed costs borne by existing customers (Exh. ES-DPH/ANB-1).

Per NSTAR Gas's proposal, a monthly surcharge will be applied for a period of twenty years from the date service is initiated to customer bills for new premises[211] assigned to retail rate schedules for delivery service (proposed M.D.P.U. No. 453 (Applicability)(Terms)).[212] The Company proposed to set the surcharge for Rate G-53 customers equal to ten percent of the customer's applicable delivery charges (proposed M.D.P.U. No. 453 (Charge Per Month)). For all other customers, NSTAR Gas proposed that the surcharge be 30 percent of the customer's applicable delivery charges (proposed M.D.P.U. No. 453 (Charge Per Month)). However, customers taking service under Rates

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211 New premises are defined as the residence or general service facility receiving natural gas service where natural gas service was unavailable prior to the request by the customer (proposed M.D.P.U. No. 453 (Applicability)).

212 The surcharge will run with the premises, to be paid by the customer of record from time to time, provided that the customer of record is not taking service under Rate R-2 or Rate R-4, for a total duration of twenty years regardless of the customer of record (Exh.DPU-ES-14-30).

R-2 (low income residential heating) and R-4 (low income residential heating) are exempt from the provisions of the proposed tariff (proposed M.D.P.U. No. 453 (Applicability)).

Currently, NSTAR Gas is required to collect contributions in aid of construction ("CIACs") from new customers when the interconnection cost exceeds the project's life-cycle revenues (Exh. ES-DPH/ANB-1, at 153, 158). Under the proposal, New Customer Surcharge revenues would be used to reduce or eliminate the required CIAC for service requests that meet certain designated criteria, including financial, economic, environmental, societal, and operational factors (Exh. ES-DPH/ANB-1, at 153, 158; DPU-ES 14-12, Att.). The Company provided that the designated criteria will be used to assist in identifying customer connections that would benefit both the distribution system and the customer (Exh. ES-DPH/ANB-1, at 158). NSTAR Gas explained that an internal governance committee will evaluate service requests based on the designated criteria and determine the most judicious use of New Customer Surcharge revenues (Exh. ES-DPH/ANB-1, at 163).[213]

Furthermore, the Company proposed to evaluate the economics of connecting new customers for inclusion into rate base in subsequent rate cases from a portfolio perspective (i.e., group of customers) rather than on an individual basis (Exh. ES-DPH/ANB-1, at 163-164). Thus, the Company proposed to demonstrate that the internal rate of return ("IRR") for the entire new customer group exceeded the rate of return ("ROR") threshold set

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[213] The governance committee would include a representative from each of the Gas Sales, Gas Supply, Gas Operations/Engineering, and Customer Care groups at Eversource (Exh. ES-DPH/ANB-1, at 163).

in the Company's prior base distribution rate case (Exh. ES-DPH/ANB-1, at 163-164). As a result, some customer connections may be approved that do not individually exceed the Company's IRR (Exh. ES-DPH/ANB-1, at 163). The Company stated that the portfolio perspective would allow the Company to apply excess return from certain projects to accommodate projects with returns that do not meet the threshold (Exhs. ES-DPH/ANB-1, at 164-165; DPU-ES 14-16; DPU-ES 14-18; DPU-ES 26-1).

The Company proposed to account for New Customer Surcharge revenues separately from other revenues, i.e., credited to a segregated liability account on the Company's balance sheet (Exh. ES-DPH/ANB-1, at 161). Further, the Company proposes to record all New Customer Surcharge revenues along with an accounting of its use (Exh. ES-DPH/ANB-1, at 169-170). Notably, the Company would continue to calculate and record each customer's associated CIAC cost (Exh. ES-DPH/ANB-1, at 169-170).

## B. Positions of the Parties

### 1. Attorney General

#### a. Statutory Requirements

The Attorney General contends that the Department should deny the proposed New Customer Surcharge because the proposal fails to comply with the statutory requirements of Section 3 (Attorney General Brief at 102). First, the Attorney General insists that the Company's proposal is not consistent with Section 3's purpose of increasing the affordability of natural gas service for new customers (Attorney General Brief at 102, 110-111). Specifically, the Attorney General asserts that the Company's current policy does not require a CIAC from 95 percent of new customers (Attorney General Brief at 102). Nevertheless, the Attorney General claims that most new customers would have to pay a 30-percent surcharge for 20 years—making gas service under the proposal less affordable for most new customers than under the Company's current policy (Attorney General Brief at 102, 110-111). Second, the Attorney General maintains that Section 3 restricts the use of surcharges to "financing of gas service expansion to new off-main customers" and that, under NSTAR Gas's proposal, surcharges may be used to finance the connection of new on-main customers in violation of the statute (Attorney General Brief at 102-103). Third, the Attorney General contends that the New Customer Surcharge, which is applicable to all new customers, whether on-main or off-main, is not one of the two types of surcharges authorized by Section 3, i.e., a surcharge applicable to all customers or a surcharge applicable to new off-main customers (Attorney General Brief at 103). Fourth, the Attorney General argues that the statutory prerequisites to establishing a surcharge under Section 3 have not been met, i.e., that the Company has not provided information sufficient for the Department to review either the Company's determination that a main or service extension is economically feasible or NSTAR Gas's CIAC policy and methodology (Attorney General Brief at 103).

b. Energy Policy

The Attorney General asserts that the New Customer Surcharge is inconsistent with the Commonwealth's energy policy because the New Customer Surcharge incentivizes the installation of new infrastructure designed to combust fossil fuels while the Commonwealth's energy policy is moving toward the elimination of net emissions from fossil fuels, including natural gas (Attorney General Brief at 106). Furthermore, the Attorney General argues that the proposal is inconsistent with Massachusetts law, which requires net-zero emissions by 2050, because it subsidizes investment in natural gas infrastructure and, therefore, promotes the use of fossil fuels beyond 2050 given the 35-year expected useful life of the assets (Attorney General Brief at 106-107, 111-112).

c. Use of Surcharge Revenues

The Attorney General also claims that the Company has not clearly stated how New Customer Surcharge revenues will be used (Attorney General Brief at 107). Specifically, the Attorney General asserts that it is unclear which customers would be eligible to participate in the program (Attorney General Brief at 107). Further, the Attorney General asserts that the customer eligibility criteria provided by the Company in discovery create more confusion than clarification (Attorney General Brief at 109-110).

2. Company

a. Purpose

The Company asserts new customer growth is critical to maintain the affordability of gas service because it allows the Company to spread fixed operating costs over a larger customer base (Company Brief at 261). NSTAR Gas contends that if the customer base does not continue to grow existing customers' distribution rates will increase in future rate cases to support the Company's increasing fixed operating costs and the investments necessary to maintain a safe and reliable distribution system (Company Brief at 261, 265 citing Exhs. ES-DPH/ANB-1, at 155; DPU-ES 14-5; Tr. 4, at 482, 499-501, 502-503, 538). The Company claims that the Department's current CIAC policy is an impediment to NSTAR Gas's new customer growth and argues that the New Customer Surcharge should be approved because it will reduce financial barriers to new customer growth, does not burden existing customers, and makes natural gas more affordable for all customers (Company Brief at 262, 263-264, 276, citing Exhs. ES-DPH/ANB-1, at 153; DPU-ES 14-16; DPU-ES 35-18; DPU-ES 35-22; Tr. 4, at 487-489, 499, 545, 549-550).

NSTAR Gas contends that it has proposed the application of a uniform surcharge to all new customers consistent with the Department's long-standing ratemaking approach (Company Brief at 274, citing Exhs. DPU-ES 14-25; DPU-ES 35-22; Tr. 4, at 481, 503-504, 527, 529-531). The Company argues that its proposal integrates the application of the IRR analysis and the CIAC approach, and preserves the purpose of each, which is to ensure existing customers are not economically harmed by the addition of new customers (Company Brief at 275, citing Exhs. DPU-ES 14-16; DPU-ES 35-22; Tr. 4, at 483-485).

b. Statutory Requirements

NSTAR Gas maintains that the legislative purpose of Section 3 is to increase the availability, affordability, and feasibility of natural gas service for new customers and that the law expressly recognizes the need for alternative rate mechanisms such as the New Customer Surcharge to effectuate that purpose (Company Brief at 266, citing St. 2014, c. 149, § 3). The Company avers that Section 3 authorizes a broad range of approaches, including surcharges to aid in the financing of gas service expansion, so long as the program ultimately approved by the Department does not "unreasonably burden existing natural gas customers" (Company Brief at 266, citing St. 2014, c. 149, § 3).

The Company argues that the New Customer Surcharge is consistent with Section 3's purpose of increasing the affordability of natural gas because the objectives of the proposal are to make gas service available to customers that cannot feasibly convert to gas service because of the financial barrier imposed by the current CIAC policy and to share the fixed costs of the distribution system amongst a larger customer base (Company Brief at 280, citing St. 2014, c. 149, § 3). Accordingly, the Company alleges that the proposal satisfies the premise of Section 3 (Company Brief at 80).

In addition, the Company contends that the Attorney General relies on an overly narrow interpretation of the surcharges authorized by Section 3 in contravention of the plain meaning of the statute's language (Company Brief at 281). NSTAR Gas asserts that the Legislature intended to provide gas companies flexibility to propose a broad range of mechanisms to increase the availability, feasibility, and affordability of natural gas service and, to that end, the term "including" prior to the two surcharges expressly enumerated in Section 3 means that the list is not exclusive under rules of statutory construction (Company Brief at 281-282, citing, Tze-Kit Mui v. Massachusetts Port Authority, 478 Mass. 710, 712 (2018); Federal Election Commission v. Massachusetts Citizens for Life, Inc., 769 F.2d 13, 17 (1985); Federal Land Bank of St. Paul v. Bismarck Lumber Company, 314 U.S. 95, 100 (1941)). Further, the Company claims that even under the Attorney General's narrow interpretation of Section 3, the New Customer Surcharge should be approved, characterizing NSTAR Gas's proposal as a "new service-territory-wide surcharge to aid in the financing of gas service expansion to off-main customers" (Company Brief at 262).

Finally, the Company argues that it has satisfied the statutory prerequisites for the approval of the New Customer Surcharge (Company Brief at 283). That is, NSTAR Gas asserts that it has provided detailed record information on how the Company will determine that a main or service extension is economically feasible and that the Company's CIAC policy and methodology are reasonable (Company Brief at 283, citing Exhs. ES-DPH/ANB-1, at 153, 160-161; DPU-ES 4-7; DPU-ES 12-23; DPU-ES 26-9; DPU-ES 26-11; AG 11-3, Att. (a)).

c. Energy Policy

The Company claims that developers and other customers are not converting to natural gas because of the high up-front CIAC costs, and they choose instead to move forward with delivered fuels such as oil and propane (Company Brief at 289). Therefore, the Company argues that the current CIAC framework is inconsistent with the Commonwealth's environmental policies because oil and propane are higher emitting fuels compared with natural gas (Company Brief at 289).

d. Use of Surcharge Revenues

NSTAR Gas rejects the Attorney General's argument that the Company has not adequately explained how New Customer Surcharge revenues would be administrated and argues that it is has provided a significant amount of information and evidence with details on all aspects of its proposal (Company Brief at 290). The Company maintains that the Attorney General's concerns regarding the clarity of the Company's proposal should be disregarded by the Department (Company Brief at 290-291).

e. Portfolio Perspective

The Company asserts that its portfolio perspective is simply aimed at applying excess return from projects that exceed the hurdle rate to make up part or all of the difference on another project with an ROR under the hurdle rate so that the CIAC on that project is reduced (Company Brief at 272-273 citing ES-DPH/ANB-1, at 164-165; DPU-ES 14-16; DPU-ES 14-18; DPU-ES 26-1; Tr. 4, at 526-528, 556-557). NSTAR Gas claims that the proposed portfolio perspective is consistent with the Department's decision in Boston Gas Company, D.T.E. 03-40, at 227-228 (2005) to allow expenses associated with a gas promotional program in base distribution rates. The Company avers that the Department's decision in D.T.E. 03-40 is instructive because the Department affirmed the principles that: (1) adding customers is a benefit to all existing gas customers due to the fact that fixed costs can then be spread over a larger customer base, so long as the costs of adding those new customers are equal to or less than the revenues produced by those customers; and (2) it is reasonable to include costs for adding customers in the cost of service where it is demonstrated that the revenues associated with the customers added are equal or greater than the costs incurred by using an IRR analysis to compare revenues to costs (Company Brief at 275 citing Exhs. DPU-ES 14-20; DPU-ES 26-7; AG-11-4; Tr. 4, at 496-498, 502, 526-530, 557).

C. Analysis and Findings

1. Introduction

Pursuant to Section 3, the Department is authorized to approve programs for gas distribution companies that are designed to increase the availability, affordability, and feasibility of natural gas service for new customers. St. 2014, c. 149, § 3. As discussed in detail below, the statute specifically requires the Department to review a petitioning gas company's relevant customer additions policies and requires the Department to allow alternative rate mechanisms or project review methods that facilitate access to natural gas service for new customers, including surcharges. St. 2014, c. 149, § 3(a). To that end, Section 3 authorizes the Department to establish guidelines for reviewing gas distribution companies' proposals. St. 2014, c. 149, § 3(a). The Department has previously considered whether such programs are reasonably designed to achieve the statute's purpose. D.P.U. 16-79, at 17.

2. NSTAR Gas's Main Extension and CIAC Policies

Prior to the Department's approval and the implementation of a program proposed under Section 3, the Department must review the company's determination that a main or service extension is economically feasible and review the gas company's CIAC policy and methodology. St. 2014, c. 149, § 3(a). The Department has reviewed the record evidence provided by the Company regarding its evaluation of the economic feasibility of extensions and CIAC policy (Exhs. ES-DPH/ANB-1, at 152, 153, 160-161; DPU-ES 4-7; DPU-ES 12-23; DPU-ES 26-9; DPU-ES 26-11; AG 11-3, Att. (a)).[214] These policies are founded upon the Department's long-standing precedent on customer additions. D.P.U. 12-75, at 379; D.P.U. 96-50, at 22; Boston Gas Company, D.T.E. 03-40, at 48

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[214] As noted in Section VII.F.2 above, the Department has also conducted an extensive review of the Company's accounting of CIAC in this proceeding.

(2003); Boston Gas Company, D.P.U. 88-67 (Phase I) at 282-284 (1988). Currently, NSTAR Gas determines whether each individual main or service extension is economically feasible using a CIAC model to compare the estimated cost of the project to the estimated revenues over the expected useful life of the plant investment to ensure the IRR exceeds the ROR allowed in the Company's most recent base distribution rate case (Exhs. ES-DPH/ANB-1, at 153, 161, 164; DPU-ES 26-9; DPU-ES 26-11 & Att.). If an individual main or service extension has an IRR that falls short of the approved ROR, then the customer is required to pay a CIAC in the amount necessary to make up the deficit (Exhs. ES-DPH/ANB-1, at 161; DPU-ES 26-11, Att.). NSTAR Gas has provided sufficient evidence for the Department to review its (1) process for determining whether a main or service extension is economically feasible, and (2) current CIAC policy and methodology. Based on our review, the Department finds that they are reasonable and consistent with Department precedent.

As part of NSTAR Gas's proposal, however, the Company has requested that the Department change its policy on the inclusion of plant investments associated with customer additions to allow NSTAR Gas's proposed portfolio perspective (Exhs. ES-DPH/ANB-1, at 163-166). The Company's reliance on D.T.E. 03-40 as support for a portfolio approach to including customer additions in rate base is misplaced (Exh. ES-DPH/ANB-1, at 164). In D.T.E. 03-40, the Department allowed Boston Gas Company to include promotional program expenses, not plant investments, in base distribution rates for the purposes of that case only[215] and raised a number of concerns regarding the cost-benefit analyses conducted by Boston Gas. In fact, one of the Department's criticism was that Boston Gas "did not conduct an IRR analysis for the individual promotional programs on their own separate merits" and, as such, the Department could not determine whether there were net benefits associated with particular programs." D.T.E. 03-40 at 244-246. The Company's portfolio approach ignores the Department evident fault with Boston Gas Company's similar approach. Indeed, contrary to the Company's assertions that its portfolio approach is consistent with Department precedent established in D.T.E. 03-40, the Department stated:

> Boston Gas's consolidated analysis frustrates the ability to determine whether a disproportionate level of Company resources is being invested in a particular promotional program, thereby rendering management less easily able to determine where to shift resources into endeavors that may prove to be more beneficial to both ratepayers and shareholders. Just as the Company has represented that it relies on IRR analyses to evaluate the economics of its various growth-related capital projects, separate IRR analyses for its promotional programs are necessary and appropriate in order to determine both the economics of the program in general, and the appropriate level of resources to invest into the project.

D.T.E. 03-40, at 246.

The Company's proposal to apply excess return from projects that exceed the threshold IRR to make up part or all the difference on another project with a ROR below the threshold is not consistent with the Department's findings in D.T.E. 03-40, nor with our

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215 The Department stated that with respect to the recovery of promotional expenses, in all future rate cases, all companies must present an IRR analysis that is conducted program-by-program and not on a consolidated basis. D.T.E. 03-40, at 249.

well-established precedent regarding rate base additions of revenue producing projects.[216] Western Massachusetts Electric Company, D.P.U. 85-270, at 20, 25-27 (1986). Allowing the Company to apply excess ROR from economically viable customer additions would enable the Company to include in rate base customer additions that are not economically viable. In other words, the Company's aggregate approach could allow projects with low IRRs to be subsidized by capital projects with high IRRs. This approach is likely to harm existing customers because they will be responsible for projects that have an IRR below the Company's investment threshold. It also may result in the misallocation of Company resources away from more beneficial projects. However, with appropriate parameters or protections designed to protect customers and align resources there is a potential this approach could be beneficial. Accordingly, the Department cannot at this time adopt the proposed portfolio approach without more details due to the potential it would unreasonably burden existing customers in violation of Section 3(b) and the Department's long-standing precedent on CIACs and revenue-producing plant. Therefore, the Department will establish a process (e.g., comments or a technical session) subsequent to this order with the Company addressing or installing parameters for the Department to consider and compare to our existing framework (i.e., evaluating whether a customer addition exceeds the threshold IRR

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216 Capital additions are either non-revenue producing projects or revenue producing projects. D.P.U 17-170, at 45 (2018). Non-revenue producing projects are projects that involve the replacement of distribution infrastructure for system integrity purposes. Revenue projects are those that add new customers to the system, such as main extension projects.

for the purpose of determining whether a capital project is eligible for inclusion in rate base on an individual basis). The Department is under no obligation to adopt the portfolio approach but is willing to consider an amended approach provided the parameters protect customers. The Department notes, however, that the Company may treat funds collected through the New Customer Surcharge and used to offset connection costs for a particular project as CIAC for the purpose of the IRR analysis.

3. Proposed Surcharges

As noted above, the New Customer Surcharge will apply to requests for service made on or after November 1, 2021, at new premises; it will not apply to residences or commercial facilities where gas service is already available at the time of the request (proposed M.D.P.U. No. 453 (Applicability)). The amount of the surcharge will be applied for a period of 20 years and will be equal to ten percent of monthly delivery charges for Rate G-53 customers and 30 percent of monthly delivery charges for all other rate classes except that customers taking service under the low income rate classes are exempt from the provisions of the proposed tariff (proposed M.D.P.U. No. 453 (Terms and Charge Per Month)). In reviewing the propriety of NSTAR Gas's proposed surcharges, we first consider whether they are designed to "increase the availability, affordability and feasibility of natural gas service for new customers" in accordance with Section 3.

According to NSTAR Gas, the most significant factor for whether a CIAC is required on a customer addition is whether the customer's location is on-main or off-main, particularly in unserved residential neighborhoods located some distance from the main, because of the significant costs associated with main or service extensions (Exhs. DPU-ES 14-10; DPU-ES 14-15; Tr. 4, at 554-555). Based on our review of the Company's customer additions over the last five years, the Department finds that a substantial majority—about 88 percent—of NSTAR Gas's potential new customers required no CIAC to take gas service (Exhs. ES-DPH/ANB-1, at 153; DPU-ES 14-10; DPU-ES 14-11; DPU-ES 14-15).[217] Therefore, we are persuaded by substantial record evidence that the Company's proposed surcharge will increase the costs of natural gas service for most new customers in order to subsidize the CIAC costs of a small minority of potential new customers located some distance from the gas main (Exhs. ES-DPH/ANB-1, at 153; DPU-ES 14-10; DPU-ES 14-11; DPU-ES 14-15).[218] Therefore, we cannot find that requiring all new on-main customers to pay the proposed New Customer Surcharge is consistent with the purpose of Section 3.[219]

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217 Between 2015 and 2019, NSTAR Gas added a total of 25,977 customers, 1,066 of which were required to pay a CIAC (Exh. DPU-ES 14-11). Over the same period, high CIAC costs prevented 2,251 potential new customers from taking gas service (Exh. ES-DPH/ANB-1, at 153). Therefore, out of the 28,228 requests for gas service, a CIAC was required for 3,317 of the potential customers, or in 11.75 percent of the Company's requests for new service.

218 Though NSTAR Gas presented testimony that it will experience a change in the makeup and number of its customer additions moving forward, it did not provide reviewable evidence sufficient to support a finding that the proposed surcharge applied to on-main customers would increase the affordability of gas service consistent with the intent of Section 3 (Exhs. ES-DPH/ANB-1, at 153; DPU-ES 14-11; Tr. 4, at 554-555). The Company will not be precluded from filing a petition outside of a base distribution rate case to modify its New Customer Connection Surcharge program if evidence of the Company's changing condition materializes.

219 The Department notes that based on the Company's testimony, the exclusion of new on-main customers will not significantly impact the overall proposal because, as the Company explained, in the next few years there will be nearly zero new customers

Nonetheless, the Department finds that new on-main customers who may be subject to a cost-based connection charge, should have the option to pay the New Customer Surcharge in lieu of the upfront charge. As long as customers are fully informed about the terms of the surcharge, providing on-main customers an option to pay the New Customer Surcharge in lieu of an upfront connection charge may mitigate financial barriers and improve the overall affordability of obtaining new gas service.[220]

In regards to new off-main customers, Section 3 expressly authorizes "new area surcharges applicable only to zones of new off-main customers to aid in the financing of gas service expansion to new off-main customers." St. 2014, c. 149, § 3(a). So, we will consider whether the proposed surcharge as applied to off-main customers increases the availability, affordability, and feasibility of natural gas service for new customers. NSTAR Gas detailed several examples of residential developments that declined gas service because of high CIACs (Exh. ES-DPH/ANB-1, at 159). The mean CIAC cost per home for those developments was $6,747 (Exh. ES-DPH/ANB-1, at 159). In addition, NSTAR Gas estimated that the surcharge for a residential heating customer would be $416 per year and about $8,300 over 20 years, while the Attorney General estimated that the surcharge for a residential heating customer would be about $248 per year or $4,960 over 20 years

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located on-main requesting service, rather the new customers will require extensions of the system (<u>see</u> Tr. at 554-555).

220 If the Company elects to provide this option to new on-main customers, the Company must provide the prospective customer with an estimated comparison of the CIAC or connection charge and the total lifetime New Customer Surcharge cost.

(Exhs. ES-DPH/ANB-1, at 159; AG-SJR-1, at 21). Based on these calculations, had the New Customer Surcharge been in effect at the time of these service requests, consideration of the surcharge revenues in an IRR analysis would have substantially reduced, if not eliminated, the CIAC required for most of the residential developments listed by NSTAR Gas (Exhs. ES-DPH/ANB-1, at 159; AG-SJR-1, at 21). Further, on some projects, surcharge revenue would exceed the required CIAC and could be allocated to other projects under NSTAR Gas's proposal (Exhs. ES-DPH/ANB-1, at 159; AG-SJR-1, at 21).

The Department has reviewed the Company's proposed surcharges of ten percent of the applicable delivery charges for Rate G-53 customers and 30 percent for all other customers except those receiving service under Rates R-2 and R-4 and finds the proposed rates and term reasonable (Exhs. DPU-4-29; DPU-ES 14-23; DPU-4-33; DPU-ES 14-25; DPU-ES 14-27). We find that the proposed surcharges along with the 20-year term conform with the requirements of Section 3 and strike an appropriate balance between availability of gas service and affordability of such service for off-main customers. Further, the Department finds that expansion of natural gas service will benefit existing customers because it will allow the Company to spread fixed operating costs over a larger customer base. Therefore, we find that the proposed surcharge as applied to off-main customers is reasonably designed to increase the availability, affordability, and feasibility of natural gas service (Exhs. ES-DPH/ANB-1, at 159; AG-SJR-1, at 21). Further, we find that the proposed surcharge as applied to off-main customers would not unreasonably burden existing customers.

4. Energy Policy

The Attorney General's argument that this proposal is bad public policy is based on the presumption that any program designed to increase the use of natural gas is inconsistent with the Commonwealth's energy policies to reduce GHG emissions (see Attorney General Brief at 106-107). However, in 2014, the Legislature enacted Section 3 which mandates that the Department review and approve proposals designed increase the affordability of gas service to new off-main customers, which necessarily will result in investments in new main and service extensions and increased use of natural gas. The Attorney General asks us to substitute her judgment for that of the Legislature on a public policy decision that the Legislature has made unambiguously. That we cannot do. As with Section 3, where the statutory meaning is unambiguous, that is the end of the matter; the Department will not impose an alternative construction. City of Worcester v. College Hill Properties, LLC, 465 Mass. 134, 138 (2013); Providence and Worcester Railroad Company v. Energy Facilities Siting Board, 453 Mass. 135, 141 (2009). Moreover, the Company has represented that improving access to natural gas for off-main customers will reduce the use of higher emitting fossil fuels, and the Attorney General presented no evidence in this proceeding to rebut the Company's position that this proposal will reduce GHG emissions (Exh. DPU-ES 14-16; Tr. 475). Accordingly, we find that the Attorney General's argument is without merit.

5. Use of Surcharge Revenues

The Department has reviewed the Company's proposal to review customer requests for connection and to determine the most judicious manner to use revenue from the New

Customer Surcharge based on a list of prioritization criteria, including financial, economic, environmental, societal, and operational factors (Exhs. ES-DPH/ANB-1, at 163; DPU-ES 14-12, Att.). The Department finds that the Company's proposal is sufficiently detailed and that the proposed prioritization criteria are reasonable.

6. Accounting

The funds generated by the New Customer Surcharge shall be accounted for separately from other revenues recovered through rates and credited to a segregated liability account (Exhs. ES-DPH/ANB-1, at 161; DPU-ES 26-4; Tr. 4, at 550-551). Further, the funds collected in this liability account shall be used to offset CIAC payments for projects that both require a CIAC and meet the eligibility criteria outlined by the Company (Exhs. ES-DPH/ANB-1, at 158, 161-162; DPU-ES 14-12; DPU-ES 14-16; DPU-ES 14-26; DPU-ES 26-3; Tr. 4, at 485, 547-548, 550-551). We find that the Company's proposed method to account for New Customer Surcharge revenues is appropriate. The Department directs NSTAR Gas to account for New Customer Surcharge revenue used to offset CIAC payments on projects consistent with the directives in Section VII.F.3 above.

7. Conclusion

The Department approves the Company's proposal subject to the following modifications. First, the Company shall limit application of the New Customer Surcharge to off-main customers. The Company may allow on-main customers the option to pay the New Customer Surcharge in lieu of any upfront connection charge. The surcharge may only be required for new off-main customers. Further, the New Customer Surcharge shall not apply to those customers who either opt to finance their CIAC through the Company's existing pilot program as approved by the Department in D.P.U. 16-79 or opt to pay the CIAC in full.

Consistent with the directives, above, the Company shall not implement a "portfolio approach" to evaluate whether customer additions collectively meet or exceed the threshold IRR at this time. The Department will develop a process to discuss the potential for a portfolio approach. Further, the Department directs the Company to file an annual report on the New Customer Surcharge program that details: (1) Surcharge pool funding levels and expenditures; (2) selection criteria metrics for each distribution from the Surcharge pool; (3) the IRR analysis for each customer addition; (4) the CIAC calculation for each customer addition; and (5) a qualitative assessment of the program's progress. The Company shall combine its annual report on the New Customer Surcharge with its annual Gas Expansion Pilot Program report under a general Section 3 annual report.

Further, at least 90 days prior to the effective date of the New Customer Surcharge, NSTAR Gas must file for Department review a customer education plan. The Department is mindful that the entity or person agreeing to the New Customer Surcharge may not be the entity or person ultimately subject to the surcharge (e.g., a developer or landlord may agree to the New Customer Surcharge that will be paid for by future owners or renters). Accordingly, the Company must outline an education plan to ensure that homebuyers, renters, and developers are informed of the New Customer Surcharge's financial impact, including financial impact on and notification process for subsequent homebuyers, before entering into a service agreement at a new premise. The education plan must include an online information resource, as well as an information packet deliverable directly to customers requesting new service. Both the online resource as well as the packet must detail the projected total cost of service for the specific new premise over 20 years. Further, the Company must outline the annual projected cost for the average customer in the same rate class and ZIP code over a five-year period under the following scenarios: (1) service with the New Customer Surcharge; (2) service without the New Customer Surcharge; (3) and alternatives to gas service. The Company also may use the best-available data to inform customers of each scenario's carbon emission implications.

## XIV. ENVIRONMENTALLY RESPONSIBLE GAS

### A. Company's Proposal

NSTAR Gas requested that the Department authorize the Company to procure environmentally responsible natural gas ("ERNG") supply through its normal, annual competitive solicitations and to enter into arrangements to purchase ERNG supply for terms of no more than one year in duration (Exh. ES-WJA/DPH-1, at 77). The Company stated that it is currently unable to procure ERNG through its normal procurement process because any such resources would not likely qualify as least cost (Exh. ES-WJA/DPH-1, at 78). The Company has requested preauthorization to purchase ERNG supplies even if those supplies have a cost up to ten percent higher through the solicitation than conventionally sourced natural gas (Exh. ES-WJA/DPH-1, at 74-75, 78).

The Company defined ERNG as gas that is produced from high integrity wells leveraging new technology that has less impact on the environment than traditional technologies (Exhs. ES-WJA/DPH-1, at 74; DPU-ES 12-35). The Company provided that any potential ERNG resources require certification by the third-party rating organization, Independent Energy Standards Corporation ("IES") (Exh. ES-WJA/DPH-1, at 74-75).[221] The fee paid to IES to perform a review, rating, and certification and ultimately passed on to consumers contributes to the higher cost of ERNG (Exh. DPU-ES 12-36).

The Company proposed to competitively purchase volumes of gold-level certified ERNG equivalent to three percent of annual purchased gas volumes through one-year contracts with annual increases of one percent, rising to ten percent of annual purchased volumes after seven years (Exhs. DPU-ES 12-31; DPU-ES 12-39).[222] The Company estimated that ERNG certified by IES is likely five to ten percent more costly than traditional sources and that the proposal would result in a net increase in gas costs of less than one percent relative to traditional procurement practices (Exhs. ES-WJA/DPH-1, at 76, 78; DPU-ES 12-31). The Company stated that absent the Department's approval of this proposal, it would not be able to take on the risk of recovery for slightly above market prices for commodity due to current rules and precedent (Exh. DPU-ES 26-17).

B. Positions of the Companies

The Company claims that the purchase of ERNG has several benefits, including quantifiable GHG emissions reductions, lower water use and community impacts, and the encouragement of business practices within the natural gas sector that substantially reduce

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221 IES is a third-party ratings, analytics, and certification organization launched in 2018 (Exh. ES-WJA/DPH-1, at 75).

222 A Trustwell Gold rating indicates that an operator is more responsible than 75 percent of the industry (Exh. ES-WJA/DPH-1, at 75).

environmental impacts (Company Brief at 434, citing Exhs. ES-WJA/DPH-1, at 76; DPU-ES 26-14). The Company argues that the Department should approve its proposal to procure ERNG based on the following: (1) the program will be immediately implemented upon approval; (2) the program will minimize cost impacts with the proposed limitations on volume and cost; (3) the program design assures that all customers will financially support the program; and (4) environmental benefits will be realized as the procurement strategy is easily melded into the existing procurement process (Company Brief at 435 citing Exhs. DPU-ES 26-13; DPU-ES 26-14; DPU-ES 12-31). No other party commented on the Company's proposal.

1. Standard of Review

In evaluating a local gas distribution company's ("LDC") options for the acquisition of commodity and/or incremental resources under G.L. c. 164, § 94A ("Section 94A"), the Department examines whether the acquisition of the resource is consistent with the public interest. Commonwealth Gas Company, D.P.U. 94-174-A at 27 (1996). In order to demonstrate that the proposed acquisition of commodity and/or incremental resources is consistent with the public interest, an LDC must show that the acquisition (1) is consistent with its portfolio objectives and (2) compares favorably to the range of alternative options reasonably available to the company at the time of the acquisition or contract renegotiation. D.P.U. 94-174-A at 27.

To establish that a resource is consistent with the Company's portfolio objectives, the Company may refer to portfolio objectives established in a recently approved forecast and supply plan under G.L. c. 164, § 69I or in a recent review of supply contracts under Section 94A, or the Company may describe its objectives in the filing accompanying the proposed resource. D.P.U. 94-174-A at 27-28. The Department compares the proposed resource acquisition to current market offerings by examining relevant price and non-price attributes of each contract to ensure a contribution to the strength of the overall supply portfolio. D.P.U. 94-174-A at 28. As part of the review of relevant price and non-price attributes, the Department considers whether the pricing terms are competitive with those for the broad range of capacity, storage, and commodity options that were available to the LDC at the time of the acquisition, as well as with those opportunities that were available to other LDCs in the region. D.P.U. 94-174-A at 28. In addition, the Department determines whether the acquisition satisfies the LDC's non-price objectives including, but not limited to, flexibility of nominations and reliability and diversity of supplies. D.P.U. 94-174-A at 28-29. In making these determinations, the Department considers whether the LDC used a competitive solicitation process that was fair, open, and transparent. The Berkshire Gas Company, D.T.E. 02-56, at 10 (2002); Bay State Gas Company, D.T.E. 02-52, at 8 (2002); KeySpan Energy Delivery New England, D.T.E. 02-54, at 9 (2002); The Berkshire Gas Company, D.T.E. 02-19, at 11 (2002).

2. Analysis and Findings

To determine whether an acquisition of natural gas resources is consistent with the public interest, the Department weighs a company's portfolio objectives and the range of alternative options reasonably available to the company at the time of the acquisition or contract renegotiation. D.P.U. 94-174-A at 27. The Company states that it submitted the proposal to acquire ERNG in this base distribution rate case instead of in a petition filed pursuant to Section 94A because the Company intends to procure ERNG through contracts with terms of one year or less and there is no contract proceeding in which this proposal could otherwise be made (Exh. DPU-ES 26-16).[223] During this proceeding, however, NSTAR Gas did not submit any specific resource acquisition or contract for the Department's review; instead, the Company has requested preauthorization to procure ERNG through one-year contracts at a cost that may be up to ten percent higher than competitive alternatives (Exh. ES-WJA/DPH-1, at 77). Without evidence of NSTAR Gas's portfolio objectives and the range of alternative options reasonably available to the Company, the Department cannot determine whether the proposed acquisition of ENRG is consistent with the public interest. Accordingly, we deny the Company's request for preauthorization to procure ERNG resources.

Before the Company seeks the Department's approval of a contract to purchase ERNG, the Company should address the following issues. With respect to the alleged benefits of ERNG, the Company asserts that its procurement of ERNG would yield incremental environmental benefits and, thus, further the Commonwealth's energy policies; however, the Company has not studied or analyzed the extent to which its current resource

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[223] Though Section 94A mandates only that contracts covering a period in excess of one year to purchase gas be filed with the Department for approval, the Company is not precluded from submitting a petition to the Department pursuant to Section 94A for approval of a contract to acquire ERNG for a one-year term.

portfolio already qualifies as environmentally responsible (Exhs. DPU-ES 12-30; DPU-ES 12-32; DPU-ES 12-38; DPU-ES 26-13; DPU-ES 26-14). Prior to requesting Department approval to procure ERNG, for the Department to weigh whether the higher costs of IES certification are consistent with the public interest, the Company must review its current portfolio of gas supply resources to determine whether these resources are produced from high integrity wells leveraging new technologies that reduce the environmental impact of gas production.

Next, the record demonstrates that there is a limited pool of producers certified by IES (Exhs. DPU-ES 12-37; DPU-ES 26-16). Accordingly, the Department cautions the Company that it will have to demonstrate the RFP processes used to acquire ERNG are truly competitive.[224]

As explained above, the record in this case is insufficient to authorize procurement of future ERNG supply contracts. The Company's efforts, however, to act in line with the Commonwealth's GHG emissions goals are appreciated. See D.P.U. 20-80, Vote and Order Opening Investigation at 1-2.

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224 In this proceeding, the Company provided a study from IES on customers' willingness to pay more for IES-certified ERNG (Exh. DPU-ES 26-13). If the Company submits evidence on this topic in a future proceeding, the Company should engage its own customer base to determine their willingness to pay for gas that is more environmentally responsible than the Company's current portfolio.

## XV. TERMS AND CONDITIONS TARIFF

### A. Introduction

NSTAR Gas's Terms and Conditions tariff ("T&C Tariff"), M.D.P.U. No. 400D, sets out the general rules for the provision of distribution service to its customers from the initiation of service to the procurement of gas (Exh. ES-RDC/LMC-1, at 6). The responsibilities of the customer, Company, and supplier are delineated in the T&C Tariff to ensure that service is provided in a safe and fair manner to all customers (Exh. ES-RDC/LMC-1, at 6).

In this proceeding, NSTAR Gas proposed M.D.P.U. No. 400E, to implement a number of revisions to its T&C Tariff (Exhs. ES-RDC/LMC-1, at 6-14; ES-RDC/LMC-3). In particular, the Company proposed revisions to Sections 2.0, 4.0, 11.0, 12.0, 13.0, 14.0, 15.0, 16.0, 19.0, and 24.0 and Appendix B (Exhs. ES-RDC/LMC-1 at 7-9; ES-RDC/LMC-3). In Section 2.0, the Company revised certain definitions (proposed M.D.P.U. No. 400E, § 2.0). Sections 4.0, 11.0, 12.0, 13.0, 16.0, 19.0 and 24.0 relate to Supplier Service and the responsibilities of competitive suppliers, while Sections 14.0 and 15.0 relate to the rights and obligations of the Company's customers (proposed M.D.P.U. No. 400E). In Appendix B, the Company proposed to change the Returned Check Fee to reflect current costs and to establish a Sales Tax Abatement Fee to recover certain administrative costs (Exhs. ES-RDC/LMC-1, at 13-14: ES-RDC/LMC-3, at 87)

On June 30, 2020, the Company filed a motion to withdraw its proposed revisions to the T&C Tariff as they relate to Supplier Service ("Motion to Withdraw"). The Department granted the Motion to Withdraw on July 1, 2020. On July 3, 2020, the Company filed a revised T&C Tariff for Department review and approval (Exh. ES-RDC/LMC-2 (Rev.)).

The Company stated that it determined that the necessary changes to the T&C Tariff as they relate to Supplier Service would better be addressed through a statewide collaborative process outside of this rate proceeding. According to the Company, addressing the needed changes through a collaborative process will allow a more comprehensive discussion of the proposed changes, as well as changes addressing reliability (Motion to Withdraw at 2).

### B. Positions of the Parties

#### 1. Direct Energy

Direct Energy agrees with the Company's Motion to Withdraw and proposed that the Department direct the Company to develop a collaborative process that includes all licensed natural gas suppliers, direct customers, and groups that represent natural gas customers (Direct Energy Brief at 2). Further, Direct Energy proposed certain elements of the collaborative process to include identification of issues, proper communication among collaborative participants, and establishment of set schedules (Direct Energy Brief at 2-3).

#### 2. The Energy Consortium

TEC requests that the Department initiate a collaborative proceeding to address supplier Terms & Conditions that is inclusive, transparent, and timely in reaching its conclusion (TEC Brief at 18). In particular, TEC proposes that such a collaborative be docketed, with notification to intervenors in this proceeding, and with a specific deadline for the conclusion of the collaborative's activities (TEC Brief at 16).

C. Analysis and Findings

In Natural Gas Unbundling, D.T.E 98-32-A at 19-20 (1998), the Department approved partial model tariff terms and conditions applicable to all LDCs. In D.T.E. 98-32-D at 5 (2000), the Department approved the remaining model tariff terms and conditions ("Model T&Cs"). The Model T&Cs were developed through the efforts of a collaborative that was established to develop the practices and procedures for the provision of supplier sales services and LDC distribution and default services to customers[225]. Company specific terms and conditions tariffs became effective on November 1, 2000. D.P.U. 98-32-E (2000).

Recognizing that there are operational differences among the jurisdictional LDCs, the Department's goal is to ensure an efficient retail natural gas market that allows consumers to engage competitive commodity suppliers who compete for the provision of least-cost and reliable natural gas commodity. To the extent possible, uniform terms and conditions across LDCs will allow suppliers to better operate more effectively and efficiently in the Commonwealth.

The Department periodically uses collaborative initiatives and working groups to reach a consensus among stakeholders that are affected by a particular issue. Distributed Generation Working Group, D.P.U. 11-75-A at 4-5 (2012); Energy Efficiency Guidelines, D.P.U. 08-50-A at 5 (2009); Standards for Arrearage Management Programs, D.T.E. 05-86,

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[225] The collaborative participants included the LDCs, Attorney General, energy marketers, the Associated Industries of Massachusetts, Inc., DOER, and TEC.

at 15 (2006); Gas Unbundling Collaborative, D.T.E. 98-32-B (1999); Street Restoration Standards, D.T.E. 98-22, at 2 & n.3 (1999); Electric Industry Restructuring, D.P.U. 95-30, at 46-47 (1995). The Department agrees with the Company, Direct Energy, and TEC that a collaborative process is an appropriate means to review and, where necessary, revise the LDCs' existing terms and conditions. Consistent with their recommendation, the Department convenes a working group, comprising all LDCs, licensed gas suppliers and marketers, the Attorney General, DOER, and TEC, and invites all parties to participate.[226]

No later than 45 days from the issuance of this Order, the working group should initiate its first meeting and begin deliberating regarding possible changes to the Model T&Cs as well as operational issues with the goal of reaching a consensus on a Model T&C for the Department's review and approval.[227] The working group is directed to prepare a report containing consensus recommendations for changes to the Model T&Cs as well as identifying any differences amongst the members of the working group. The Department request submission of the report by September 30, 2021. In the event that, despite the collaborative effort, a consensus cannot be reached on all the issues raised by the members of the working

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226 To facilitate the initiation of the working group, the Department directs the Secretary of the Department to service a copy of this Order by electronic means on all jurisdictional gas companies. Also, the Department requests that, initially, the Company coordinate communications for the establishment of the working group.

227 We expect that the working group will address all of the operational issues identified by Direct Energy in this proceeding. These issues relate to the timely information about capacity, OFO-related communications, enrollment transactions, the accuracy of customer data, the electronic data interchange, the timeliness of meter readings, and meeting Adjusted Target Volume/cash-out – related deadlines (Exhs. DE-KS/MH-1, at 28-39; DPU-ES 36-8).

group, similar to previous collaborative efforts, the Department will review those agreements that have been reached and adjudicate any outstanding matters.

## XVI. 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 | 82,792,101 | 2,039,941 | (68,821) | 84,763,221 |
| Uncollectible O&M due to increase | 586,988 | 0 | (235,558) | 351,430 |
| Depreciation & Amortization | 44,001,019 | (2,473,355) | (2,530,966) | 38,996,698 |
| Taxes Other Than Income Taxes | 29,757,890 | 3,367,353 | (42,750) | 33,082,493 |
| Income Taxes | 17,229,964 | (1,848,755) | (1,541,340) | 13,839,869 |
| Return on Rate Base | 68,799,703 | (7,252,246) | (4,676,633) | 56,870,825 |
| Total Cost of Service | 243,167,666 | (6,167,062) | (9,096,068) | 227,904,536 |
| **OPERATING REVENUES** | | | | |
| Operating Revenues | 199,679,414 | (3,192,276) | 3,192,276 | 199,679,414 |
| Revenue Adjustments | 5,453,998 | 41,277 | (41,277) | 5,453,998 |
| Total Operating Revenues | 205,133,412 | (3,150,999) | 3,150,999 | 205,133,412 |
| **Total Revenue Deficiency** | **38,034,254** | **(3,016,063)** | **(12,247,067)** | **22,771,124** |

## B. Schedule 2 – Operations and Maintenance Expenses

| | PER COMPANY | COMPANY ADJUSTMENT | DPU ADJUSTMENT | PER ORDER |
|---|---|---|---|---|
| O&M Per Books | 369,857,380 | 0 | 0 | 369,857,380 |
| Normalizing Adjustments | (297,504,484) | 150,263 | 0 | (297,354,221) |
| Test Year O&M Expense | 72,352,896 | 150,263 | 0 | 72,503,159 |
| **ADJUSTMENTS TO TEST YEAR O&M EXPENSE:** | | | | |
| Compensation: Payroll Expense | 2,715,737 | 22,639 | 0 | 2,738,376 |
| Compensation: Incremental FTE Hires | 1,458,937 | (67,989) | (379,616) | 1,011,332 |
| Compensation: Variable Compensation | (1,107,192) | 1,516 | 0 | (1,105,676) |
| Employee Benefits Costs | | | | |
| Existing Payroll | 943,382 | (206,778) | 0 | 736,604 |
| Incremental FTE Hires | 918,828 | (654,907) | (131,529) | 132,392 |
| Dues and Memberships | 29,582 | 0 | 0 | 29,582 |
| Enterprise IT Projects Expense | 2,732,339 | 2,123,119 | (211,348) | 4,644,110 |
| Insurance Expense And Injuries & Damages | 132,813 | 5,483 | 0 | 138,296 |
| Lease Expense | 1,437,524 | 995,334 | (175,892) | 2,256,966 |
| Postage Expense | 12,609 | 15,129 | 0 | 27,738 |
| Rate Case Expense | 619,421 | 60,679 | (340,050) | 340,050 |
| Uncollectible Accounts | (476,028) | 0 | (104,736) | (580,764) |
| Regulatory Assessment | 0 | 0 | 1,274,350 | 1,274,350 |
| Residual O&M Inflation Allowance | 1,021,253 | (404,547) | 0 | 616,706 |
| Sum of O&M Expense Adjustments | 10,439,204 | 1,889,678 | (68,821) | 12,260,061 |
| **Total O&M Expense** | **82,792,101** | **2,039,941** | **(68,821)** | **84,763,221** |

## C. Schedule 3 – Depreciation and Amortization Expenses

| | PER COMPANY | COMPANY ADJUSTMENT | DPU ADJUSTMENT | PER ORDER |
|---|---|---|---|---|
| Depreciation and Amortization Expense | 40,803,230 | (3,474,438) | (1,729,166) | 35,599,626 |
| Amortization of Deferred Assets | | | | |
| Acquisition Premium | 2,384,440 | 0 | 0 | 2,384,440 |
| Hardship Receivables | 602,516 | 0 | (301,258) | 301,258 |
| Merger Costs to Achieve | 484,752 | 0 | 0 | 484,752 |
| CIAC Tax Gross-Up | (273,919) | 0 | 0 | (273,919) |
| Amortization of Exogenous Property Taxes | 0 | 1,001,083 | (500,542) | 500,541 |
| **Total Depreciation and Amortization Expense** | **44,001,019** | **(2,473,355)** | **(2,530,966)** | **38,996,698** |

D. Schedule 4 – Rate Base and Return on Rate Base

| | PER COMPANY | COMPANY ADJUSTMENT | DPU ADJUSTMENT | PER ORDER |
|---|---|---|---|---|
| Utility Plant in Service | 1,638,592,655 | (97,886,211) | (64,698,718) | 1,476,007,726 |
| LESS: | | | | |
| Reserve for Depreciation | 473,129,794 | (2,177,465) | (23,108,350) | 447,843,979 |
| Reserve for Amortization | 4,047,888 | (215,399) | (425,082) | 3,407,407 |
| Net Utility Plant in Service | 1,161,414,973 | (95,493,347) | (41,165,286) | 1,024,756,340 |
| ADDITIONS TO PLANT: | | | | |
| Cash Working Capital | 10,236,494 | 509,908 | (10,521) | 10,735,880 |
| Materials and Supplies | 4,138,521 | (426,294) | 0 | 3,712,227 |
| Total Additions to Plant | 14,375,015 | 83,614 | (10,521) | 14,448,108 |
| DEDUCTIONS FROM PLANT: | | | | |
| Reserve for Deferred Income Tax | 164,973,596 | (5,284,189) | (14,653,521) | 145,035,886 |
| Estimated Excess Deferred Taxes | 112,046,962 | (4,517,930) | 2,935,969 | 110,465,001 |
| Customer Deposits | 1,240,987 | 19,783 | 0 | 1,260,770 |
| Customer Advances | 2,258,519 | 63,218 | 0 | 2,321,737 |
| Total Deductions from Plant | 280,520,064 | (9,719,118) | (11,717,552) | 259,083,394 |
| RATE BASE | 895,269,924 | (85,690,615) | (29,458,255) | 780,121,053 |
| COST OF CAPITAL | 7.68% | -0.08% | -0.39% | 7.29% |
| **RETURN ON RATE BASE** | **68,799,703** | **(7,252,246)** | **(4,676,633)** | **56,870,825** |

E. Schedule 5 – Cost of Capital

PER COMPANY

| | PRINCIPAL | PERCENTAGE | COST | RATE OF RETURN |
|---|---|---|---|---|
| Long-Term Debt | 523,193,474 | 45.15% | 4.33% | 1.95% |
| Preferred Stock | 0 | 0.00% | 0.00% | 0.00% |
| Common Equity | 635,646,596 | 54.85% | 10.45% | 5.73% |
| Total Capital | 1,158,840,070 | 100.00% | | 7.68% |
| Weighted Cost of | | | | |
| Debt | | | | 1.95% |
| Preferred | | | | 0.00% |
| Equity | | | | 5.73% |
| Cost of Capital | | | | 7.68% |

COMPANY ADJUSTMENTS

| | PRINCIPAL | PERCENTAGE | COST | RATE OF RETURN |
|---|---|---|---|---|
| Long-Term Debt | 523,354,300 | 45.16% | 4.14% | 1.87% |
| Preferred Stock | 0 | 0.00% | 0.00% | 0.00% |
| Common Equity | 635,646,596 | 54.84% | 10.45% | 5.73% |
| Total Capital | 1,159,000,896 | 100.00% | | 7.60% |
| Weighted Cost of | | | | |
| Debt | | | | 1.87% |
| Preferred | | | | 0.00% |
| Equity | | | | 5.73% |
| Cost of Capital | | | | 7.60% |

PER ORDER

| | PRINCIPAL | PERCENTAGE | COST | RETURN |
|---|---|---|---|---|
| Long-Term Debt | 525,000,000 | 45.23% | 4.13% | 1.87% |
| Preferred Stock | 0 | 0.00% | 0.00% | 0.00% |
| Common Equity | 635,646,596 | 54.77% | 9.90% | 5.42% |
| Total Capital | 1,160,646,596 | 100.00% | | 7.29% |
| Weighted Cost of | | | | |
| Debt | | | | 1.87% |
| Preferred | | | | 0.00% |
| Equity | | | | 5.42% |
| Cost of Capital | | | | 7.29% |

F. Schedule 6 – Cash Working Capital

| | PER COMPANY | COMPANY ADJUSTMENT | DPU ADJUSTMENT | PER ORDER |
|---|---|---|---|---|
| Non-Gas O&M Expenses | 82,792,101 | 2,039,941 | (68,821) | 84,763,221 |
| Less: Uncollectible Accounts | (3,997,564) | 0 | 0 | (3,997,564) |
| Add: Total Taxes Other Than Income Taxes | 29,757,890 | 3,367,353 | (42,750) | 33,082,493 |
| **Total Costs Applicable to Cash Working Capital** | 108,552,426 | 5,407,294 | (111,571) | 113,848,149 |
| Cash Working Capital Factor | 9.43% | 9.43% | 9.43% | 9.43% |
| **Cash Working Capital Allowance - Company Expense** | **10,236,494** | **509,908** | **(10,521)** | **10,735,880** |

G. Schedule 7 – Taxes Other Than Income Taxes

| | PER COMPANY | COMPANY ADJUSTMENT | DPU ADJUSTMENT | PER ORDER |
|---|---|---|---|---|
| Property Tax | 26,399,122 | 3,294,288 | 0 | 29,693,410 |
| Payroll Tax | | | | |
| FICA | 2,268,984 | 8,779 | (42,750) | 2,235,013 |
| Medicare | 632,388 | 5 | 0 | 632,393 |
| Federal Unemployment | 15,294 | (679) | 0 | 14,615 |
| State Unemployment | 216,920 | (4,097) | 0 | 212,823 |
| State Insurance Premium Excise Tax | 25,057 | 0 | 0 | 25,057 |
| Universal Health (MA) | 21,730 | (1,222) | 0 | 20,508 |
| State Sales and Use Tax | 43,832 | 0 | 0 | 43,832 |
| Paid Family Medical Leave | 134,563 | 70,279 | 0 | 204,842 |
| **Taxes Other Than Income** | **29,757,890** | **3,367,353** | **(42,750)** | **33,082,493** |

## H. Schedule 8 – Income Taxes

| | PER COMPANY | COMPANY ADJUSTMENT | DPU ADJUSTMENT | PER ORDER |
|---|---|---|---|---|
| Rate Base | 895,269,924 | (85,690,615) | (29,458,255) | 780,121,053 |
| Return on Rate Base | 68,799,703 | (7,252,246) | (4,676,633) | 56,870,825 |
| Add: Merger costs non-deductible | 242,451 | 0 | 0 | 242,451 |
| Add: Rate differential state tax to 8% | 18,296 | 0 | 0 | 18,296 |
| Add: Non-Deductible Depreciation | 9,596 | 0 | 0 | 9,596 |
| Less: Interest Expense | (17,482,831) | 2,333,983 | 576,187 | (14,572,661) |
| Less: EDIT to 21% (Property and Non-Property) | (1,430,007) | 0 | 0 | (1,430,007) |
| Less: Amortization of Investment Tax Credit | (154,236) | 0 | 0 | (154,236) |
| Total Adjustments | (18,796,731) | 2,333,983 | 576,187 | (15,886,561) |
| **Taxable Income Base** | 50,002,972 | (4,918,263) | (4,100,446) | 40,984,264 |
| Gross Up Factor | 1.3759 | 1.3759 | 1.3759 | 1.3759 |
| **Taxable Income** | 68,799,089 | (6,767,038) | (5,641,803) | 56,390,248 |
| Massachusetts Income Tax (8%) | 5,503,927 | (541,363) | (451,344) | 4,511,220 |
| Federal Taxable Income | 63,295,162 | (6,225,675) | (5,190,459) | 51,879,028 |
| Federal Income Tax Calculated (21%) | 13,291,984 | (1,307,392) | (1,089,996) | 10,894,596 |
| **Total Income Taxes Calculated** | 18,795,911 | (1,848,755) | (1,541,340) | 15,405,816 |
| Add: Rate differential state tax to 8% | 18,296 | 0 | 0 | 18,296 |
| Less: EDIT to 21% (Property and Non-Property) | (1,430,007) | 0 | 0 | (1,430,007) |
| Less: Amortization of Investment Tax Credit | (154,236) | 0 | 0 | (154,236) |
| **Total Income Taxes** | **17,229,964** | **(1,848,755)** | **(1,541,340)** | **13,839,869** |

I. Schedule 9 – Revenues

| | PER COMPANY | COMPANY ADJUSTMENT | DPU ADJUSTMENT | PER ORDER |
|---|---|---|---|---|
| **Base Distribution Revenue:** | | | | |
| Billed Sales - Distribution | 166,215,356 | 613,746 | (613,746) | 166,215,356 |
| Revenue Decoupling Adjustment | 3,426,520 | (1,583,375) | 1,583,375 | 3,426,520 |
| GSEAP Revenue | 32,005,076 | (2,222,647) | 2,222,647 | 32,005,076 |
| TACF Credit | (1,967,538) | 0 | 0 | (1,967,538) |
| Total Base Distribution Revenue | 199,679,414 | (3,192,276) | 3,192,276 | 199,679,414 |
| **Other Operating Revenue Adjustments:** | | | | |
| Late Payment Charges | 369,841 | (10,452) | 10,452 | 369,841 |
| Returned Check Fees | 119,490 | (23,898) | 23,898 | 119,490 |
| Reactivation Fee | 177,825 | (9,150) | 9,150 | 177,825 |
| Sales Tax Abatement Fee | 20,544 | (20,544) | 20,544 | 20,544 |
| Property Rent (Gas and Electric) | 2,332,788 | 100,133 | (100,133) | 2,332,788 |
| Other Revenues (Gas and Electric) | 3,221 | (5,711) | 5,711 | 3,221 |
| Special Contract Adjustments | 2,430,289 | 10,899 | (10,899) | 2,430,289 |
| Subtotal: Other Operating Revenue Adjustments | 5,453,998 | 41,277 | (41,277) | 5,453,998 |
| **Adjusted Total Operating Revenues** | **205,133,412** | **(3,150,999)** | **3,150,999** | **205,133,412** |

## J. Schedule 10 – Allocation to Rate Classes

| RATE CLASS | TOTAL TEST YEAR REVENUE | TEST YEAR BASE DISTRIBUTION REVENUE | BASE DISTRIBUTION REVENUE ADJ. (GSEP/TACF/RDAF) | ADJUSTED TEST YEAR DISTRIBUTION REVENUE | BASE DISTRIBUTION REVENUE AT EROR | TEST YEAR RECONCILING REVENUE | CHANGE IN RECONCILING REVENUE | REVENUE INCREASE IN EXCESS OF 10% CAP | BASE DISTRIBUTION REVENUE ALLOCATOR | ALLOCATION OF BASE DISTRIBUTION INCREASE IN EXCESS OF 10% CAP | BASE DISTRIBUTION REVENUE PER 10% CAP |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) | (k) |
| Residential (R-1 and R-2) | $ 4,555,173 | $ 2,682,647 | $ 197,553 | $ 2,880,199 | $ 4,126,409 | $ 1,872,526 | $ (194,963) | $ 793,281 | $ - | $ - | $ 3,333,128 |
| Residential (R-3 and R-4) | $ 294,122,722 | $ 108,521,622 | $ 20,063,081 | $ 128,584,703 | $ 141,210,315 | $ 185,601,100 | $ (19,883,964) | $ - | $ 141,210,315 | $ 513,088 | $ 141,723,403 |
| Rate G-41 | $ 50,627,898 | $ 16,258,805 | $ 3,069,479 | $ 19,328,284 | $ 19,751,383 | $ 34,369,093 | $ (3,080,760) | $ - | $ 19,751,383 | $ 71,767 | $ 19,823,150 |
| Rate G-42 | $ 64,361,889 | $ 14,786,661 | $ 3,260,049 | $ 18,046,710 | $ 24,395,584 | $ 49,575,229 | $ (3,265,710) | $ - | $ 24,395,584 | $ 88,641 | $ 24,484,226 |
| Rate G-43 | $ 28,922,561 | $ 6,203,901 | $ 1,392,918 | $ 7,596,819 | $ 8,810,710 | $ 22,718,660 | $ (1,398,663) | $ - | $ 8,810,710 | $ 32,014 | $ 8,842,723 |
| Rate G-51 | $ 11,241,392 | $ 3,220,531 | $ 826,934 | $ 4,047,464 | $ 3,331,194 | $ 8,020,861 | $ (783,587) | $ - | $ 3,331,194 | $ 12,104 | $ 3,343,298 |
| Rate G-52 | $ 25,709,921 | $ 5,231,383 | $ 1,409,686 | $ 6,641,069 | $ 7,829,498 | $ 20,478,539 | $ (1,450,596) | $ - | $ 7,829,498 | $ 28,448 | $ 7,857,946 |
| Rate G-53 | $ 57,953,213 | $ 9,309,807 | $ 3,244,358 | $ 12,554,164 | $ 12,995,445 | $ 48,643,406 | $ (3,247,468) | $ - | $ 12,995,445 | $ 47,219 | $ 13,042,664 |
| Total Company | $ 537,494,770 | $ 166,215,356 | $ 33,464,058 | $ 199,679,414 | $ 222,450,537 | $ 371,279,414 | $ (33,305,710) | $ 793,281 | $ 218,324,128 | $ 793,281 | $ 222,450,537 |

| RATE CLASS | BASE DISTRIBUTION REVENUE DECREASE IN EXCESS OF 0% FLOOR | BASE DISTRIBUTION REVENUE ALLOCATOR | ALLOCATION OF BASE DISTRIBUTION DECREASE IN EXCESS OF 0% FLOOR | BASE DISTRIBUTION REVENUE PER 10% CAP AND 0% FLOOR | BASE DISTRIBUTION REVENUE IN EXCESS OF 200% CAP | BASE DISTRIBUTION REVENUE ALLOCATOR | ALLOCATION OF BASE DISTRIBUTION REVENUE INCREASE PER 200% CAP | PER ORDER BASE DISTRIBUTION REVENUE | PER ORDER DISTRIBUTION REVENUE INCREASE (%) | PER ORDER TOTAL REVENUE INCREASE (%) |
|---|---|---|---|---|---|---|---|---|---|---|
| | (l) | (m) | (n) | (o) | (p) | (q) | (r) | (s) | (t) | (u) |
| Residential (R-1 and R-2) | $ - | $ - | $ - | $ 3,333,128 | $ - | $ - | $ - | $ 3,333,128 | 15.7% | 10.0% |
| Residential (R-3 and R-4) | $ - | $ 141,210,315 | $ (434,036) | $ 141,289,367 | $ - | $ 141,210,315 | $ 1,189,545 | $ 142,478,912 | 10.8% | 4.8% |
| Rate G-41 | $ - | $ 19,751,383 | $ (60,709) | $ 19,762,441 | $ - | $ 19,751,383 | $ 166,384 | $ 19,928,825 | 3.1% | 1.2% |
| Rate G-42 | $ - | $ 24,395,584 | $ (74,984) | $ 24,409,241 | $ 1,605,578 | $ - | $ - | $ 22,803,663 | 26.4% | 7.4% |
| Rate G-43 | $ - | $ 8,810,710 | $ (27,081) | $ 8,815,642 | $ - | $ 8,810,710 | $ 74,221 | $ 8,889,863 | 17.0% | 4.5% |
| Rate G-51 | $ (660,820) | $ - | $ - | $ 4,004,117 | $ - | $ - | $ - | $ 4,004,117 | -1.1% | 0.0% |
| Rate G-52 | $ - | $ 7,829,498 | $ (24,065) | $ 7,833,881 | $ - | $ 7,829,498 | $ 65,955 | $ 7,899,836 | 19.0% | 4.7% |
| Rate G-53 | $ - | $ 12,995,445 | $ (39,944) | $ 13,002,720 | $ - | $ 12,995,445 | $ 109,473 | $ 13,112,192 | 4.4% | 1.0% |
| Total Company | $ (660,820) | $ 214,992,934 | $ (660,820) | $ 222,450,537 | $ 1,605,578 | $ 190,597,350 | $ 1,605,578 | $ 222,450,537 | 13.2% | 4.3% |

Notes:
Col. (a): See ES-RDC-2, Workpaper 9
Col. (b): See ES-RDC-2 (Rev. 1), Workpaper 9
Col. (c): See ES-RDC-2 (Rev.1), Workpapers 8 and 9
Col. (d): Col. (b) + Col. (c)
Col. (e): Per the ACOSS approved in this Order
Col. (f): Col. (a) - Col. (b)
Col. (g): See Workpapers 7 col.s (e), (g), & (i), and 9 col.s (d), (f), & (h) for allocation of proposed rate increase in test year reconciling revenue
Col. (h): IF (Col. (a) * 0.1) - Col. (g) < (Col. (e) - Col. (b)) Then Col (e) - Col. (b) -((Col. (a) * 0.1) - Col. (g)), Else 0
Col. (i): IF Col (h) > 0, Then 0, Else Col. (e)
Col. (j): IF Col. (h) > 0, Then 0, Else (Col. (i) / Col. (i)Total) * Col. (h)Total

Notes:
Col. (k): Col. (e) - Col. (h) + Col. (j)
Col. (l): IF (Col. (b) - Col. (g)) > Col. (k), then Col. (k) - (Col. (b) - Col. (g)), Else 0
Col. (m): IF Col. (h) = 0 AND Col. (l) = 0, Then Col. (e), Else 0
Col. (n): IF Col. (m) > 0, Then (Col. (m) / Col. (m)Total) * Col. (l)Total, Else 0
Col. (o): Col. (k) - Col. (l) + Col. (n)
Col. (p): IF (Col. (d) * (1 + Col. (t)Total *2) < Col. (o), Then Col. (o) - ((Col. (d) * (1 + Col. (t)Total *2)), Else 0
Col. (q): IF Col. (h) = 0 AND Col. (l) = 0 AND Col. (p) = 0, then Col. (e.), Else 0
Col. (r): IF Col. (q) > 0, Then (Col. (q) / Col. (q)Total) * Col. (p)Total, Else 0
Col. (s): Col. (o) - Col. (p) + Col. (r)
Col. (t): (Col. (s) / Col. (d)) - 1
Col. (u): ((Col. (f) + Col. (g) + Col. (s)) / Col. (a)) - 1

Note – This Schedule is for Illustrative Purposes Only.

## XVII. ORDER

Accordingly, after due notice, hearing, opportunity for comment, and consideration, it is

ORDERED: That the tariffs M.D.P.U. Nos. 400E, 401G, 402S, 403D, 404C, 409D, 411, 420D, 421G, 422D, 423G, 430D through 435D, 450C, 451C, 452C, and 453 filed by NSTAR Gas Company on July 2, 2020, effective May 1, 2020, are DISALLOWED; and it is

FURTHER ORDERED: That NSTAR Gas Company shall file new schedules of rates and charges designed to increase annual gas revenues by $22,771,124; 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 directives contained in this Order; and it is

<u>FURTHER ORDERED</u>: That the new rates shall apply to natural gas consumed on or after November 1, 2020, but, unless otherwise ordered by the Department, shall not become effective earlier than seven days after the rates are filed with supporting data demonstrating that such rates comply with this Order.

By Order of the Department,

/s/
Matthew H. Nelson, Chair

/s/
Robert E. Hayden, Commissioner

/s/
Cecile M. Fraser, 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.