The Commonwealth of Massachusetts

DEPARTMENT OF PUBLIC UTILITIES

D.P.U. 10-114 March 31, 2011

Petition of New England Gas Company, pursuant to G.L. c. 164, § 94 and 220 C.M.R. § 5.00 et seq., for Approval of a General Increase in Gas Distribution Rates, a Targeted Infrastructure Recovery Factor, and a Revenue Decoupling Mechanism, set forth in the following tariffs: M.D.P.U. Nos. 1002B and 1003A through 1024A.

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I. INTRODUCTION

A. Procedural History

On September 16, 2010, New England Gas Company ("NEGC" or "Company") filed a petition with the Department of Public Utilities ("Department"), pursuant to G.L. c. 164, § 94 and 220 C.M.R. § 5.00 et seq., for a general increase in its base distribution rates for gas customers of $6,166,020. In addition to a base distribution rate increase, NEGC seeks approval of: (1) a revenue decoupling mechanism ("RDM"); and (2) a targeted infrastructure recovery factor ("TIRF") intended to recover the costs associated with an accelerated replacement of cast-iron and steel mains and associated facilities. The Department docketed the petition as D.P.U. 10-114 and suspended the effective date of the tariffs until April 1, 2011, for further investigation.[1] NEGC's last increase in base distribution rates was in 2009. New England Gas Company, D.P.U. 08-35 (2009).

NEGC provides natural gas distribution service to approximately 54,000 residential and commercial and industrial ("C&I") customers in the Massachusetts communities of (1) Fall River, (2) Somerset, (3) Swansea, (4) Westport, (5) North Attleborough, and (6) Plainville (Exh. NEGC-JMSw-1, at 2-3). NEGC is a division of Southern Union Company ("Southern Union") (Exh. NEGC-JMSw-1, at 2-3). Southern Union owns and operates assets in the natural gas industry, and is primarily engaged in the gathering, processing, transportation, storage, and distribution of natural gas in the United States (Exh. AG-1-2(1)

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1 NEGC filed for approval of tariffs M.D.P.U. No. 1002B and No. 1003A through No. 1024A.

2 Citrus serves as the holding company for Florida Gas (Exh. AG-1-2(1) at 146).

at 5). Southern Union operates in three business segments: transportation and storage; gathering and processing; and distribution (Exh. AG-1-2(1) at 5). Its transportation and storage operations are conducted through its 99 percent partnership interest in Panhandle Eastern Pipe Line Company, LP ("PEPL") and its interest in Florida Gas Transmission Company, LLC ("Florida Gas") through Citrus Corporation ("Citrus") (Exh. AG-1-2(1) at 5).[2] PEPL operates, in conjunction with Trunkline Gas Company, LLC, and Sea Robin Pipeline Company, LLC, an extensive natural gas open-access interstate pipeline network (Exh. AG-1-2(1) at 6). Southern Union holds, through a series of intermediate subsidiaries, a 50 percent equity interest in Citrus, with the remaining 50 percent held by El Paso Citrus Holdings, which is a wholly owned subsidiary of El Paso Corporation ("El Paso") (Exh. AG-1-2(1) at 146). Southern Union's gathering and processing operations are conducted through Southern Union Gas Services (Exh. AG-1-2(1) at 10). Southern Union's distribution operations are conducted through NEGC and its Missouri Gas Energy division ("Missouri Gas") (Exhs. AG-1-2(1) at 13; AG-1-98, Att.). Missouri Gas provides gas service to approximately 550,000 customers in Missouri, and is subject to regulation by the Missouri Public Service Commission (Exhs. AG-1-2(1) at 13; AG-1-98, Att.). PEI Corporation ("PEI") is a wholly owned subsidiary of Southern Union that has ownership interests in two Pennsylvania electric power plants (Exh. AG-1-2(1) at 6). New England Gas Appliance Company ("NEG Appliance") is a wholly owned subsidiary of Southern Union that provides

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2 Citrus serves as the holding company for Florida Gas (Exh. AG-1-2(1) at 146).

appliance rentals and related maintenance and repair services to residential and C&I customers, primarily in NEGC's service area (Exhs. NEGC-JMS-1, at 12; AG-21-2).

On September 17, 2010, the Attorney General filed a notice of intervention pursuant to G.L. c. 12, § 11E. On October 22, 2010, the Department granted intervenor status to the Massachusetts Department of Energy Resources ("DOER"), Environment Northeast ("ENE"), and the Low-Income Weatherization and Fuel Assistance Program Network and Massachusetts Energy Directors Association ("Network"). Also on October 22, 2010, the Department granted limited participant status to NSTAR Gas Company.

Pursuant to notice duly issued, the Department held two public hearings: (1) in North Attleboro on October 21, 2010; and (2) in Fall River on October 25, 2010. The Department held eight days of evidentiary hearings from December 6, 2010, to December 17, 2010. The Network submitted its initial brief on January 19, 2011. The Attorney General, DOER, and ENE submitted initial briefs on January 20, 2011. NEGC submitted its initial brief on February 3, 2011. The Attorney General, ENE, and the Network submitted reply briefs on February 10, 2011. The Company submitted a reply brief on February 17, 2011. The evidentiary record consists of 758 exhibits and 94 replies to record requests.

In support of its filing, NEGC sponsored the testimony of seven witnesses: (1) David L. Black, chief operating officer for NEGC; (2) Robert Jefferson Hack, chief operating officer for Missouri Gas; (3) Frank J. Hanley, principal and director of AUS Consultants; (4) David A. Heintz, assistant vice president at Concentric Energy Advisors ("Concentric"); (5) James D. Simpson, vice president at Concentric; (6) Janet M. Simpson, partner in Dively and Associates, PLLC; and (7) James M. Sweeney, director of operations for NEGC.[3] The Attorney General sponsored the testimony of: (1) David E. Dismukes, consulting economist with the Acadian Consulting Group; (2) David J. Effron, an independent consultant; (3) Donna Ramas, senior regulatory analyst at Larkin & Associates, PLLC; (4) Lee Smith, managing consultant and senior economist at La Capra Associates; and (5) J. Randall Woolridge, of the Pennsylvania State University where he serves as (1) professor of finance, and (2) Goldman, Sachs & Co. and Frank P. Smeal endowed university fellow in business administration.[4]

B. Motion to Strike

1. Introduction

On February 25, 2011, the Attorney General submitted a motion to strike certain items from the evidentiary record in this proceeding pursuant to 220 C.M.R. §§ 1.04(5) and 1.11(7), (8) ("Motion to Strike"). Specifically, the Attorney General seeks to strike the following information from the Company's supplemental responses filed with NEGC's reply

3 The following individuals did not testify at evidentiary hearings and, instead, provided responses to information requests on behalf of NEGC and submitted sworn affidavits attesting to the veracity of the testimony: (1) James Carey; (2) Lucy LaForce; and (3) Michael J. McLaughlin.

4 On October 27, 2010, the Department approved the Attorney General's retention of experts or consultants, to assist in her representing consumer interests in this case, chargeable to the Company at a cost not to exceed $150,000. D.P.U. 10-114, Order on Attorney General's Notice of Retention of Experts and Consultants (October 27, 2010). The rate recovery of these costs by the Company is addressed in Section V.P., below.

brief on February 17, 2011: (1) Exhibit AG-9-20, 2nd Supp.[5] and the related $38,353 referenced in Exh. NEGC-JMS-1, Sch. G-8 (Rev.); and (2) $8,250 referenced in Exh. DPU-NEGC 5-8, Supp. Att. A[6] (Motion to Strike at 1, 7). Exhibit AG-9-20 and the supplemental responses contain information relating to NEGC's outside services and contract employees, while Exhibit DPU-NEGC-5-8 and its supplemental response summarize consultant costs incurred by the Attorney General.[7] NEGC submitted an opposition to the Motion to Strike on March 4, 2011 ("Opposition to Motion to Strike"). No other party commented on the Motion to Strike.

2. Positions of the Parties

a. Attorney General

The Attorney General asserts that the information submitted by the Company with its reply brief consists of extra-record evidence because the information was neither provided during the hearings nor accompanied by a motion to reopen the record to admit the post-hearing information (Motion to Strike at 5). With respect to Exhibit AG-9-20, 2nd Supp.,

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5 Exhibit AG-9-20 is the Company's response to information request AG-9-20. During the course of the proceeding, NEGC provided two separate supplemental responses to this information request.

6 Exhibit DPU-NEGC-5-8 is the Company's response to information request DPU-NEGC-5-8. During the course of the proceeding, NEGC provided a supplemental response to this information request.

7 Pursuant to G.L. c. 12, § 11E(b), the Attorney General may retain an expert or consultant to assist in proceedings before the Department. Absent a showing that the costs proposed to be expended on such expert or consultant are unnecessary or unreasonable, the expenditure shall be approved by the Department. G.L. c. 12, § 11E(b). The Attorney General recovers these costs from the company, which then passes such costs on to ratepayers. G.L. c. 12, § 11E(b).

the Attorney General asserts that NEGC has submitted new information that should have been provided as part of its case in chief or at some point prior to the close of the record (Motion to Strike at 4). The Attorney General acknowledges that the Department allows supplemental information to be submitted with a reply brief, but asserts that such supplemental information must be non-controversial in nature (Motion to Strike at 4-5). The Attorney General maintains that by filing new information with its reply brief, the Company has deprived the Attorney General and other intervenors of their due process rights because there is no opportunity to cross-examine the Company regarding the information (Motion to Strike at 5).

With respect to Exhibit DPU-NEGC-5-8 Supp., Att. A, the Attorney General accepts the bulk of the response as an appropriate and acceptable update to rate case expense (Motion to Strike at 7). Nonetheless, she asserts that two entries totaling $8,250 are for consulting services provided to the Attorney General in another proceeding (i.e., D.P.U. 10-62[8]) and, thus, should be stricken from the record in this proceeding (Motion to Strike at 7).

b. Company

NEGC maintains that the Motion to Strike should be denied for two reasons. First, the Company asserts that it has a continuing duty to amend earlier responses to discovery if the information contained therein is incorrect or incomplete when made or is no longer true or complete (Opposition to Motion to Strike at 1). The Company asserts that in reviewing the

[8] Docket D.P.U. 10-62 is a generic investigation by the Department into the ratemaking treatment of margins generated by local gas distribution companies from interruptible transportation, capacity release, off-system sales, interruptible sales, portfolio management and optimization agreements, and related transactions. Margin Sharing, D.P.U. 10-62, Vote and Order Opening Investigation (June 23, 2010).

issues raised by the Attorney General in her reply brief concerning Exhibits AG-9-20 and AG-9-20 Supp., NEGC determined that while the information was accurate or correct at the time the Company submitted the Exhibits, it was no longer factually complete or correct (Opposition to Motion to Strike at 3). Thus, the Company contends that there was a need and obligation to correct the record (Opposition to Motion to Strike at 3).

Second, the Company argues that it appropriately included additional information to resolve issues raised for the first time on brief by the Attorney General (Opposition to Motion to Strike at 1). NEGC argues that, in her reply brief, the Attorney General mischaracterized evidence provided during the course of the proceeding regarding certain employee expenses (Opposition to Motion to Strike at 4-5). NEGC contends that, as a result, it provided updated information to ensure that actual and correct information was placed before the Department (Opposition to Motion to Strike at 4-6).

In response to the Attorney General's argument that the supplemental information was not accompanied by a motion to reopen the record, the Company asks that should we determine such a motion is required, the Department treat the Company's Opposition to Motion to Strike as the required motion to reopen the record (Opposition to Motion to Strike at 3, citing Motion to Strike at 5). The Company does not comment on the Attorney General's request to strike two entries from Exhibit DPU-NEGC-5-8 Supp., Att. A.

3. 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. Argument and comment filed on brief are not evidence in a case, as there is no opportunity for cross-examination of such comments or for provision of rebuttal testimony and evidence. A party's presentation of extra-record evidence to the fact-finding 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. Boston Gas Company, D.P.U. 88-67 (Phase II) at 7 (1989). Our regulations also provide that no person may present additional evidence after having rested except upon motion and a showing of good cause. 220 C.M.R. § 1.11(8). 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. 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. Bay State Gas Company, D.P.U. 89-81, at 45 (1989).

In this case, the Company submitted Exhibit AG-9-20 Supp. containing invoices relating to contract employees, on December 16, 2010, which was prior to the conclusion of hearings. In Exhibit AG-9-20 Supp., the Company referenced the $38,353 that the Attorney General seeks to strike, and NEGC specifically stated that recognizing the annualized level of this cost requires an adjustment to increase the Company's test year expense by $38,353. By contrast, Exhibit AG-9-20 2nd Supp. focuses on an explanation for several of the invoices provided in Exhibit AG-9-20 Supp. Moreover, Exhibit AG-9-20 2nd Supp. does not reference the $38,353 amount but rather references the same cost as a rounded number (i.e., $35,000). In addition, NEGC presented testimony on the evidence provided in Exhibit AG-9-20 Supp.

during its oral rebuttal testimony on December 17, 2010 (Tr. 8, at 1058). The Attorney General and other intervenors could have sought to cross-examine on Exhibit AG-9-20 Supp., and they were expressly given the opportunity to conduct cross-examination on the oral testimony (Tr. 8, at 1066). The Attorney General, however, declined to conduct cross-examination of this evidence (Tr. 8, at 1066-1076). Based on these circumstances, we determine that the amount of $38,353 that the Attorney General seeks to strike from the record was placed into the record before the end of hearings. In addition, based on the specific circumstances of this case, we determine that it was not untimely and was appropriate for the Company to submit supplemental evidence to update the information in Exh. AG-9-20 Supp., to ensure that the record contained accurate information. Further, because the Attorney General and the other intervenors had an opportunity to conduct cross-examination on the actual invoices, which were provided in Exhibit AG-9-20 Supp., there was no violation of the parties' due process rights.[9]

The Attorney General also asks that the Department strike $8,250 referenced in Exh. DPU-NEGC 5-8 Supp., Att. A, because it refers to invoices for Attorney General consultants in a separately docketed matter, i.e., D.P.U. 10-62 (Motion to Strike at 1, 7). The Company's initial response to information request DPU-NEGC-5-8 was submitted on

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[9] The Attorney General asserts that Exhibit AG-9-20 2nd Supp. should also be rejected because it was not accompanied by an affidavit as required by Department regulations (Motion to Strike at 6 n.2, citing 220 C.M.R. § 1.10(4)). The response was a supplemental update to a previously attested-to response. In addition, as found above, the referenced $38,353 was in the record prior to the end of hearings, and, as such, the affidavit would simply be an unnecessary formality. Thus, for the limited purpose of this proceeding, we determine that an additional affidavit is not needed.

December 9, 2010. In that response, NEGC stated that it was providing information relating not only to the instant proceeding but also to D.P.U. 10-62, and, in fact, the initial response references $972 relating to D.P.U. 10-62 (Exh. DPU-NEGC-5-8 & Att. A). NEGC did not explain its rationale for submitting invoices relating to a separate Department matter (see Exh. DPU-NEGC-5-8). Nonetheless, the Company provided its initial response to Exhibit DPU-NEGC-5-8 prior to the conclusion of hearings and, thus, the Attorney General and other intervenors had an opportunity to cross-examine and determine the Company's rationale for including invoices pertaining to a different Department proceeding. Therefore, we find the parties' due process rights were not contravened and there is no need to strike the reference to $8,250 from the record.[10] Further, Exhibit DPU-NEGC-5-8 and the associated supplement both relate to invoices for services provided by the Attorney General's consultants.[11] In this Order, the Department approves the mechanism for NEGC to recover Attorney General consultant costs pursuant to G.L. c. 12, § 11E(b) (see Section V.P.3., below, recovery through local distribution adjustment factor ("LDAF")). In this proceeding, however, the Company does not seek recovery of any of the Attorney General's consultant costs. Instead, these costs will be recovered through the LDAF, and in the course of the Company's LDAF filings the Attorney General can argue the appropriateness of the recovery

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10 The Department does not rely on these invoices pertaining to D.P.U. 10-62 in deciding any issues in this case.

11 In appears that NEGC is tracking all invoices received from the Attorney General pursuant to G.L. c. 12, § 11E(b) in one spreadsheet (see Exh. DPU-NEGC-5-8).

of any specific costs, including the $8,250 in expenses related to D.P.U. 10-62. Accordingly, based on the above, the Department denies the Attorney General's Motion to Strike.

The Department takes extremely seriously the requirement that our decisions be based on record evidence. G.L. c. 30A, § 11(4). That record must consist of evidence properly before the Department. In this regard, the Department rigorously evaluates all motions to strike extra-record evidence. See, e.g., Payphone Inc., D.P.U. 90-177, at 3-5 (1991); The Berkshire Gas Company, D.P.U. 90-121, at 12-16 (1990); Hull Municipal Light Plant, D.P.U. 87-19-A at 5-8 (1990). Also, the Department on its own has taken steps to guard against a party's presentation of extra-record evidence. See, e.g., Boston Edison Company, D.P.U. 90-335, at 7-9 (1992).

However, in this case we observe that the Attorney General appears to have reacted to additional information accompanying the Company's reply brief without fully considering the issues. As we stated above, the material was (1) in the record before the end of hearings (Exh. AG-9-20 Supp.); and (2) an update to purely informational cost data (Exh. DPU-NEGC-5-8 Supp.), with appropriateness of the costs to be reviewed in a separate proceeding. We urge parties to carefully evaluate the grounds for a motion to strike before deciding to file.

II. REVENUE DECOUPLING

A. Introduction

In Investigation into Rate Structures that will Promote Efficient Deployment of Demand Resources, D.P.U. 07-50 (2007), the Department investigated the use of an RDM as a means to better align gas and electric distribution companies' financial interests with policy objectives regarding the deployment of demand resources,[12] while ensuring that the companies are not financially harmed by increased use of demand resources. D.P.U. 07-50, at 1, 11. Decoupling mechanisms sever the link between a company's revenues and sales through a periodic reconciliation of the actual revenue that a company bills to its ratepayers with a specified target revenue level. Massachusetts Electric Company/Nantucket Electric Company, D.P.U. 09-39, at 7 (2009). In this proceeding, NEGC's proposed decoupling mechanism is based on the revenue-per-customer decoupling approach that the Department approved in Bay State Gas Company, D.P.U. 09-30 (2009), which is a full decoupling approach (Exh. NEGC-JDS-1, at 13). Under a full revenue decoupling approach, the mechanism makes no adjustments to allowed revenues for changes in sales from the effects of weather, economic factors, adoption of energy efficiency, or other influences. Boston Gas Company/Colonial Gas Company/Essex Gas Company, D.P.U. 10-55, at 17 (2010).[13]

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12 Demand resources are installed equipment, measures, or programs that reduce end-use demand for electricity or natural gas. Such measures include, but are not limited to, energy efficiency, demand response, and distributed resources. D.P.U. 07-50, at 1 n.1.

13 In D.P.U. 07-50-A, the Department considered two types of decoupling mechanisms: (1) a full decoupling mechanism, under which a company would use its actual revenue collected from ratepayers to reconcile against the target revenue level; and (2) a partial decoupling mechanism, under which a company would adjust its actual revenue to take into account the effect of factors such as weather and the economy. The Department concluded that, in principle, both types of decoupling mechanisms would remove the financial disincentive that distribution companies currently face regarding the deployment of demand resources because, under both approaches, companies' revenue would be decoupled from a reduction in sales that result from such deployment. D.P.U. 07-50-A at 30-31. The Department concluded, however, that the

The Company states that the core elements of its proposed RDM are similar to the core elements approved by the Department in D.P.U. 09-30 and D.P.U. 10-55 (Exhs. NEGC-JDS-1, at 13; DPU-NEGC-2-27). The components of NEGC's proposed RDM are described below.

B. Company's Proposal

1. Introduction

NEGC is proposing an RDM that reconciles for each peak and off-peak season the difference between the Company's actual peak and off-peak billed distribution revenue-per-customer, by customer group, and a revenue-per-customer benchmark for each customer group (Exhs. NEGC-JDS-1, at 13; DPU-NEGC-2-27).[14] The Company initially proposed to implement the RDM through a provision in its local distribution adjustment clause ("LDAC") tariff (Exhs. NEGC-JDS-1, at 17; NEGC-JDS-1-15, at 12-16).[15] During the proceeding, the Company modified its request and now proposes to implement the semi-annual

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administrative burden, complexity, and potential for manipulation and error inherent in implementing a partial decoupling approach outweigh its advantages relative to full decoupling. D.P.U. 07-50-A at 30-31.

14 The peak period is from November 1 through April 30 and the off-peak period is from May 1 through October 31 (Exhs. NEGC-JDS-1, at 14 n.17; NEGC-JDS-1-15, at 13).

15 NEGC's current LDAC establishes the procedures that allow the Company to adjust, on an annual basis, its rates to recover costs relating to (1) energy efficiency, (2) environmental, (3) residential assistance adjustment factor, and (4) pension and post-retirement benefits other than pension. The LDAC also sets the basis for the returns to firm ratepayers balancing penalties and a portion of non-core distribution margins allocated to firm distribution services. These eligible LDAC costs and credits are charged to ratepayers through the local distribution adjustment factor (Exh. NEGC-JDS-1-15, at 1, Proposed M.D.P.U. No. 1002B).

revenue decoupling adjustments through an RDM tariff that is separate from its LDAC tariff (Exhs. DPU-NEGC-2-20; DPU-NEGC-2-29, at 2). The costs established by the RDM tariff are, however, a component of the LDAF, which is set for each peak and off-peak period (Exhs. DPU-NEGC-2-20; DPU-NEGC-2-29, at 2; see also Exh. NEGC-JDS-1-15).

2. Revenue-Per-Customer Benchmark

The Company proposes to adopt a revenue-per-customer approach to revenue decoupling (Exhs. NEGC-JDS-1, at 13; DPU-NEGC-2-27, at 1; DPU-NEGC-2-28; DPU-NEGC-2-29, at 1).[16] NEGC proposes to establish benchmark revenues and rate year number of customers (Exh. DPU-NEGC-2-29, at 1). Pursuant to the Company's proposal, customers will be divided into three customer class groups: (1) residential heating customers (R-3, R-4, T-3, and T-4); (2) residential non-heating customers (R-1, R-2, T-1, and T-2); and (3) C&I customers (G-41, G-42, G-43, G-51, G-52, G-53, T-41, T-42, T-43, T-51, T-52, and T-53) (Exhs. NEGC-JDS-1, at 13-14; NEGC-JDS-1-15, at 13; DPU-NEGC-2-27).[17] Although the Company does not currently provide service to any interruptible service or special contract customers, NEGC proposes to exclude any future customers that fall into these categories from the RDM because these customers would operate under contract terms or other circumstances

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16 In a revenue-per-customer approach, a company determines a benchmark amount or target revenue-per-customer for each of its rate classes in a base rate proceeding, and the revenues it collects through its RDM will vary based on the number of customers it serves. See D.P.U. 07-50-A at 48-49, 85; D.P.U. 07-50, at 13-14.

17 See Section VII.E., for a description of each rate class.

that are inherently different from the Company's other C&I customers (Exhs. DPU-NEGC-2-29; DPU-NEGC-2-30; see also Exh. NEGC-JDS-1-15, at 13).[18]

NEGC states that the initial peak and off-peak revenue benchmarks will be set equal to base revenue requirements by rate group approved in this proceeding as determined by the Department and calculated in the Company's compliance filing (Exhs. NEGC-JDS-1, at 13, 15-16 n.18; DPU-NEGC-2-26). The revenue benchmarks for each rate group would then remain the same until new rates are authorized by the Department (Exhs. NEGC-JDS-1, at 13-14, 15-16 n.18; DPU-NEGC-2-26; DPU-NEGC-2-29, at 1).

3. Revenue Decoupling Adjustments

As noted earlier, NEGC revised its proposal during the proceeding and now proposes an RDM tariff that is separate from its LDAC tariff (Exhs. DPU-NEGC-2-20; DPU-NEGC-2-29, at 2). The Company's peak and off-peak RDM adjustments will be determined prior to the start of each season (Exhs. NEGC-JDS-1, at 15; DPU-NEGC-2-26, at 1; DPU-NEGC-2-29, at 2). First, NEGC will calculate the difference between the actual revenue-per-customer billed and the base revenue-per-customer benchmark for the three customer class groups for the recently completed peak or off-peak period (Exhs. NEGC-JDS-1, at 15; DPU-NEGC-2-14; DPU-NEGC-2-29, at 2). The difference for each customer class group is multiplied by the average number of existing customers billed in that season and for that group (Exhs. NEGC-JDS-1, at 15; DPU-NEGC-2-14;

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18 The Company does not have a gas lighting rate schedule or a separate street lighting rate class (Exhs. DPU-NEGC-2-29, at 1 nn.1-2; DPU-NEGC-2-30).

DPU-NEGC-2-29, at 2). Next, the sum of the resulting differences in revenues for the three customer class groups is added to the revenue decoupling reconciliation (Exhs. NEGC-JDS-1, at 15; DPU-NEGC-2-14; DPU-NEGC-2-29, at 2). The resulting total is then divided by the forecast throughput volume, inclusive of all firm sales and firm transportation throughput, for the upcoming peak or off-peak period to arrive at the applicable revenue decoupling adjustment unit charge (Exhs. NEGC-JDS-1, at 15; DPU-NEGC-2-14; DPU-NEGC-2-29, at 2).

The Company proposes that the revenue decoupling adjustment be applied to customer bills in the next corresponding season (i.e., the revenue decoupling adjustment for the peak season will be applied to customer bills in the next peak period and the revenue decoupling adjustment for the off-peak period will be applied to customer bills in the next off-peak period) (Exhs. NEGC-JDS-1, at 16; NEGC-JDS-1-15, at 14; DPU-NEGC-2-29, at 2). NEGC proposes to make its first revenue decoupling adjustment filing on August 1, 2011, in conjunction with its 2010/2011 LDAF filing, to adjust revenues from a portion of the preceding peak season (i.e., March and April 2011) (Exhs. NEGC-JDS-1, at 16; NEGC-JDS-1-4, at 1; DPU-NEGC-2-29, at 2).

4. Revenue Cap

Under the Company's proposal, the total peak or off-peak revenue decoupling rate adjustment may not exceed three percent of total revenues from firm sales and firm transportation throughput for the most recent corresponding peak or off-peak periods, with transportation revenues to be adjusted by imputing the Company's cost of gas charges for that period (Exhs. NEGC-JDS-1, at 17; DPU-NEGC-2-17; DPU-NEGC-2-29, at 3). To the extent that the application of the revenue cap results in a revenue decoupling rate adjustment that does not fully recover the calculated decoupling adjustment, the Company proposes to defer the difference and include it in the decoupling reconciliation for recovery in the subsequent year during the corresponding peak or off-peak period, with carrying costs at the Bank of America prime lending rate (Exhs. NEGC-JDS-1, at 17; DPU-NEGC-2-18; DPU-NEGC-2-29, at 3).

5. Revenue Decoupling Reconciliation Adjustment

NEGC states that the total revenue decoupling adjustment will be reconciled for variances between actual and projected sales (Exhs. NEGC-JDS-1, at 16; NEGC-JDS-1-15, at 14-15; DPU-NEGC-2-29, at 3). To accomplish this reconciliation, a revenue decoupling reconciliation adjustment will be calculated separately for each season and will be included in the revenue decoupling adjustment for the corresponding season in the following year (Exhs. NEGC-JDS-1-15, at 14; DPU-NEGC-2-29, at 3). The Company proposes to apply carrying costs to the average monthly balance of the decoupling reconciliation adjustment at the Bank of America prime lending rate (Exh. DPU-NEGC-2-29, at 3).

6. Treatment of New Customers

NEGC proposes to treat customer counts and revenues associated with new customers (i.e., new customer meters, services, and/or mains extension) outside of the RDM (Exhs. NEGC-JDS-1, at 14, 16; DPU-NEGC-2-15; DPU-NEGC-2-29, at 3). Specifically, NEGC proposes that, between the time new rates go into effect and the time rates are changed by the Department in a subsequent base rate proceeding, customer counts and customer revenues associated with new customers will be excluded from the calculation of the revenue decoupling adjustment (Exhs. NEGC-JDS-1, at 16; DPU-NEGC-2-15; DPU-NEGC-2-29, at 3). In this way, NEGC will be able to retain the incremental revenue generated from those new customers and, as such, maintain its incentive to promote residential conversions (Exh. DPU-NEGC-2-29, at 3). NEGC proposes to include the revenues and billing determinants associated with new customers into the customer class groups at the time of the Company's next general rate case (Exhs. NEGC-JDS-1, at 16; DPU-NEGC-2-15; DPU-NEGC-2-29, at 3). Under NEGC's proposal, the revenue decoupling adjustment will be charged or credited to these new customers through the LDAF in the same manner as for existing customers (Exhs. NEGC-JDS-1, at 14; DPU-NEGC-2-29, at 3).

7. Treatment of Non-Heating to Heating Conversions

NEGC proposes to retain the incremental revenues generated from existing customers converting from non-heating to heating service (Exhs. DPU-NEGC-2-27; DPU-NEGC-2-29, at 4). Specifically, the Company would include a residential non-heating customer in the residential non-heating customer class for the months that the customer is a non-heating customer and then, after conversion, would include that customer in the residential heating customer class for the months that the customer is a heating customer (Exhs. DPU-NEGC-2-27; DPU-NEGC-2-29, at 4).

C. Positions of the Parties

1. Attorney General

The Attorney General simply notes that the Company has proposed an RDM (Attorney General Brief at 49). She does not opine on the appropriateness or design of the proposed RDM (Attorney General Brief at 49).[19]

2. DOER

DOER asserts that the type of RDM proposed by NEGC fully decouples sales from revenues, and thus achieves the Department's objective of removing a principal obstacle to the adoption of cost-effective energy efficiency and demand response programs (DOER Brief at 3). Nonetheless, DOER disagrees with the Company's proposed treatment of incremental revenues received from existing residential non-heating customers that convert to heating (DOER Brief at 3). DOER argues that the Department should reject NEGC's proposal to retain these incremental revenues (DOER Brief at 3). DOER contends that there is no justification for retaining the revenues from residential conversions, particularly when revenues from C&I customers adding gas-powered equipment are reconciled through the RDM and the benefits of converting for both residential and C&I customers are similar (DOER Brief at 3-4). DOER asserts that, with the exception of the treatment of incremental revenues relating to heating conversions, the proposed RDM is consistent with past Department Orders and should be approved (DOER Brief at 3).

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[19] The Attorney General's position regarding the impact a Department-approved RDM would have on the Company's return on equity is discussed in Section VI.F.2., below.

3. ENE

ENE asserts that the Company's proposed RDM closely adheres to the Department's directives in D.P.U 07-50 and achieves the policy goal of aligning the Company's financial incentives with the policy of investing in all cost-effective energy efficiency and demand-side resources (ENE Brief at 7). ENE also asserts that the proposed RDM closely tracks the decoupling proposals previously approved by the Department (ENE Brief at 7-8, citing D.P.U. 10-55; D.P.U. 09-39; D.P.U. 09-30). ENE states that the Company's proposal to include the revenues and billing determinants associated with new customer class groups at the time of the Company's next general rate case is consistent with the Department's previous Orders (ENE Brief at 7, citing D.P.U. 10-55, at 45; D.P.U. 09-30, at 98-101). ENE asserts that the Company's treatment of non-heating to heating conversion customers is appropriate and consistent with the method previously approved by the Department (ENE Brief at 7, citing D.P.U. 10-55). Accordingly, ENE recommends approval of the Company's decoupling proposal (ENE Brief at 8).

4. Company

The Company asserts that its proposed RDM is consistent with the Department's policy determination in D.P.U. 07-50-A as well as the Department's decisions in D.P.U. 09-30, D.P.U. 09-39, and D.P.U. 10-55 (Company Brief at 71). NEGC also contends that the Company's proposal to retain the incremental revenue associated with residential non-heating customers that convert to residential heating is consistent with Department precedent (Company Brief at 74, citing D.P.U. 10-55; Exhs. DPU-NEGC-2-27; DPU-NEGC-2-29).

NEGC argues that its treatment of incremental revenues associated with residential non-heating customers that convert to residential heating is intended to allow the Company to maintain its incentive to promote residential conversions, which will provide substantial benefits to all customers in setting rates in the future (Company Brief at 74). In addition, the Company asserts that its proposal will avoid the significant administrative complications associated with recording and reporting the incremental revenues for residential non-heating customers that convert to heating (Company Brief at 74).

The Company disagrees with DOER's assertion that C&I customers that add heating equipment are treated differently from residential customers that add heating equipment (Company Brief at 74). The Company argues that its proposal, in fact, treats all residential and C&I customers that add heating equipment identically, i.e., the converting customer would be reclassified, if appropriate, to a different rate class and billed at the rates of the new rate class (Company Brief at 74-75). Nonetheless, NEGC maintains that the effects on RDM calculations of that reclassification differ between residential and C&I customers (Company Brief at 75). Specifically, for residential customers, the conversion of a residential non-heating customer would represent a decrease in the number of customers in the residential non-heating RDM customer group and an increase in the number of customers in the residential heating RDM customer group, while if a C&I customer added heating equipment there would be no change in the number of customers in the C&I RDM customer group because there is only one C&I RDM customer group (Company Brief at 75).

D. Analysis and Findings

1. Introduction

The Department's authority to adopt decoupled rates arises from our delegated authority under G.L. c. 164, § 94 to prescribe the rates, prices, and charges that utilities may collect. D.P.U. 07-50-B at 26, citing Boston Edison Co. v. City of Boston, 390 Mass. 772, 774 (1984). In determining the propriety of such rates, the Massachusetts Supreme Judicial Court has affirmed that the Department must find that they are just and reasonable. See Attorney General v. Department of Telecommunications and Energy, 438 Mass. 256, 264 n.13 (2002). Therefore, in reviewing the Company's proposed RDM, the Department must find (1) that its operation will result in rates that are just and reasonable, and (2) that its design is consistent with the policy framework established in D.P.U. 07-50-A and D.P.U. 07-50-B.

In D.P.U. 07-50-A at 24, the Department found that promoting the implementation of all cost-effective demand resources is a high priority. To realize the full potential of demand resources, we stated that it is essential to leverage the distribution companies' relationships with customers as well as with any other entities that will be engaged in the development and deployment of such demand resources. D.P.U. 07-50-A at 25. In considering the various ratemaking alternatives that would promote the implementation of all cost-effective demand resources, the Department concluded that a full decoupling mechanism best meets the objectives of: (1) aligning the financial interests of the companies with policy objectives regarding the efficient deployment of demand resources; and (2) ensuring that the companies are not harmed by decreases in sales associated with any increased use of demand resources. D.P.U. 07-50-A at 31-32. The Department noted that the conclusions reached in D.P.U. 07-50-A represented general statements of policy. D.P.U. 07-50-B at 23-29. The Department also noted that issues such as the equity associated with and appropriateness of specific revenue recovery proposals would be addressed based on the evidence and argument presented in the adjudication of a distribution company's individual decoupling proposal. D.P.U. 07-50-B at 29.

As described above, NEGC proposes to implement revenue decoupling using a full decoupling approach with a three percent revenue cap in each season (i.e., peak and off-peak) on the increase to rates from the operation of the RDM (Exhs. NEGC-JDS-1, at 13, 17; DPU-NEGC-2-29). DOER raises concerns relating to the Company's proposed treatment of non-heating to heating conversions in the proposed RDM (DOER Brief at 3-4). The proposed RDM is addressed below. The Department will address issues related to the impact of revenue decoupling on the Company's ROE in Section VI.F.4., below.

2. Revenue-Per-Customer Benchmark

NEGC proposes to implement a RDM using a revenue-per-customer approach (Exhs. NEGC-JDS-1, at 13; DPU-NEGC-2-29, at 1). The Company's proposed revenue-per-customer approach is consistent with the method endorsed by the Department in D.P.U. 07-50-A at 48-50 and approved by the Department in D.P.U. 09-30, at 89-91. Accordingly, we accept the Company's proposed revenue-per-customer approach as the framework for the Company's RDM.

3. Revenue Decoupling Adjustments

In D.P.U. 07-50-A at 55, the Department stated that each distribution company shall propose a base rate adjustment mechanism that reconciles target to actual revenues for each rate class. The Department has determined that given the similar cost and load characteristics of the residential customer classes within the heating and non-heating rate classes, and for rate simplicity, it is appropriate to establish one benchmark base revenue-per-customer that is applicable to the non-heating rate classes and another benchmark base revenue-per-customer that is applicable to the heating classes. D.P.U. 10-55, at 41; D.P.U. 09-30, at 90. For these same reasons, the Department approves NEGC's proposal to adopt one base revenue-per-customer benchmark for its residential heating customer class group and one for its residential non-heating customer class group.

Similarly, the Department has determined that potential migrations from one C&I rate class to another could cause class-specific revenue-per-customer benchmarks to be unrepresentative of the cost to serve that class and provide perverse incentives to the Company to promote increased throughput because the base revenue-per-customer is higher for the larger C&I rate classes. Thus, the Department has accepted proposals to aggregate C&I rate classes into one group and develop one base revenue-per-customer benchmark for that group. D.P.U. 10-55, at 41; D.P.U. 09-30, at 90-91. For this same reason, the Department approves NEGC's proposal to develop one base revenue-per-customer benchmark for its C&I customer class group.

In addition, the Company's proposal to implement peak season and off-peak season revenue decoupling adjustments is consistent with the Company's existing method of reconciliations through its LDAF and its cost of gas adjustment clause ("CGAC") (Exh. NEGC-JDS-1, at 16). It is also consistent with the seasonal revenue decoupling adjustments approved for other Massachusetts local gas distribution companies ("LDCs"). D.P.U. 10-55, at 41-42; D.P.U. 09-30, at 91. Accordingly, we approve the Company's proposal to use peak and off-peak season base revenue-per-customer benchmarks in its decoupling revenue adjustments.

4. Revenue Cap

Under the Company's proposal, the total peak or off-peak revenue decoupling rate adjustment may not exceed three percent of total revenues from firm sales and firm transportation throughput for the most recent peak or off-peak periods, with transportation revenues to be adjusted by imputing the Company's cost of gas charges for the period (Exhs. NEGC-JDS-1, at 17; DPU-NEGC-2-17; DPU-NEGC-2-29). Any revenue amounts that exceed the cap would be deferred for recovery in the subsequent same season, with the deferred balance accruing with interest at the Bank of America prime lending rate (Exhs. NEGC-JDS-1, at 17; DPU-NEGC-2-18).

The Department finds that the application of a revenue cap is consistent with the Department's directive in D.P.U. 07-50, at 12, that a RDM must "be consistent with Department precedent related to rate continuity, fairness, and earnings stability." If a cap is not applied, large revenue decoupling adjustments could occur, thereby violating the

Department's rate structure goal of rate continuity. See D.P.U. 10-55, at 43; D.P.U. 09-39, at 85-86; D.P.U. 09-30, at 114; D.P.U. 08-35, at 221; Massachusetts Electric Company, D.P.U. 92-78, at 116 (1992); D.P.U. 88-67 (Phase I) at 201.

In determining the appropriate cap on the total amount of revenue decoupling adjustments, the Department must balance its goal of promoting the deployment of demand resources with its rate structure goals including rate continuity. D.P.U. 09-39, at 87; D.P.U. 09-30, at 116; see D.P.U. 07-50-A, at 24; Bay State Gas Company, D.T.E. 05-27, at 305 (2005); D.T.E. 02-24/25, at 252; D.P.U. 88-67, at 201. Revenue decoupling adjustments should be large enough to avoid intergenerational inequity and unfairness in rates but small enough to preserve continuity in rates. D.P.U. 10-55, at 43; D.P.U. 09-39, at 87. In balancing the concerns, the Department has previously imposed a three-percent cap on annual revenue decoupling adjustments. D.P.U. 10-55, at 43; D.P.U. 09-39, at 87; D.P.U. 09-30, at 116-117. The same rationale applies here. Thus, we find that the Company's proposed three-percent cap, based on total concurrent peak or off-peak season actual base distribution, LDAC, and gas commodity revenues, representing the maximum amount of base distribution revenue decoupling adjustments for the upcoming peak or off-peak period, strikes an appropriate balance between promoting the deployment of demand resources and rate structure goals including rate continuity. Therefore, the Department approves NEGC's three-percent revenue cap.

Consistent with Department precedent, for NEGC's RDM, any unrecovered revenue decoupling adjustment that is above this three-percent cap shall be deferred for recovery in the next corresponding period, with carrying charges applied at the Bank of America prime lending rate. See D.P.U. 10-55, at 44; D.P.U. 09-39, at 87-88; D.P.U. 09-30, at 116-117. Because the revenue decoupling adjustments are reconciled from one season to another, the Department finds that it is appropriate to continually evaluate and monitor changes in the market that could violate our existing ratemaking goals and render a three-percent revenue cap inappropriate. Accordingly, the Department will review, reevaluate, and modify the revenue cap, as necessary, during the Company's peak and off-peak revenue decoupling adjustment filings. See D.P.U. 10-55, at 44; D.P.U. 09-30, at 117.

5. Revenue Decoupling Reconciliation Adjustment

The Department finds that the Company's proposal to reconcile variances between actual and projected sales separately for each season and accrue interest on the monthly balance at the Bank of American prime lending rate is consistent with the revenue decoupling reconciliation method approved in D.P.U 10-55 and D.P.U. 09-30, and is consistent with the framework established in D.P.U. 07-50-A and D.P.U. 07-50-B (see Exhs. NEGC-JDS-1, at 17; NEGC-JDS-1-15, at 14-15; DPU-NEGC-2-29, at 3). Further, no party opposed the Company's proposed method to reconcile variances between actual and projected sales. Therefore, the Department approves the Company's proposed method to reconcile variances between actual and projected sales.

6. Treatment of New Customers

The Company proposes to exclude customer counts and customer revenues associated with new customers (i.e., those customers that are connected to the Company's system after the test year), from the calculation of the revenue decoupling adjustment until the Company's next general rate case (Exhs. NEGC-JDS-1, at 14; NEGC-JDS-1, at 16; DPU-NEGC-2-15; DPU-NEGC-2-29, at 3). Long-standing Department precedent regarding the ratemaking treatment of incremental revenues from new customers after rates have been set in a base rate proceeding allows a company to retain those incremental revenues until that company's next general rate case. D.P.U. 10-55, at 45-46; D.P.U. 09-30, at 94 & n.50; D.T.E. 05-27, at 75, 79, 80; Boston Gas Company, D.T.E. 03-40, at 48 (2003); D.P.U. 88-67 (Phase I) at 282-284; Boston Gas Company, D.P.U. 89-180, at 16-17 (1990). The Department determined that post-decoupling, it is appropriate to permit a gas utility to retain incremental revenues from new customers added after the test year in order to preserve the incentive to the gas utility to add new customers, which should, in the long run, reduce a company's average cost of distribution service. See D.P.U. 10-55, at 45-46; D.P.U. 09-30, at 98-99.[20]

Thus, consistent with Department precedent, we will permit NEGC to retain the incremental revenues from new customers until its next rate case by not including new customers in the reconciliation of the RDM. The Company is directed to separately track the usage of new customers in the peak and off-peak seasons, as well as the cost to connect new

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[20] Regarding the addition of customers, the Department has found that a gas utility need not serve new customers in circumstances where the addition of new customers would raise the cost of gas service for existing firm ratepayers. D.T.E. 05-27, at 75, 79-80, citing D.T.E. 03-40, at 48, D.P.U. 88-67 (Phase I) at 282-284. The Department stated that existing customers receive benefits whenever the return on the incremental rate base exceeds the company's overall rate of return. D.T.E. 05-27, at 75, citing D.P.U. 89-180, at 16-17.

customers by rate class,[21] and report such information as part of its seasonal revenue decoupling adjustment filing. See D.P.U. 10-55, at 46-47; D.P.U. 09-30, at 100-101.

7. Treatment of Non-Heating to Heating Conversions

NEGC proposes that when existing residential customers convert from non-heating to heating services they be counted in the RDM as heating customers (Exhs. NEGC-JDS-1, at 14, 16; DPU-NEGC-2-15; DPU-NEGC-2-29, at 3). In other words, NEGC would retain the heating base revenue-per-customer, rather than the non-heating base revenue-per-customer that it would have retained if the customer had not converted to heating services (Exhs. DPU-NEGC-2-27; DPU-NEGC-2-29, at 4). NEGC argues that such treatment is necessary to maintain its incentive to promote residential conversions, which will provide substantial benefits to all customers in setting rates in the future (Company Brief at 74).

DOER recommends that the Department reject the Company's proposal to retain incremental revenues associated with the conversion of existing customers from non-heating to heating service (DOER Brief at 3). DOER argues that this part of the RDM plan converts the decoupling mechanism into a partial mechanism that would operate only to increase the revenues received by the Company (DOER Brief at 3). Since the Department has implemented decoupling, DOER has consistently urged the Department to reject gas companies' proposals to retain incremental revenues associated with the conversion of existing customers from non-heating to heating service. D.P.U. 10-55, at 29; D.P.U. 09-30, at 67. Here, DOER has

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[21] To the extent NEGC does not currently have a system to track the costs to connect new customers by rate class, we direct the Company to develop such a system.

not brought to light any new argument or reasoning in support of its position. Thus, we find no basis on which to alter our findings and, we confirm, as noted in Section II.D.6., above, that long-standing Department precedent regarding the ratemaking treatment of additional revenues from new customers after rates have been set allows the Company to retain those revenues. D.P.U. 09-30, at 94 n.50, citing D.T.E. 05-27, at 75, 79, 80; D.T.E. 03-40, at 48; D.P.U. 88-67 (Phase I) at 282-284; D.P.U. 89-180, at 16-17. The Department has found that continuation of our long-standing ratemaking treatment will ensure both that the benefits of the conversions ultimately flow to ratepayers in terms of lower rates and that the public will gain the environmental benefits of conversions to gas for heating purposes. D.P.U. 10-55, at 49-50. With respect to treatment of the incremental revenues, we find no reason to distinguish the treatment for new customers from the treatment for customers that convert from the non-heating residential rate to the heating residential rate. D.P.U. 10-55, at 50. Thus, we approve NEGC's proposal to keep the incremental revenues (i.e., the difference in revenue-per-customer between heating and non-heating target revenue) associated with non-heating to heating service customer conversions.

In addition, consistent with the Department's goal of promoting the implementation of all cost-effective demand resources, the Department seeks to develop a reliable and consistent record with respect to: (1) the number of customers migrating from one rate class to another rate class; (2) the cost to convert customers from residential non-heating service to heating service; (3) the reduction in the number of existing customers by rate classes; (4) the addition of new customers by rate classes; and (5) the impact on customers' consumption behavior under revenue decoupling specific to NEGC. Thus, the Company must provide such information in each semi-annual revenue decoupling adjustment filing.

8. Review of Revenue Decoupling Mechanism

The Company is directed to provide in each of its peak and off-peak revenue decoupling adjustment filings, a consistent and on-going record of all relevant information, so that the Department can closely monitor the implementation of NEGC's RDM. To the extent that the implementation of revenue decoupling may result in undesirable or unintended consequences that could result in unjust and unreasonable rates, then the Department, on its own motion pursuant to G.L. c. 164, § 93, and its general supervisory authority over LDCs pursuant G.L. c. 164, § 76, may determine it necessary to investigate the propriety of such existing rates.

9. Revenue Decoupling Recovery Adjustment

As noted above, the Company initially proposed to implement the RDM through a provision in its LDAC tariff but modified its request during the proceeding and now proposes a separate RDM tariff, in which the revenue decoupling recovery will be submitted in conjunction with the Company's LDAC filings (Exhs. NEGC-JDS-1, at 17; NEGC-JDS-1-15, at 12-16; DPU-NEGC-2-20; DPU-NEGC-2-29, at 2). As discussed above, the Company will provide in each of its peak and off-peak revenue decoupling adjustment filings certain information so that the Department can closely monitor the implementation of the revenue decoupling adjustment. As such, we find that the Company's revised proposal to have a separate decoupling tariff is consistent with Department directives. See D.P.U. 10-55, at 52-53.

In regards to the Company's proposal to include the revenue requirement established by the RDM tariff as a component of the LDAF revenue requirement, the Department finds that the revenue requirement established by the RDM tariff is intended to adjust the revenue requirement that the Company bills for distribution service in order to reconcile actual billed base revenues with benchmark base revenues. Therefore, we find that the RDM factor is properly a component of distribution rates. The LDAF recovers some cost components that are not specifically related to distribution service. As such, we reject the Company's proposal to include the revenue requirement established by the RDM as a component of the LDAF revenue requirement. Instead, the RDM factor should be included as a component of the variable distribution rates, with the RDM factor stated as a notation on each customer's bill. Accordingly, we direct the Company to remove any decoupling-related elements from its LDAC tariffs and submit, as part of its compliance filing, a separate RDM tariff, with appropriate formulas, definitions, and calculations, consistent with the Department's findings and directives in this Order.

Regarding the time frame for the Company to file its decoupling adjustments, we direct the Company to file its proposed decoupling adjustments at least 90 days prior to the effective dates of the November 1 peak period revenue decoupling adjustment and the May 1 off-peak period revenue decoupling adjustment.[22] This time frame will afford the Department and all interested parties sufficient time to review future proposed decoupling adjustments.

10. Conclusion

The Department finds that the Company's proposed decoupling mechanism is consistent with the policy framework established in D.P.U. 07-50-A and D.P.U. 07-50-B. The proposed decoupling mechanism appropriately aligns the financial interests of the Company with the efficient deployment of demand resources and will ensure that the Company is not harmed by decreases in sales associated with an increased use of demand resources. Further, we find that operation of the Company's proposed RDM will result in just and reasonable rates. Accordingly, NEGC's proposed RDM is approved.

III. TARGETED INFRASTRUCTURE RECOVERY FACTOR

A. Introduction

As of December 31, 2009, the Company had a total of 604.49 miles of mains[23] and 34,700 services[24] in its distribution system (Exhs. NEGC-JMSw-1, at 12, Table JMSw-1;

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22 We note that these filing deadlines are consistent with requirements for LDAF-related reconciliation filings.

23 This total includes: (1) 50.33 miles of non-cathodically protected (also referred to as "unprotected") bare steel mains; (2) 92.21 miles of cathodically protected bare steel mains; (3) 153.11 miles of cathodically protected coated steel mains; (4) 120.21 miles of small diameter (i.e., less than or equal to eight inches) cast iron and wrought iron mains; (5) 14.88 miles of large diameter (i.e., greater than eight inches) cast iron and wrought iron mains; and (6) 173.75 miles of plastic mains (Exhs. NEGC-JMSw-1, at 12; DPU-NEGC-3-23, Att.).

24 This total includes (1) 2,089 non-cathodically protected bare steel services, (2) 7,816 non-cathodically protected coated steel services, (3) 4,681 cathodically

DPU-NEGC-3-23, Att.). Starting in 2009, NEGC embarked on an accelerated replacement of its aged distribution infrastructure that targeted the replacement of non-cathodically protected steel mains and small diameter (i.e., eight inches or less) cast-iron and wrought iron mains at a pace of approximately seven miles per year, compared to its prior years' average replacement pace of 3.55 miles per year from 2004 through 2008, which is an increase of 3.45 miles per year or 97 percent (Exhs. NEGC-JMSw-1, at 10-11; NEGC-JDS-1-16, at 16; AG-4-45, Att.; AG-6-2; DPU-NEGC-3-24, Att.).[25] NEGC states that this seven-mile per-year pace of mains replacement targeting its leak-prone facilities would eliminate, over a 15-year period, 105 miles or approximately 50 percent of its inventory of bare steel and small diameter cast iron mains, excluding mains that may be appropriate for the installation of cathodic protection over the same period (Exh. NEGC-JMSw-1, at 11, 13; Tr. 2, at 182; Tr. 5, at 610-611, 617-618).[26]

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protected coated steel services, and (4) 20,114 plastic services (Exh. DPU-NEGC-3-23, Att.).

[25] For years 2005 through 2009, the Company's historical capital spending on bare steel and cast iron replacement was $1,503,564, $1,688,310, $1,584,330, $2,640,062, and $3,754,421, respectively (Exhs. NEGC-JDS-1-6; DPU-NEGC-3-35; RR-DPU-12). For the same period, the corresponding number of miles of bare steel and cast iron mains replaced or retired by the Company were 2.48 miles, 3.66 miles, 3.05 miles, 4.54 miles, and 7.22 miles, respectively (Exh. DPU-NEGC-3-24, Att.). The corresponding number of services replaced or retired for the same period were 42, 336, 249, 432, and 562 (Exh. DPU-NEGC-3-24, Att.).

[26] The Company's budgeted annual capital spending for recovery under its proposed TIRF is $4,450,000 in 2010, $3,172,900 in 2011, and $2,956,800 for years 2012 through 2014 (Exh. NEGC-1-9; Tr. 5, at 617; RR-DPU-37, Att. A, at 1). Regarding the relatively large budgeted amount of $4.45 million in 2010, as compared to the budgeted amounts for 2011 through 2014, the Company explained that this is due to a large

NEGC proposes to implement a rate mechanism to support its replacement program, referred to as TIRF, which adjusts the Company's rates annually to recover its capital investments on the replacement of leak-prone mains, services and associated facilities (Exhs. NEGC-JMSw-1, at 4; NEGC-JDS-1-15, at 17; Tr. 2, at 182).[27] The Company proposes to include in the TIRF the recovery of capital costs incurred in the replacement of non-cathodically protected steel mains and services and small diameter cast and wrought iron mains (Exhs. NEGC-JMSw-1, at 8-9; NEGC-JDS-1-15, at 16). NEGC claims that the replacement of non-cathodically protected steel mains and services and small diameter cast-iron mains poses the greatest operational challenge in its distribution system (Exh. NEGC-JMSw-1, at 8-9). The Company adds that the replacement of these facilities is a significant driver of O&M expense incurred in maintaining its distribution system (Exh. NEGC-JMSw-1, at 9).

The Company states that its proposed TIRF is designed to support its long-term strategy of infrastructure replacement without the impediment of current capital constraints (Exh. NEGC-JMSw-1, at 6). More specifically, NEGC emphasizes the need to maintain a

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project that involved the replacement of an 8,600-foot four-inch bare steel main by an eight-inch plastic pipe at Riverside Avenue, Somerset, to increase the pressure in the northern end of the town (Tr. 5, at 612-615, 683-684; RR-DPU-36, Att.; RR-AG-9, Att.). The Company reduced this 2010 budget estimate to $4.0 million based on its actual capital expenditures through November 2010 and an estimate of December 2010 costs (RR-AG-9).

27 The Company defined "TIRF" in two other ways: (1) "targeted infrastructure replacement factor" (Exhs. NEGC-JMSw-1, at 4; NEGC-JDS-1, at 19); and (2) "targeted infrastructure reinvestment factor" (Exh. NEGC-JDS-1-15, at 17). For consistency, we define TIRF here as "targeted infrastructure recovery factor" as shown in Record Request DPU-14, Attachment A at 17. See D.P.U. 10-55, at 67; D.P.U. 09-30, at 1.

pace of replacement that will result in a material reduction in the inventory of non-cathodically protected steel and small diameter cast iron facilities on a reasonable time frame (Exh. NEGC-JMSw-1, at 13). The Company reasons that without a more timely recovery of the revenue requirement associated with those investments, it would not be possible to maintain such a pace of facilities' replacement (Exh. NEGC-JMSw-1, at 13).

In addition, NEGC states that its proposed RDM, described in Section II.B., above, eliminates its ability to increase revenues through sales (Exh. NEGC-JDS-1, at 18). The Company argues that since the capital spending to replace bare steel and small diameter cast iron facilities represents a significant portion of its capital expenditures with no expected growth-related incremental revenues, the TIRF would provide the necessary revenues to finance such capital expenditures and avoid earnings' erosion (Exhs. NEGC-JDS-1, at 18; NEGC-JDS-1-5).

The Company states that its proposed TIRF is consistent with Department precedent, claiming that the Department has recognized that the replacement of aging infrastructure is appropriate and desirable from a public policy perspective given the potential benefits to public safety, service reliability, and the environment (Exh. NEGC-JMSw-1, at 4, 6, citing D.P.U. 09-30, at 133). The Company adds that its proposed TIRF is similar to the TIRF mechanism approved in D.P.U. 09-30 and the TIRF mechanism filed for approval by Boston

Gas Company, Colonial Gas Company, and Essex Gas Company, d/b/a National Grid ("National Grid") on April 16, 2010, in D.P.U. 10-55 (Exh. NEGC-JDS-1, at 18).[28]

To implement its proposed TIRF mechanism, the Company proposed to revise its existing LDAC tariff, adding a section entitled "Targeted Infrastructure Recovery Costs Allowable for LDAC" (Exh. NEGC-JDS-1-15). During the proceeding, the Company filed a revised LDAC tariff containing changes, among other things, relating to its proposed TIRF mechanism, assuming that the Department would not approve certain provisions that are not entirely in accord or consistent with the TIRF mechanism approved in D.P.U. 09-30 and in D.P.U. 10-55 (Tr. 2, at 208-220; RR-DPU-14, Att. A).[29] The purpose, applicability, eligible facilities, cost recovery, and other components of the Company's proposed TIRF mechanism are described below.

B. The Company's TIRF Proposal

1. Purpose and Applicability

The purpose of the proposed TIRF provision of the Company's LDAC tariff is to establish a procedure that allows NEGC to adjust its rates annually for recovery of the revenue

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28 When NEGC filed its rate case in the instant proceeding on September 16, 2010, the Department had not yet approved National Grid's TIRF.

29 The Company provided a schedule that lists all changes, a brief description of the issues relating to those changes, and citations to the applicable initial and revised provisions of the LDAC tariff (RR-DPU-14, at 2-3). This includes, among other things: (1) the elimination of the recovery with carrying charges of the revenue requirement in excess of the proposed one percent cap; (2) a revised calculation of the O&M offset based on a three-year weighted average costs instead of the initially proposed O&M offset based on test year costs; and (3) a property tax rate based on the Company's most recent rate case, D.P.U. 10-114 (RR-DPU-14, at 2; Att. at 14-20).

requirement associated with the replacement of non-cathodically protected steel mains and services, small diameter cast iron and wrought iron mains, and other eligible facilities (Exh. NEGC-JDS-1-15, at 17). The Company stated that the TIRF is the rate component of the LDAF, by which it will recover the aggregate TIRF revenue requirement for targeted infrastructure investments made since December 31, 2009, and through December 31st of the calendar year preceding the Company's annual recovery period beginning November 1st (Exh. NEGC-JDS-1-15, at 18). The TIRF component of the LDAC tariff will be determined annually and applied to all firm sales and firm transportation throughput subject to review and approval by the Department (Exh. NEGC-JDS-1-15, at 17). NEGC proposes to submit a status report to the Department after five years to assess whether the Company's replacement pace continues to be appropriate (Exh. NEGC-JMSw-1, at 11).

2. Eligible Facilities

NEGC proposed that the investments eligible for recovery through the TIRF are those facilities installed in connection with the projects undertaken by the Company to replace non-cathodically protected steel mains and services, small diameter cast iron and wrought iron mains and services, and any connected facilities such as non-cathodically protected steel and small diameter cast iron and wrought iron services, meters, and regulators that must be installed or replaced to enable the main replacement to become operational (Exh. NEGC-JDS-1-15, at 17-18).[30]

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30 More specifically, the investments associated with eligible facilities include the following plants with their associated DPU/FERC plant account numbers: Mains - Transmission (Account 367/367); Mains – Distribution (Account 367/377);

The Company explains that the replacement of non-cathodically protected services provides the same benefits as result from the replacement of non-cathodically protected steel mains (Exh. NEGC-JMSw-1, at 9). Regarding services located inside a customer's premises, the Company stated that it has a limited ability to detect corrosion on these types of services because the inside location of the Company's pipe makes it not readily accessible to corrosion inspection (Exh. NEGC-JMSw-1, at 9). As a result, the Company claims that it is extremely difficult to identify a failure of this pipe segment unless a leak occurs (Exh NEGC-JMSw-1, at 9). The Company states that although in the past it has replaced these services when a leak was detected, the Company's experience indicates that an accelerated, systematic removal of this type of service is highly beneficial (Exh. NEGC-JMSw-1, at 9-10). NEGC states that the accelerated replacement of these types of customer services is vital and should be accomplished through the TIRF (Exh. NEGC-JMSw-1, at 10).

3. Eligible Costs and One Percent Cap on Cost Recovery

The Company proposes that the costs eligible for recovery through the TIRF will include depreciation, property taxes, return, and income taxes associated with the Company's targeted infrastructure capital investment (Exh. NEGC-JDS-1-15, at 17). The capital costs of

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Services – Distribution (Account 380/380); Meters – Distribution (Account 381/381); Meters Installation – Distribution (Account 382/382); and House Regulators – Distribution (Account 383/383) (Exhs. NEGC-JDS-1-15, at 18; NEGC-JDS-1, at 19; RR-DPU-14, Att. A, at 15).

these investments include the cost of removal and applicable overhead and burden costs (Exhs. NEGC-JDS-1-15, at 17; DPU-NEGC-3-41).[31]

The Company states that annually it will first calculate the TIRF revenue requirement associated with its capital spending on eligible facilities for the calendar year just completed (Exh. NEGC-JDS-1, at 20). Then the Company will add this revenue requirement to the cumulative revenue requirement associated with its capital spending on eligible facilities for the prior calendar years already being recovered in the TIRF (Exh. NEGC-JDS-1, at 20).[32]

The Company proposes that the total annual increase in revenue requirement recovered through the TIRF component of the LDAC for the current year will not exceed one percent of the Company's total actual revenues from firm sales and firm transportation throughput during the most recent calendar year, with firm transportation throughput being adjusted by imputing the Company's cost of gas charges for that annual period (Exhs. NEGC-JDS-1-15, at 17; NEGC-JMSw-1, at 10). The Company further proposes that the total annual incremental

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31 The Company defined these overhead and burden costs to include: (1) total labor burden expenses consisting of: (a) payroll tax expense; and (b) employee benefits including sick leave and incentive compensation paid, net of pension and PBOP recovered through the pension adjustment factor; (2) transportation and work equipment expenses; and (3) other overhead expenses consisting of: (a) supervisory payroll net of capitalized amount; and (b) allocated corporate joint and common management expenses, net of capitalized expense (RR-DPU-16, Att. at 1-2). For another example of company-specific definitions of labor overheads and burden costs, see D.P.U. 10-55, at 73 n.53.

32 The Company provided illustrative calculations of the TIRF annual revenue requirements using its annual forecasts of TIRF capital investments for 2010 through 2014 (Exhs. NEGC-JDS-1, at 21; NEGC-JDS-1-8; NEGC-JDS-1-9).

revenue requirement in excess of the one percent cap will be deferred for recovery in a later TIRF filing (Exhs. NEGC-JDS-1-15, at 19; NEGC-JMSw-1, at 10).

More specifically, all or a portion of the deferred revenue requirement, plus carrying costs, will be included in a subsequent TIRF filing provided that the sum of the revenue requirement in that subsequent year plus the deferral amount or portion thereof does not exceed the one percent cap for that year (Exh. NEGC-JDS-1-15, at 19). The Company proposes that the carrying charges on the deferral amount be calculated on the average deferred balance using the Bank of America prime-lending rate (Exh. NEGC-JDS-1-15, at 19). NEGC adds that all unrecovered, accumulated eligible targeted infrastructure investments made since December 31, 2009, would be eligible for inclusion in rate base for recovery through the new base rates to be set in NEGC's next base rate proceeding (Exh. NEGC-JDS-1-15, at 19).

The Company indicated during the proceeding that, at the time when it was developing its TIRF filing, its proposal for the deferral of the amount above the one percent cap and the associated carrying charges reflected what was proposed by National Grid in D.P.U. 10-55 (Tr. 2, at 212). NEGC, however, recognized that the Department's subsequent decision in D.P.U. 10-55 denied National Grid's proposal, and that the amount in excess of the one percent cap will be treated as rate base addition with no recovery of those costs until the company's next general rate case (Tr. 2, at 212).

4. O&M Offset Credited through TIRF

The Company proposes that the annual amount allowed for recovery through the TIRF be reduced by an O&M offset equal to $3,535 for every mile of replaced non-cathodically protected steel and small diameter cast iron and wrought iron mains (Exhs. NEGC-JDS-1, at 21-22; NEGC-JDS-1-7 (rev); AG-11-15, Att. C; DPU-NEGC-3-37, Att. A at 3; NEGC-JMSw-1, at 10; NEGC-JDS-1-15, at 17; Tr. 2, at 214-216). This O&M offset represents reduced leak repair activity and is reflected as a credit to TIRF costs (Exh. NEGC-JDS-1, at 21). The Company indicates that this O&M offset of $3,535 per mile of replaced mains represents the 2009 average cost of leak repairs on non-cathodically protected steel and small diameter cast iron and wrought iron mains in its distribution system, which includes O&M costs for services (Exhs. NEGC-JDS-1-7 (rev); AG-11-15, Att. C; DPU-NEGC-3-37, Att. A at 3; DPU-NEGC-3-30; NEGC-JMSw-1, at 10; Tr. 2, at 214-215).

NEGC also provided the O&M offsets for 2007 and 2008, based on the average costs of leak repairs for those years, equal to $4,478 and $3,992, respectively, per mile of mains including the costs of services replaced (Exh. DPU-NEGC-3-37, Att. A at 1-2; RR-DPU-13, Att. at 1-3). For the three-year period from 2007 through 2009, the Company estimated two averages: (1) a simple average O&M offset equal to $4,002 per mile;[33] and (2) a weighted average O&M offset equal to $3,959 per mile of replaced mains (RR-DPU-13). The Company explains that the weighted average for the three-year period is more appropriate, compared to

[33] This is equal to the average O&M cost of leak repair per mile of unprotected steel and small diameter cast iron and wrought iron mains of $4,478.41 in 2007, $3,991.60 in 2008 and $3,534.64 in 2009 (RR-DPU-13, at 1-4; Exh. DPU-NEGC-3-30).

the simple average, because it more precisely includes changes in leak rates, as well as, leak repair costs over that three-year period (RR-DPU-13).[34]

5. Per Therm Charges and Effective Date of the TIRF

The Company proposed that the per therm charges for the TIRF, included in the Company's LDAF rates, be calculated for three separate customer rate class groups: (1) residential non-heating and residential heating rate classes (R/T-1, R/T-2, R/T-3, and R/T-4); (2) C&I low load factor rate classes (G/T-41, G/T-42, and G/T-43); and (3) C&I high load factor rate classes (G/T-51, G/T-52, and G/T-53) (Exh. NEGC-JDS-1, at 20). NEGC proposed that the cumulative TIRF revenue requirement will be allocated to each of these three rate groups according to a mains and services allocator[35] (Exhs. NEGC-JDS-1, at 20; NEGC-JDS-1-2; DPU-NEGC-3-34; AG-12-18, Att. A, at 1; Tr. 2, at 158-159; RR-DPU-17). To determine the TIRF, the rate class group allocated share of the cumulative TIRF revenue

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34 In calculating the weighted average O&M offset, the Company uses: (1) the three-year average number of miles of unprotected steel and small diameter cast iron and wrought iron mains replaced; (2) the three-year average leaks repaired by mains and services replacements; (3) the three-year O&M expenses for the maintenance of mains (Account 887) and services (Account 892); and (4) the three-year average leak rate per mile of unprotected steel and small diameter cast iron and wrought iron mains (RR-DPU-13, Att. at 1; Exh. DPU-NEGC-3-30).

35 The mains and services allocator is based on the results of the Company's allocated cost of service study where the various rate base components including mains and services are allocated to different rate classes (Exhs. NEGC-JDS-1, at 20; NEGC-JDS-1-2; DPU-NEGC-3-34; AG-12-18, Att. A at 1; RR-DPU-17; Tr. 2, at 158-159). In determining the mains and services allocator for the three rate groups, the Company summed the amounts of mains and services allocated to the rate classes comprising each rate group (Exhs. NEGC-JDS-1, at 20; NEGC-JDS-1-2; DPU-NEGC-3-34; AG-12-18, Att. A at 1).

requirement will be divided by the projected sales and transportation throughput for that rate class group for the November 1st through October 31st recovery period (Exhs. NEGC-JDS-1, at 20-21; NEGC-JDS-1-10; NEGC-JDS-1-15, at 17).

The Company's initial TIRF adjustments will be based on calendar year 2010 data for rates effective November 1, 2011 (Exhs. NEGC-JDS-1, at 20; NEGC-JDS-1-15, at 17; RR-DPU-17). The Company stated that it will prepare an annual TIRF filing on or before May 1st of each year in which it will provide detailed documentation for all plant additions related to bare steel, cast iron, and wrought iron mains, services, and associated facilities replacement that were booked in the prior calendar year (Exhs. NEGC-JDS-1, at 22; NEGC-JDS-1-15, at 17). The Company added that it will file additional support and analysis for the TIRF adjustment, together with the proposed revenue decoupling adjustment factor, as part of the Company's annual LDAF filing by August 1st of that year (Exhs. NEGC-JDS-1, at 22; NEGC-JDS-1-4). The Company indicated that in its next base rate proceeding, all previous years' TIRF spending will be included in the new base rates established in that case (RR-DPU-15).[36]

6. <u>Ratemaking Treatment of Overhead and Burden Costs</u>

The Company proposes to apply two tests to the TIRF calculations: Step 1 ensures that no portion of the O&M overheads and clearing account burden costs that are recovered

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[36] The Company described with supporting graphical illustration how the proposed TIRF mechanism and the annual TIRF rate adjustments would fit with NEGC's next base rate proceeding, to demonstrate that there will be no double counting or overlap associated with the recovery of the TIRF capital expenditures through the TIRF rate adjustments and the new base rates (RR-DPU-15, Att.).

through the TIRF is also recovered in the level of O&M overhead expenses in base rates; and Step 2 ensures that the amount of overheads and burden costs that are assigned to TIRF-related projects is equal to the ratio of the TIRF to non-TIRF direct capital costs in that year (Exh. NEGC-JDS-1, at 23-24). The Company stated that these tests are designed to address the Department's concern regarding the potential for double recovery of O&M overheads and burden costs and shifts in overhead allocations between TIRF and non-TIRF capital projects (Exh. NEGC-JDS-1, at 23-24). The Company filed illustrative schedules with detailed description of how it will implement these two steps (RR-DPU-16, Att. at 1-3).

More specifically, the Company stated that in addition to the project-specific documentation that it will file during its annual TIRF compliance filings, it will file schedules to demonstrate that there is no double counting of the recovery of those O&M overhead and burden costs through the TIRF mechanism and the recovery through base rates (Exh. NEGC-JDS-1, at 23; RR-DPU-16, at 1; see Exh. AG-12-22; RR-DPU-36). In order to perform Step 1, the Company states that it is necessary to establish the level of O&M overhead and burden expense, included in the cost of service established in the instant proceeding, to which will be compared the actual O&M overhead and burden expenses incurred during the year when the TIRF-related investments were made (RR-DPU-16, at 1).

The Company indicated that based on its initial filing, for example, the total O&M overhead and burden baseline amount included in base rates would be $4,397,051

(RR-DPU-36, at 1; Att. at 1, 1.17).[37] This baseline amount represents the O&M overhead and clearing account burden costs that would be recovered through base rates if the Company's filing was approved without change (RR-DPU-36, at 1). To the extent that the actual TIRF O&M overheads and burdens exceed the baseline amount, no adjustment will be made on the annual spending amount requested for recovery through the TIRF (Exh. NEGC-JDS-1, at 23; RR-DPU-16, at 3). If, however, the actual TIRF O&M overheads and burdens for that year are less than this baseline amount, the total TIRF spending for that year will be reduced by the difference between the actual TIRF O&M overheads and burdens for that year and the established baseline amount (Exh. NEGC-JDS-1, at 23-24; RR-DPU-16, at 2-3, Att. at 2).

In Step 2, the Company proposes that the actual total overhead and burden costs that are reallocated to the costs of both TIRF and non-TIRF capital projects, after adjusting for the required change in Step 1, be in proportion to the actual direct TIRF and non-TIRF costs incurred in that year (RR-DPU-16, at 3; Att. at 3).

C. Positions of the Parties

1. Attorney General

The Attorney General opposes NEGC's proposed TIRF and recommends that the Department reject the proposal for a number of reasons (Attorney General Brief at 9-11, 14-16). First, the Attorney General claims that the only provision of the proposed

[37] This total overhead and burden cost of $4,397,051 consists of: (1) total labor loads or burden expenses in the amount of $2,750,630, net of pension and PBOP recovered through the pension adjustment factor in the amount of $2,621,225; (2) transportation and work equipment expenses in the amount of $495,114; and (3) other overhead expenses in the amount of $1,151,307 (RR-DPU-16, at 1-2, Att. at 1).

TIRF that functions as a customer safeguard is the proposed cap on the annual TIRF cost recovery amount of one percent of total revenues (Attorney General Brief at 8). The Attorney General contends that this cap alone is not an adequate safeguard for ratepayers (Attorney General Brief at 9).

The Attorney General states that, although the Company proposes to file annual and five-year TIRF reports with the Department, such proposed TIRF reports contain no performance benchmarks to judge the Company's performance or progress in attaining its stated goal of replacing 50 percent of its "leak-prone" pipes over a 15-year period (Attorney General Brief at 8-9, citing Exhs. NEGC-JMSw-1, at 11; AG-DED-1, at 25). The Attorney General adds that the Company failed to propose any milestones regarding how this 50 percent goal will be met, such as reducing the leaks per mile, and that there is no provision for penalties should the Company fail to perform adequately (Attorney General Brief at 8-10).

Second, the Attorney General claims that the Company did not provide any evidence supporting the need for accelerated mains replacement, such as the age of its facilities, and comparable data on a peer group of gas LDCs, including age of facilities, leaks per mile of mains, leaks per service, and service quality performance (Attorney General Brief at 9-10, citing Exhs. AG-4-27; AG-4-29; AG-6-7; AG-DED-1, at 15; Tr. 1, at 19-20). The Attorney General also claims that NEGC has not demonstrated that its performance is below par when compared to a peer group of LDCs, and that there is no evidence to demonstrate that the

Company's leak rate is worse than its peers to justify the implementation of a special cost recovery mechanism (Attorney General Brief at 9-10).[38]

Third, the Attorney General claims that the Company did not provide any cost-benefit analysis for its replacement program targeting its leak-prone facilities, rejecting the Company's position that it is only prudent to examine the costs and benefits of major capital projects when they are growth-related and that mains replacement activities are not made with a cost-benefit analysis but instead on an as-needed basis (Attorney General Brief at 11, citing Tr. 1, at 20-21). The Attorney General contends that the Department should reject this proposition because it implies that the Department would have to find that any dollar amount spent on capital projects would be prudent and that the cost could be passed on to ratepayers regardless of the rate impact consequences or benefits received by customers (Attorney General Brief at 11). The Attorney General asserts that, at a minimum, even for non-growth mains replacement projects under its targeted replacement of leak-prone facilities, NEGC should be required to demonstrate cost-containment for the project, whether through cost-benefit analysis or some other managerial tools (Attorney General Brief at 11, citing Boston Gas Company, D.P.U. 93-60, at 35-36 n.13 (1993)).

Fourth, the Attorney General argues that the Company has provided no evidence that current rate regulation hinders NEGC from providing safe and reliable service and that the

38 The Attorney General, for example, notes that data from the United States Department of Transportation Pipeline and Hazardous Material Safety Administration shows that utilities with a high proportion of leak-prone mains, such as NEGC, do not always have a high leak rate (Attorney General Brief at 10, citing Exh. AG-DED-1, Sch. DED-9).

TIRF is necessary to provide such service (Attorney General Brief at 12, citing Exh. AG-4-35). The Attorney General contends that NEGC was unable to describe or quantify any of the benefits to public safety, reliability, and the environment, which NEGC claimed will result from its TIRF (Attorney General Brief at 12, citing Tr. 1, at 22-23).

The Attorney General asserts that the evidence does not support the need for the TIRF, noting that the Company's proposed rate of replacement of approximately 7.0 miles of main per year was achieved in 2009 without the benefit of a TIRF mechanism (Attorney General Brief at 12, citing Exh. AG-4-45, Att.). In addition, the Attorney General points out that in 2001, NEGC replaced 6.01 miles of mains and in 2006, 2007, and 2008, NEGC replaced 4.20 miles, 3.64 miles, and 5.16 miles of mains, respectively, under the traditional regulatory framework (Attorney General Brief at 12-13, citing Exh. AG-4-45, Att.).

Fifth, the Attorney General claims that, like other cost trackers, the TIRF is inefficient because it reduces regulatory lag and eliminates a utility's motivation to reduce costs (Attorney General Brief at 13). The Attorney General claims that the longer the regulatory lag, the more incentive a utility has to control its costs because such a lag imposes penalties for inefficiency but rewards efficiency, thereby allowing a company to keep higher profits for a period of time and reap the benefits of superior performance (Attorney General Brief at 13).

The Attorney General argues that where there is a cost pass-through mechanism, with little or no regulatory scrutiny, rational utility management would exert minimal effort in controlling costs because doing so would have no effect on profits (Attorney General Brief at 13). The Attorney General adds that the difficult problem for the regulator is to detect when management is lax because lax management translates into a higher cost of service to customers (Attorney General Brief at 14). The Attorney General concludes that the proposed TIRF removes regulatory lag and will ultimately cause higher rates for the Company's customers because NEGC will no longer have an incentive to minimize costs (Attorney General Brief at 14).

Finally, the Attorney General claims that the Company's proposed TIRF is inconsistent with recent Department decisions (Attorney General Brief at 14, citing D.P.U. 10-55; D.P.U. 09-30). The Attorney General, however, suggests that, if the Department finds that a TIRF is necessary for NEGC, it should make the following changes in NEGC's proposed TIRF (Attorney General Brief at 14-15). First, deny the inclusion of carrying charges applied to any amount in excess of the one percent cap, noting that the Company acknowledged that such carrying charge was not approved in D.P.U. 10-55 and D.P.U. 09-30 (Attorney General Brief at 14, citing Tr. 2, at 154-155). Second, reject the proposed one-year measure of the leak repair O&M offset and instead consider the use of an O&M offset based on three to five years' rolling averages. The Attorney General claims that an O&M offset based on a three-year rolling average is $4,211 compared to the Company-proposed offset of $3,535 (Attorney General Brief at 15, citing Exh. AG-DED-1, at 28). Third, reject the Company's proposal to use a mains and services allocator for allocating the TIRF revenue requirement and adopt the rate base allocator approved in D.P.U. 10-55 (Attorney General Brief at 15, citing Exh. AG-DED-1, at 29). Finally, limit the term of NEGC's proposed TIRF to the Company's next rate proceeding, consistent with the term approved by the Department in D.P.U. 09-30 and D.P.U. 10-55 (Attorney General Brief at 15, citing Exh. AG-DED-1, at 27).

2. DOER

DOER recommends that the Department grant the Company a form of capital tracking mechanism that accelerates the replacement of its leak-prone pipes (DOER Brief at 5). DOER observes that NEGC's distribution system has a high degree of leak-prone pipes and that a replacement program to replace those leak-prone facilities, supported by a TIRF cost recovery mechanism, is justified in order to more quickly improve the reliability and safety of NEGC's gas distribution system (DOER Brief at 5). DOER also recommends including among the eligible TIRF facilities those bare steel services associated with inside meters, because those services have the additional risk of leaks occurring inside a customer's premise (DOER Brief at 5).

DOER states that it supports the O&M offset proposed by the Company, but subject to a determination by the Department whether a three-year average O&M offset could provide a more accurate representation of leak repair savings (DOER Brief at 6). DOER recommends approval of the proposed one percent cap on the TIRF revenue requirement but with modifications (DOER Brief at 6). More specifically, DOER asserts that NEGC's proposal to collect any revenue requirement above the one percent cap in subsequent years should be rejected (DOER Brief at 6). DOER expresses its concern that allowing the Company to collect unrecovered TIRF revenue requirements in subsequent years could incent NEGC to under-spend on TIRF-related projects in future years in order to leave room within the one percent cap to recover past TIRF-related revenue requirements (DOER Brief at 6). DOER states that it expects the Company to make TIRF-related annual investments at the level which is at least equal to the full one percent cap (DOER Brief at 6).

DOER recommends that, like the case with all other capital investments, there should be no carrying charges on the TIRF-related capital not recovered through the TIRF mechanism (DOER Brief at 6). DOER states that to the extent NEGC determines that it must exceed the cap in order to meet necessary reliability and safety requirements, the Company is obligated to incur those costs and is free to make the appropriate filings with the Department to adjust its TIRF program (DOER Brief at 6).

DOER also recommends that the Department require the Company to apply the method approved in D.P.U. 10-55, relating to labor overhead and burden costs, to prevent double recovery of those costs (DOER Brief at 6-7). DOER suggests that, although the Company's proposed two-step process appears similar to the method approved by the Department in D.P.U. 10-55, the Department should direct the Company to use a method identical to that approved for National Grid in D.P.U. 10-55 (DOER Brief at 6-7). DOER explains that using the same method approved in D.P.U. 10-55 would expedite the review of TIRF filings by standardizing the information that is to be included in those filings (DOER Brief at 6-7). DOER maintains that the Department should allow NEGC to collect through the TIRF mechanism only the portion of TIRF-related capital that, when added to NEGC's other capital investments, exceeds the Company's depreciation expense (DOER Brief at 7).

Finally, DOER recommends that the Department reject the Company's proposed mains and services allocator for allocating the TIRF revenue requirement (DOER Brief at 7, citing Exh. NEGC-JDS-1, at 20). DOER explains that in D.P.U. 10-55, the Department noted that because the TIRF investments will cover not only mains but also services and other eligible facilities, it found that a rate base allocator is a more stable and appropriate basis for allocating TIRF-related expenses (DOER Brief at 7, citing D.P.U. 10-55, at 143).

3. Company

Regarding its proposed mains and services allocator for allocating the TIRF revenue requirement to the three customer groups,[39] NEGC claims that such allocator closely relates to the capital investment categories that are included in the Company's TIRF proposal (Company Brief at 89, citing Exh. NEGC-JDS-1, at 20; RR-DPU-14, Att. A at 14). The Company explains that this allocator was derived from the net plant mains and services allocated to each of the Company's rate classes as determined in its allocated cost of service study ("COSS") (Company Brief at 89, citing Exh. NEGC-DAH-9, at 1-8).

In response to the Attorney General's and DOER's proposal to instead use the rate base allocator approved in D.P.U. 10-55, NEGC claims that in D.P.U. 10-55, the company proposed two alternative allocators, one based on mains and another on rate base (Company Brief at 90, citing D.P.U. 10-55, at 143). NEGC explains that the Department, noting that the TIRF investments will cover not only mains but also associated services and other eligible

[39] The three customer groups are: (1) residential heating and non-heating customers; (2) C&I low load factor customers; (3) C&I high load factor customers (Exh. NEGC-JDS-1, at 20).

facilities, found that a rate base allocator, as opposed to the mains allocator, is a more stable and appropriate basis for allocating TIRF-related costs (Company Brief at 90, citing D.P.U. 10-55, at 143). NEGC explains that it proposed the mains and services allocator because it would be a more stable and appropriate basis for allocating TIRF-related costs than a "mains only" allocator (Company Brief at 90). The Company adds that it did not propose a rate base allocator because rate base includes cost categories that have no bearing on investments associated with TIRF-related facilities, such as intangible plant, manufactured gas production plant, customer deposits, materials and supplies inventory, and other cash working capital (Company Brief at 90, citing Exh. NEGC-JMS-2, Sch. B). NEGC concludes that its proposed mains and services allocator is consistent with the Department's decision in D.P.U. 10-55 relating to the allocation of the TIRF revenue requirement (Company Brief at 90).

On the inconsistencies claimed by the Attorney General and DOER of the Company's proposed TIRF with what was approved by the Department in D.P.U. 09-30 or D.P.U. 10-55, NEGC explains that during the proceeding, it made revisions to the proposed TIRF mechanism to address all of the identified inconsistencies (Company Brief at 90). The Company provided a revised LDAC tariff that deleted its initial proposal to recover any portion of the TIRF revenue requirement in excess of the one-percent cap, with carrying charges, in its next TIRF filing (Company Brief at 91, citing RR-DPU-14, Att. A, at 16-17). The Company claims that its revised proposal with respect to the one percent cap is consistent with the approach approved in D.P.U. 09-30 and D.P.U. 10-55 (Company Brief at 91).

Regarding the Attorney General's suggestion to use an O&M offset based on a rolling three-year average of leak repair cost savings, the Company agrees with the Attorney General on this issue (Company Brief at 91, citing Attorney General Brief at 15). The Company explains that its revised LDAC tariff includes a description of the calculation of the O&M offset that is consistent with Department precedent (Company Brief at 91-92, citing RR-DPU-14, Att. A at 13). In addition, NEGC states that it has provided a calculation of the three-year weighted average O&M savings for years 2007 through 2009 equal to $3,958.74 (Company Brief at 92, citing RR-DPU-13).[40]

D. Analysis and Findings

1. Introduction

As of the end of 2009, non-cathodically protected bare steel and small diameter cast-iron facilities, considered to be leak-prone facilities, comprised 43 percent of NEGC's distribution infrastructure, and the replacement of these facilities pose the greatest operational challenge in the Company's distribution system (Exh. NEGC-JMSw-1, at 8-9, 12). To support

[40] NEGC states that the Attorney General has calculated a rolling three-year average O&M offset equal to $4,211 (Company Brief at 92 n.15, citing Attorney General Brief at 14; Exh. AG-DED-1, at 28). The Company states that the three-year average O&M offset provided in the response to Record Request DPU-13 is based on leak and leak repair data that was provided in the response to Exhibit AG-11-15 (Company Brief at 92 n.15). The Company claims that the Attorney General's calculations were based on leak data that were revised in Exhibit DPU-NEGC-3-37 and maintains that the information provided in Exhibit AG-11-15 is the more appropriate and updated data for this calculation (Company Brief at 92 n.15).

its program of replacing leak-prone facilities, the Company has proposed a ratemaking mechanism that is similar to the TIRF mechanism approved in D.P.U. 10-55.[41]

The Department has recognized that there are public safety, service reliability, and environmental issues associated with the continued existence and aging of leak-prone facilities in gas companies' distribution systems. D.P.U. 09-30, at 133. The Department concluded that approval of a TIRF mechanism is likely to provide an incentive for more sustained and aggressive replacement of aging infrastructure, while lessening the impediment of current capital constraints. D.P.U. 10-55, at 122. In addition, the Department stated that such a sustained replacement of leak-prone facilities is appropriate and desirable from a public policy perspective given the potential benefits to public safety, service reliability, and the environment. D.P.U. 10-55, at 121; D.P.U. 09-30, at 133-134. Here, we reaffirm that a sustained replacement of leak-prone facilities for NEGC is appropriate and desirable from a public policy perspective given the potential benefits to public safety, service reliability, and the environment.

The Department, however, emphasized that the approved TIRF mechanism is designed not to supplant traditional ratemaking. D.P.U. 10-55, at 122. Rather, the Department stated that the TIRF is a special ratemaking mechanism, with a limited scale and scope, designed to

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41 The Department approved a TIRF mechanism for Bay State Gas Company that allows the recovery of capital costs for replacement of non-cathodically protected bare steel. D.P.U. 09-30, at 120-121, 134. The Department approved a TIRF mechanism for National Grid that allows the recovery of capital costs for replacement of non-cathodically protected bare steel, small-diameter cast iron, and wrought iron facilities. D.P.U. 10-55, at 122.

support the replacement of bare steel, cast iron, and wrought iron mains and other associated facilities that the company deemed required special attention as it performed its public service obligation to maintain a safe and reliable distribution system. D.P.U. 10-55, at 122. Here, we reaffirm the same special ratemaking policy.

The Attorney General raised a number of arguments against Department approval of the Company's proposed TIRF. We categorized them into four sets of issues. The first set relates to her claim that: (1) the Company has not demonstrated the need for an accelerated replacement of leak-prone facilities; (2) the proposed seven-miles per-year pace of replacement was achieved during the test year under the traditional regulatory framework without the benefit of a TIRF mechanism; and (3) the Company has provided no evidence to demonstrate that current rate regulation hinders NEGC from providing safe and reliable service and that the TIRF mechanism is necessary to provide such service.

The second set of issues relates to the Attorney General's claim that: (1) the one percent cap on the TIRF annual revenue requirement is not an adequate safeguard for ratepayers; (2) the proposed TIRF mechanism does not contain performance benchmarks and milestones, such as reducing the leaks per mile, as a basis for evaluating the Company's performance and progress in attaining its stated goal of replacing 50 percent of its leak-prone facilities over a 15-year period; and (3) the proposed TIRF mechanism does not contain any provision for penalties should the Company fail to perform adequately.

The third set of issues relates to the Attorney General's claim that: (1) the Company did not provide any cost-benefit analysis for its mains replacement program, and mains replacement should not be performed on an as-needed basis without a cost-benefit analysis; and (2) her recommendation that, at a minimum, even for non-growth mains replacement projects under its TIRF mechanism, NEGC should be required to demonstrate cost-containment for the project, whether through a cost-benefit analysis or some other managerial tools.

Finally, the Attorney General claims that the TIRF, like other cost trackers, is inefficient because it reduces regulatory lag, eliminates a utility's motivation to reduce costs, and will ultimately result in higher rates for the Company's customers. We address each of these four sets of issues below.

2. Need for Leak-Prone Facilities Replacement

Regarding the first set of issues, we have reviewed the record in this proceeding and find that there is evidence demonstrating the need for NEGC's replacement of its leak-prone facilities at the test year level, which was an accelerated level compared to the replacements made from 2004 through 2008, noting that a significant portion of the Company's mains and associated services are leak-prone. More specifically, the record shows that at the end of the test year, 50.33 miles and 120.21 miles of the Company's mains were non-cathodically protected bare steel and small-diameter cast iron and wrought iron mains, respectively (Exh. DPU-NEGC-3-23, Att.).[42] These leak-prone mains represent eight and 19 percent,

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42 As of 2009, the vintage of NEGC's total miles of mains (604.49) was: (1) unknown = 72.265 miles (12 percent); (2) Pre-1940 = 95.556 miles (16 percent); (3) 1940-1949 = 15.283 miles (3 percent); (4) 1950-1959 = 45.821 miles (8 percent); (5) 1960-1969 = 139.494 (23 percent); (6) 1970-1979 = 66.751 miles (11 percent); (7) 1980-1989 = 57.138 miles (9 percent); (8) 1990-1999 = 66.942 miles (11 percent); (9) 2000-2009 = 45.240 miles (7 percent) (see NEGC 2009 Gas Distribution System, Annual Report, Form PHMSA F7100.1-1 (to U.S. Department of Transportation, Pipeline and

respectively, of the Company's total number of miles of mains (Exh. DPU-NEGC-3-23, Att.).[43]

The record also shows that the Company's total number of leaks discovered increased from 345 in 2006 to 709 in 2009, for an average increase over this period of 35 percent per year (Exh. AG-4-26, Att.).[44] Over the same period the number of Grade 1 leaks, leaks that represent an existing or probable hazard to persons or property and require immediate repair upon discovery, increased from 58 in 2006 to 146 in 2009 for an average increase over this period of 51 percent per year (Exh. AG-4-26, Att.). As noted in Section V.K.1., below, the increase in the number of leaks repaired from 428 in 2008 to 731 in 2009 is a result of the increase in the total number of leaks discovered in 2009. The number of leaks repaired in

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Hazardous Materials Safety Administration)). 220 CMR § 113.04(1) provides that cast iron pipes shall not be installed for the distribution of gas after April 12, 1991. Federal regulations (49 C.F.R. § 192.455) required that buried pipelines installed after July 31, 1971, must be cathodically protected from external corrosion.

43 These percentages are comparable to those of National Grid and Bay State Gas Company, for which the Department approved similar TIRF mechanisms. More specifically, the percentages for National Grid (combined Boston Gas Company, Essex Gas Company, and Colonial Gas Company service areas) at the end of 2008 are eleven percent non-catholdically protected bare steel and 19 percent cast iron and wrought iron mains. D.P.U. 10-55, at 66 n.44. Those for Bay State Gas Company as of the end of 2008 are six percent and 15 percent, respectively (see Bay State Gas Company 2008 Gas Distribution System, Annual Report, Form PHMSA F7100.1-1 (to U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration)).

44 2005 is the earliest year when Company data are available showing the breakdown of leaks discovered and repaired by grade of leaks (Exh. AG-4-26, Att.). The number of leaks discovered in 2005 was 417, 113 of which were Grade 1 leaks. These are higher than the 345 total leaks and 58 Grade 1 leaks discovered in 2006 (Exh. AG-4-26, Att.).

2009 was driven significantly by the 45 percent increase in Grade 1 leaks discovered and repaired, from 101 in 2008 to 146 in 2009.

The record further shows that the Company replaced or retired a total of 2.54 miles of mains in 2005, 4.20 miles in 2006, 3.64 miles in 2007, 5.16 miles in 2008 and 7.33 miles in 2009 (Exh. AG-4-45, Att.). The combined number of miles of unprotected bare steel and cast iron and wrought iron mains replaced or retired for the same period are 2.48 miles, 3.66 miles, 3.12 miles, 4.54 miles, 7.22 miles, respectively, representing 98 percent, 87 percent, 86 percent, 88 percent and 98 percent of the annual total number of miles of mains replaced (Exh. AG-4-45, Att.).

The number of miles of cast iron mains replaced or retired progressively increased from 2006 through 2009, i.e.: 0.65 mile in 2006; 1.80 miles in 2007; 2.70 miles in 2008; and 4.59 miles 2009 (Exh. AG-4-45, Att.).[45] Over the same period, the number of Grade 1 leaks discovered similarly progressively increased: 58 leaks in 2006; 94 leaks in 2007; 101 leaks in 2008; and 146 leaks in 2009 (Exh. AG-4-26, Att.).[46]

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45 The corresponding number of unprotected bare steel mains replaced or retired were: 3.01 miles in 2006, 1.32 miles in 2007, 1.84 miles in 2008, and 2.63 miles in 2009 (Exh. AG-4-45, Att.).

46 Over the 21-year period from 1989 through 2009 when comparative data are available, the Company replaced or retired more than five miles of mains per year only in four years: (1) 5.23 miles in 1989; (2) 6.01 miles in 2001; (3) 5.16 miles in 2008; and (4) 7.33 miles in 2009 (Exh.AG-4-45, Att.). For these four years, the number of miles accounted for by cast iron mains replacement or retirement and the corresponding percentages relative to total mains replaced or retired were: (1) 0.03 mile (one percent) in 1989; (2) 2.51 miles (42 percent) in 2001; (3) 2.70 miles in 2008 (52 percent); and (4) 4.59 miles (63 percent) in 2009 (Exh.AG-4-45, Att.). While the percentage of cast iron replaced or retired progressively increased over time, those for non-cathodically

Based on the foregoing discussion, we find that there is sufficient evidence to demonstrate the need for NEGC's replacement of its leak-prone facilities at the test year level, which was an accelerated level compared to the replacements made from 2004 through 2008. In addition, we note that the aggregate leak rate of NEGC as of December 31, 2009 is 0.68 leaks per mile (Exhs. AG-12-25, Att.; DPU-NEGC-3-23, Att.). This is comparable to the aggregate leak rate of 0.64 leaks per mile as of the end of 2008 for National Grid's combined service areas of Boston Gas Company, Essex Gas Company, and Colonial Gas Company, for which the Department approved a TIRF mechanism that similarly includes as eligible facilities non-cathodically protected bare steel and cast iron and wrought iron mains, services and associated facilities. D.P.U. 10-55, at 67 n.45, 145 (2010).[47]

We find reasonable the Company's proposal to include cast iron and wrought iron mains and those services and other facilities connected thereto among the eligible facilities under its proposed TIRF mechanism. Therefore, we approve the Company's proposed list of eligible facilities as contained in Record Request DPU-14, Attachment A at Section 1.10(F)(2) at 15.

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protected bare steel declined. More specifically, non-cathodically protected bare steel replacement or retirement accounted for: (1) 5.20 miles (99 percent) in 1989; (2) 3.45 miles (57 percent) in 2001; (3) 1.84 miles (36 percent) in 2008; and (4) 2.63 miles (36 percent) in 2009 (Exh.AG-4-45, Att.).

47 In that case, the Department noted that the 2008 average aggregate leak rate for a peer group of 22 regional gas local distribution companies was 0.29 leaks per mile. D.P.U. 10-55, at 67 n.45.

Although we agree with the Attorney General that current rate regulation does not necessarily hinder NEGC from providing safe and reliable distribution service, and that there is no record evidence to demonstrate that NEGC does not maintain safe and reliable service under such a regulatory framework, we reaffirm our previous conclusion that approval of a TIRF mechanism is likely to provide an incentive for more sustained and aggressive replacement of aging infrastructure, because it lessens the impediment of current capital constraints on a gas distribution company. D.P.U. 10-55, at 122; D.P.U. 09-30, at 133-134.

In the implementation of its leak-prone mains replacement under its TIRF mechanism, the Department directs the Company to maintain continuing and verifiable records of leaks discovered and repaired by material types and by sources of leaks (e.g., mains, services). In the specific case of cast iron mains and services and other facilities connected thereto, we direct the Company to maintain continuing and verifiable record on whether the replacements were undertaken as a result of normal gas operations and maintenance activities or as a result of encroachments (i.e., replacement at trench crossovers or replacement adjacent to a parallel excavation). See 220 CMR §§ 113.04 through 113.07; Investigation by the Department into Proposed Rules Concerning Cast-Iron Pipe used in the Distribution of Gas, D.P.U. 89-254, at 1, 9-11 (1991).

3. Performance Measures, Safeguards and Cost-Benefit Analysis

Here we address the second and third sets of issues raised by the Attorney General. The Department's standard of review for non-revenue producing plant additions is the same as the standard for revenue producing plant additions, that is, both categories of expenditures must be prudently incurred and the resulting plant must be used and useful to ratepayers. D.P.U. 03-40, at 67; D.P.U. 85-270, at 20.

The Department, however, has recognized a distinction between: (1) discretionary non-revenue production plant;[48] and (2) non-discretionary non-revenue producing plant. D.P.U. 03-40, at 67. Plant additions like the replacement of cast iron and wrought iron mains or non-cathodically protected bare steel, which comprise the eligible facilities in the Company's TIRF mechanism, as modified, may be fairly characterized as non-discretionary, non-revenue producing plant because the Company is obligated to replace such mains in order to maintain the integrity of the distribution system. See D.P.U. 03-40, at 67; D.P.U. 08-35, at 19. For such non-discretionary non-revenue producing plant additions, the Department has stated that traditional cost benefit analyses may be inapplicable, but added that a company is expected to demonstrate that it has sought to contain the overall costs of projects.[49] D.P.U. 93-60, at 36 n.13. The Department also emphasized that:

48 Discretionary, non-revenue producing plant refer to projects such as the replacement of a customer information system or construction of a water treatment plant, where a company has a measure of discretion and selects from among a number of options the most cost effective means of meeting the company's operational needs. See D.P.U. 03-40, at 67; Massachusetts American Water Company, D.P.U. 95-118, at 43 45 (1996).

49 The Department has found that a gas utility need not serve new customers in circumstances where the addition of new customers would raise the cost of gas service for existing firm customers. D.P.U. 88-67 (Phase I) at 282-284; D.P.U. 03-40, at 48. The Department has stated that existing customers receive benefits whenever, all other things being equal, the return on incremental rate base added to serve new customers exceeds the company's allowed overall rate of return. D.P.U. 89-180, at 16-17.

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

The Berkshire Gas Company, D.P.U. 92-210, at 24 (1993).

We direct the Company to provide in its annual TIRF compliance filings complete, reviewable, and cohesive documentation or face the risk of exclusion of the cost of a project for recovery in the TIRF annual revenue requirement. In addition, should the Company fail to provide such documentation or if the Department finds a project cost to have been incurred in an imprudent manner, or if the Department finds that the plant is not used and useful based on the evidence presented at the time of the review, the Company may not include or propose to include such plant addition in rate base in its next general rate case.

During such review of the annual TIRF filings, the Department will examine, among other things: (1) the Company's performance relative to its proposed pace of leak-prone pipe replacement and project cost control; and (2) recordkeeping of project work orders and capital authorizations that detail how the project cost estimates were determined, the project closing report, and variance analysis that explains any project cost over-run and details the steps taken by management to control the overall project costs.

We emphasize that any material deficiencies in the Company's TIRF program found during the annual review that contravene the objectives and purposes of this special ratemaking TIRF mechanism will serve as a cause for consideration of termination of TIRF recovery. Therefore, the term of NEGC's TIRF, as modified herein, shall extend until the Company's next general rate case, unless earlier terminated by the Department. That is, continued operation of the Company's TIRF rate recovery mechanism until the Company's next general rate case is conditional on the Company's demonstration in its annual filings that its performance satisfies the underlying goals of providing benefit to public safety, service reliability, and the environment.

4. TIRF Mechanism and Regulatory Lag

The Attorney General has argued that the TIRF mechanism, as a form of cost tracker, is inefficient because it reduces regulatory lag[50] and eliminates a utility's motivation to reduce costs, ultimately resulting in higher rates for the Company's customers. As stated above, the TIRF mechanism, as modified and approved here, is a special ratemaking mechanism with the purpose and intent of providing the Company a reasonable level of financial incentive to address a specific component of its distribution infrastructure that is deemed to be in need of particular attention. Such a special ratemaking treatment is not intended to provide full financial support for capital investment projects nor supplant or eliminate regulatory lag, which provides an incentive to spend efficiently and is inherent in traditional ratemaking principles. D.P.U. 10-55, at 132-133.

As we find in III.D.5., below, a cap of one percent ("one percent cap"), which limits the annual change in revenue requirement associated with the TIRF-related investments during the immediately preceding calendar year to one percent of total revenues for the prior calendar

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[50] Regulatory lag refers to the time gap between when a utility undergoes a change in cost or sales levels and when the utility can reflect these changes in new rates. See D.P.U. 10-55, at 79 n.60.

year, provides sufficient protections for ratepayers by limiting the associated annual rate increase, which addresses rate continuity concerns. See D.P.U. 10-55, at 133; D.P.U. 09-30, at 134. Further, we find that a one percent cap will provide an appropriate incentive for NEGC at least to sustain, and potentially to increase, its current seven-mile per-year pace of replacement of leak-prone mains in its distribution system. See D.P.U. 10-55, at 133; D.P.U. 09-30, at 134.

The Department directs that any TIRF revenue requirement in excess of the one percent cap shall not be deferred or recovered in any subsequent annual TIRF revenue requirement filings and, instead, NEGC shall be able to propose recovery of those expenditures under the traditional ratemaking process in the Company's next general rate case. The record shows that NEGC's proposed seven-miles per-year pace of mains replacement is approximately equal to its 2009 test year level of 7.22 miles of non-cathodically protected bare steel and cast iron and wrought iron mains replaced (Exh. AG-4-45, Att.).

Although this one percent cap on the annual TIRF revenue requirement limits the rate impact on customers, it does not impose on NEGC any limit on the level of capital investment that it can undertake in a given year. NEGC has full discretion to exercise its judgment to maintain the safety and reliability of its distribution system.

To the extent that additional investments in these areas are required that could not be supported under the TIRF mechanism as a result of a one percent cap, or, for that matter, any cap, NEGC will be able to propose recovery of those expenditures under the traditional ratemaking process. Such expenditures beyond the one percent cap would be subject to the regulatory lag inherent in such a traditional ratemaking paradigm.

Based on the above considerations, we find that, on balance, NEGC's proposed TIRF, as modified herein, is consistent with Department precedent.[51] More specifically, we have reviewed the Company's proposals for its TIRF mechanism relating to: (1) eligible facilities;[52] (2) method of calculating the TIRF incremental revenue requirement;[53] (3) one-percent cap on TIRF current annual revenue requirement, as modified herein; (4) O&M offset to costs to be recovered through the TIRF to account for reduced leak repairs; (5) ratemaking treatment of O&M overheads and burdens; and (6) TIRF revenue requirement allocation and recovery, and find them to be consistent with Department precedent. D.P.U. 10-55, at 145; D.P.U. 09-30, at 129-135.

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51 Among other things, Record Request DPU-14, Attachment A, contains revisions to the Company's LDAC tariff relating to TIRF.

52 Section 1.10(F)(2) of the LDAC tariff relating to "Eligible Facilities" lists a DPU/FERC plant account as "Account No. 380/381 Meters - Distribution" (RR-DPU-14, Att. A at 15). The Department directs the Company to revise the account designation to read instead as: "Account No. 381/381 Meters – Distribution."

53 Section 1.10(F)(12) of the Company's revised LDAC tariff relating to the TIRF provides, among other things, that: "TIRF is the separate rate determined for each TIRF Customer Group pursuant to this mechanism that recovers the aggregate TIRF Revenue Requirement for investments made since December 31, 2009 through December 31 of the Calendar Year preceding the annual recovery period beginning November 1" (RR-DPU-14, Att. A at 16; see Exh. NEGC-JDS-1-15, at 18). For clarity, the Department directs the Company to replace the phrase "since December 31, 2009" with "beginning January 1, 2010."

Although the Company initially proposed to defer for future recovery through the TIRF that portion of the TIRF revenue requirement that is in excess of the capped amount, the Company acknowledged during the proceeding that such a proposal was rejected by the Department in its Order in D.P.U. 10-55 (Tr. 2, at 218-220). Accordingly, NEGC submitted a revised LDAC tariff consistent with D.P.U. 10-55 (RR-DPU-14, Att. A). The Department finds that the Company's revision of the LDAC tariff that removes the provision relating to the deferral with carrying charges of that portion of the TIRF revenue requirement in excess of the one percent cap is consistent with Department precedent and accordingly we approve it.

We address below in more details the following issues: (1) cap on annual TIRF revenue requirement; (2) O&M offset to the costs to be recovered through the TIRF to account for reduced leak repairs; (3) ratemaking treatment of O&M overheads and burdens; (4) TIRF revenue requirement allocation and recovery; and (5) term of the TIRF mechanism.

5. Cap on TIRF Annual Revenue Requirement

The Company has proposed that the total annual increase in revenue requirement associated with the immediately preceding year's TIRF-related investment, recovered through the TIRF for the current year, will not exceed one percent of the Company's total actual revenues from firm sales and firm transportation throughput during the most recent calendar year, with firm transportation throughput being adjusted by imputing the Company's cost of gas charges for that annual period (Exhs. NEGC-JDS-1-15, at 17; NEGC-JMSw-1, at 10). Although the Department has previously approved on two occasions a one percent cap on the TIRF revenue requirement, such approvals were based on the records of those proceedings, taking into account a number of factors specific to those cases. D.P.U. 10-55, at 133; D.P.U. 09-30, at 120-121, 134.

In the case of National Grid, for example, the Department noted that if a TIRF mechanism had been in place during the company's 2009 test year, the annual TIRF revenue requirement recoverable in the following year for the actual TIRF-related investments made in 2009 would have represented 0.68 percent of the actual firm billed revenues for the Boston Gas-Essex Gas service area in 2009. D.P.U. 10-55, at 131. Accordingly, the Department rejected National Grid's proposed three-percent cap and found that a one-percent cap provided an appropriate incentive for National Grid to expedite the replacement of its leak-prone mains and associated services and gave sufficient protections for ratepayers. D.P.U. 10-55, at 133.

Here the record shows that the Company's TIRF-related capital expenditures in 2009 for bare steel mains and cast iron and wrought iron mains replacements, assuming a TIRF mechanism had been in place for 2009, were $2,734,738 and $1,019,683, respectively, for a total of $3,754,421 (Exhs. NEGC-JDS-1-6; AG-6-4, Att. A). The resulting TIRF revenue requirement for those TIRF-related capital expenditures would have been $330,931 (Exh. AG-6-4, Att. A). This amount represents 0.43 percent of the Company's 2009 total booked revenue of $77,408,935 (Exh. NEGC-JMS-2, Sch. A-1 (Rev.)).

In addition, the record shows that based on the Company's five-year annual forecasts of TIRF-related capital investments from 2010 through 2014, the annual TIRF revenue requirement, as a percent of total annual Company revenues that includes the requested increase in this case, would have been 0.4 percent in 2010, 0.7 percent in 2011, 0.5 percent in

2012, 0.5 percent in 2013, and 0.5 percent in 2014, for a five-year average of 0.52 percent (Exh. NEGC-JDS-1-9, at 2).

Based on the record in this case and consistent with Department precedent, we find that a one percent cap for NEGC's TIRF mechanism, as modified, provides sufficient protections for ratepayers as it limits the annual rate increase, which addresses rate continuity concerns. See D.P.U. 10-55, at 133; D.P.U. 09-30, at 134. In addition, the Department finds that a one percent cap will provide an appropriate incentive for NEGC to sustain and potentially accelerate its current seven-mile per-year pace of leak-prone mains replacement in its distribution systems. See D.P.U. 10-55, at 133; D.P.U. 09-30, at 134. Accordingly, we accept the Company's proposed one percent cap as indicated in Section 1.10(H) of the modified LDAC tariff as shown in Record Request 14, Attachment A.

6. O&M Offset

In D.P.U. 09-30, the Department approved an O&M offset in the company's TIRF mechanism based on the average leak repair cost-per-mile for bare steel during the period 2004 to 2008. D.P.U. 09-30, at 120, 134; see also Bay State Gas Company's LDAC tariff, M.D.P.U. No. 73, at 16.

In D.P.U. 10-55, although the Department accepted an O&M offset based on test year average leak repair costs[54] and leak rate data, the Department directed the company in its first

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[54] The Department noted that the O&M offset is based on the weighted average cost of leak repairs on non-cathodically protected steel and small diameter cast iron and wrought iron mains replaced during the annual TIRF investment period. D.P.U. 10-55, at 138.

TIRF compliance filing to submit O&M leak repair costs and leak rate data for the three-year period 2008-2010 for Department review. D.P.U. 10-55, at 138-141. The Department stated that since O&M offsets are determined by two component factors, average cost of leak repair and leaks per mile of leak-prone pipes, a three-year rolling average could provide stability in the O&M offset, as influenced by those two component factors. D.P.U. 10-55, at 139-140.

The record shows that NEGC has revised its proposed LDAC tariff indicating that the calculation of the avoided maintenance expense per mile, referred to as Eligible TIRF Savings, shall be based on the weighted average data for the most recent three years as determined according to formulas established by the Department in this case (i.e., the Company's most recent rate case, D.P.U. 10-114) (RR-DPU-14, Att. A at 14). Such revised LDAC tariff, however, does not indicate a specified amount of O&M offset per mile.

In its response to Record Request DPU-13, the Company provided two alternative calculations of the O&M offset using data for the three-year period 2007 through 2009. The first is equal to $4,002 per mile based on the simple average O&M savings for 2007-2009 (RR-DPU-13, Att. at 1, line 34). The second is equal to $3,959 based on the weighted average O&M savings for 2007-2009 (RR-DPU-13, Att. at 1, line 34). The Company reasoned that the O&M offset based on a weighted average is the more appropriate measure because it better reflects changes in leak rates and leak repair costs over the three-year period (RR-DPU-13).

As the Company noted, this offset would be affected by the number of leaks repaired per mile as well as the cost of repair per leak in a given year and, therefore, a weighted average calculation would be a more appropriate measure (RR-DPU-13, Att. at 1; Tr. 2, at 217). The Department finds that such a weighted average calculation is consistent with the O&M offset approved in D.P.U. 09-30, at 120, 134. In addition, this approach provides stability in the O&M offset, consistent with the Department's rate structure goals of rate continuity and earnings stability. D.P.U. 10-55, at 140, 535; D.P.U. 09-30, at 373-374; D.T.E. 03-40, at 365-366; D.T.E. 02-24/25, at 252-253; The Berkshire Gas Company, D.T.E. 01-56, at 134-135 (2001). Accordingly, we approve an O&M offset of $3,959 based on the weighted average O&M savings for the three-year period 2007-2009. In its compliance filing to this Order, the Department directs the Company to revise its proposed LDAC tariff indicating, among others, the specific amount of O&M savings per mile.[55]

7. Ratemaking Treatment of O&M Overheads and Burdens

In D.P.U. 10-55, at 141-142, the Department addressed the issue of potential double recovery of overhead and burden costs, first from the base distribution rates and second from the annual TIRF filings. The Department accepted the company's three-step process as a starting point and for further evaluation its first annual TIRF filing, noting that such a three-step process was proposed during the last days of evidentiary hearings and that the

[55] The Company indicated on brief that the correct data to be used should be that shown in Exhibit AG-11-15, instead of Exhibit DPU-NEGC-3-37 (Company Brief at 92 n.15). The record, however, shows that the Company's calculations of the avoided O&M costs in Record Request DPU-13, Attachment at 1-4, are based on the data provided in Exhibit DPU-NEGC-3-37, Attachment (a) at 1-3. In addition, the response date in Exhibit DPU-NEGC-3-37 is December 2, 2010, which is more recent than the November 19, 2010 response date in Exhibit AG-11-15. Therefore, the Company should use the data in Exhibit DPU-NEGC-3-37, Attachment (a) consistent with the calculations shown in Record Request DPU-13.

parties were not given a reasonable opportunity to review and evaluate that proposal. D.P.U. 10-55, at 142.[56] The Department further directed the company to include in its compliance filing to that Order a schedule showing the level of labor overheads and clearing account burdens recovered through base rates and the pension/PBOP reconciliation adjustment factor mechanism. D.P.U. 10-55, at 142.

Here, NEGC proposed a similar two-step process to prevent such double recovery (see Section III.A.6., above; see also Exh. NEGC-JDS-1, at 23-24; RR-DPU-16, Att. at 1-3). DOER recommends that the Department direct the Company to establish an approach identical to that accepted for National Grid (DOER Brief at 6, citing D.P.U. 10-55, at 141-143). The three-step process in D.P.U. 10-55 is subject to further review and consideration. In addition, there are many aspects of a utility company's financial and accounting operations that could make standardization difficult to implement in the absence of a full record. Thus, we do not adopt DOER's recommendation.

The Company's proposed two-step process appears reasonable and effective in preventing double recovery. We will accept such an approach here subject to further review in

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56 This three-step process consists of: (1) ensuring that National Grid will not double recover costs associated with overhead and burden costs; (2) allocating equally to all capital projects in a given year, including TIRF projects, the overall level of the actual capitalized labor overheads and clearing account burdens, as adjusted in the first step, to avoid the potential for uneven allocation arising from timing differences associated with National Grid's accounting processes; and (3) a recovery cap based on the level of depreciation expense determined in D.P.U. 10-55 applied to the eligible TIRF investments calculated in the first two steps. D.P.U. 10-55, at 141-143 & Stamp-Approved Compliance Filing (November 18, 2010).

the Company's first TIRF compliance filing.[57] In addition, consistent with our directive in D.P.U. 10-55, at 142 and the Company's response to Record Request DPU-16, we direct the Company to include in its compliance filing to this Order schedules showing, among other things, the level of labor overheads and clearing account burdens recovered through base rates and any reconciling mechanisms with complete supporting data and calculations.

8. TIRF Revenue Requirement Allocation and Recovery

In D.P.U. 10-55, at 143, National Grid provided two alternative methods for allocating the TIRF revenue requirements among customer class groups, first, using a mains only allocator, and second, using a rate base allocator. Considering that the TIRF investments will not only cover mains but also associated services and other eligible facilities, the Department found in that case that the rate base allocator is more appropriate. D.P.U. 10-55, at 143.

The record shows that NEGC's proposed TIRF revenue requirement allocator is based on the net plant for mains and services (Exhs. NEGC-JDS-1, at 20; NEGC-JDS-1-2; DPU-NEGC-3-34; AG-12-18, Att. A at 1; Tr. 2, at 158-159). The total net plant for mains and services is $42,414,859 or approximately 84 percent of the total rate base (RR-DPU-17, Att. at 1-4). The remaining 16 percent of total rate base is accounted for by intangible assets, propane, liquefied natural gas, and other distribution plants, which are not related to TIRF investments (RR-DPU-17, Att. at 1-4). If the Company were to use the mains only allocator, it would represent only $17,284,137 or approximately 34 percent of total rate base

57 We conditionally accept the Company's proposed two-step process subject to review of the evidence to be provided by NEGC in its first TIRF annual compliance filing.

(Exh. AG-12-18, Att. A at 1-4). Thus, in this circumstance, using the total rate base allocator would have been more appropriate than using the mains only allocator.

We note that NEGC, however, has proposed a more precise allocator, compared to the mains only allocator or the rate base allocator, that uses mains and services that are included in the Company's eligible TIRF facilities. This allocator uses the results of the Company's allocated cost of service study based on the underlying principle that cost incurrence should follow cost causation (Exhs. NEGC-DAH-1, at 13; NEGC-DAH-9; AG-12-18; RR-DPU-17; see e.g., D.P.U. 10-55, at 534).

We find NEGC's proposed mains and services allocator to be stable and more accurately reflects the associated cost incurrence consistent with Department's rate structure goal of fairness. D.P.U. 10-55, at 535; D.P.U. 09-30, at 373; D.P.U. 08-35, at 221; D.T.E. 01-56, at 134; Boston Gas Company, D.P.U. 96-50 (Phase I) at 133 (1996). Accordingly, we approve the Company's proposed mains and services allocator for the purpose of allocating the TIRF revenue requirements among customer class groups. In its compliance filing to this Order, the Department directs the Company to provide the mains and services allocation factors based on the results of its compliance allocated COSS with supporting schedules, including but not limited to schedules similar to those shown in Exhibit NEGC-JDS-1-2, Exhibit AG-12-18, and Record Request DPU-17.

9. Term of the TIRF Mechanism

In D.P.U. 10-55, at 129, the Department directed that the term of National Grid's TIRF mechanism would be effective until its next general rate case. Here, NEGC's proposed

TIRF mechanism is designed to support its plan to replace approximately seven miles of mains per year, anticipating that over a 15-year period the Company would be able to replace approximately 50 percent of its inventory of bare steel and small-diameter cast iron and wrought iron facilities. Although the provisions relating to the TIRF in the Company's proposed LDAC tariff do not indicate the term of such a TIRF mechanism, the Company indicated during the proceeding that it anticipates that the Department would at least grant a term extending until NEGC's next general rate case (Tr. 2, at 153-154).

Like our determination in D.P.U. 10-55, at 128-129, we will not determine here or endorse a specific term, scope, pace, or approach for NEGC in maintaining and operating its distribution system. The Company is obligated to provide safe and reliable gas distribution service.[58] The Department will not substitute its judgment for utility management's job as to how best to meet and fulfill its service obligations to maintain and operate its system consistent

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58 See Report to the Legislature Re: Maintenance and Repair Standards for Distribution Systems of Investor-Owned Gas and Electric Distribution Companies, D.P.U. 08-78, at 4 (2009) (the Department's comprehensive oversight powers are to ensure reliable and safe services by gas and electric distribution companies to the public); D.P.U. 07-50, at 5 (a goal of the Department is to ensure that the public utility companies it regulates provide safe, reliable, and least-cost service to Massachusetts consumers); Incentive Regulation, D.P.U. 94-158, at 3 (1995) (since its establishment, the goal of the Department has been to ensure that the public utility companies it regulates provide safe, reliable, and least-cost service to Massachusetts consumers); Electric Industry Restructuring, D.P.U. 95-30, at 6 (1995) (same); Integrated Resource Planning, D.P.U. 94-162, at 51-52 (1995) (the Department emphasizes that electric companies are still required to provide safe, reliable, least-cost electric service to their ratepayers, even though companies will no longer be required to submit initial resource portfolios); Mergers and Acquisitions, D.P.U. 93-167-A at 4 (1994) (Department to ensure that utilities subject to its jurisdiction provide safe and reliable service at the lowest possible cost to society).

with safety, reliability and other considerations. D.T.E. 05-27, at 36-37, 39. Accordingly, the TIRF mechanism as modified and approved here will be effective until NEGC's next general rate case unless otherwise ordered by the Department.

10. Conclusion

In conclusion, we find that NEGC's proposed TIRF, as modified herein, strikes an appropriate balance between providing the Company with reasonable ratemaking support for sustaining, if not accelerating, its current pace of replacement of leak-prone mains and associated facilities in its distribution system, and the need to insulate and protect ratepayers from undue rate increases. In addition, we find that such a TIRF, as modified, is consistent with Department precedent and that its operation will result in just and reasonable rates. Accordingly, we approve the provisions of the Company's proposed LDAC tariff relating to the TIRF as shown in Record Request DPU-14, Attachment A, subject to the modifications required herein. In its compliance filing to this Order, the Department directs NEGC to revise its proposed LDAC tariff consistent with the directives in this Order.

IV. RATE BASE

A. Introduction

NEGC reports $111,188,818 in total gross plant in service as of the end of the test year (Exh. NEGC-JMS-2, Schs. B (Rev.), C (Rev.)). The Company made the following reductions to determine its proposed rate base: (1) $48,262,416 in accumulated depreciation;

(2) $3,051,759 in contributions in aid of construction ("CIAC");[59] (3) $180,821 representing an adjustment for NEG Appliance; (6) $401,983 in customer deposits; and (6) $11,898,756 in accumulated deferred income taxes (Exh. NEGC-JMS-2, Sch. B (Rev.)).[60] NEGC also increased rate base by: (1) $960,739 in materials and supplies inventory; and (2) $2,160,500 for cash working capital allowance (Exh. NEGC-JMS-2, Sch. B (Rev.)).[61] As a result of these adjustments, NEGC derived a proposed rate base of $50,514,322 (Exh. NEGC-JMS-2, Sch. B (Rev.)). The Company's plant additions and the above-listed plant adjustments are discussed below.

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59 CIAC represents the amount paid by a customer or developer to the company as a contribution to the total cost of extending service to that customer. Customer contributions represent cost-free capital to the company and, therefore, CIAC is deducted from rate base. D.P.U. 08-35, at 40; Milford Water Company, D.P.U. 771 (1982).

60 The Company states that the allocated portion of plant and accumulated depreciation that benefits NEG Appliance have been removed from its rate base calculations (Exh. NEGC-JMS-1, at 7). This adjustment consists of a reduction of $224,398 in gross plant and a corresponding reduction of $43,577 to depreciation reserve (Exh. NEGC-JMS-2, Sch. B (Rev.)).

61 The Company indicated that in D.P.U. 08-35, the cash working capital requirement associated with purchased gas costs in the amount of $4,299,665 was included as a component of rate base resulting in an approved total rate base of $50,655,857 (RR-DPU-10, Att.; see D.P.U. 08-35, Sch. 4, at 266). In this case, the Company excluded purchased gas working capital from the base revenue requirement and included it in the revenue requirement recoverable through the GAF (RR-DPU-10). The Company explained that since this does not relate to base revenues or the base revenue requirement, the purchased gas working capital component was not included in its proposed calculation of the total rate base in this case (RR-DPU-10, Att). Thus, on a comparable basis, the proposed rate base in this case is $4,158,130 ($50,514,322 - $50,655,857 - $4,299,665) greater than the rate base approved in D.P.U. 08-35 (Exh. NEGC-JMS-2, Sch. B (Rev.); RR-DPU-10, Att.).

B. Plant Additions and Project Documentation

1. Introduction

Between January 1, 2008, and December 31, 2009, NEGC placed into service $11,843,419 of new plant, mostly related to distribution mains and services and transportation equipment (Exh. AG-1-2(7) at 18, 79, 122, 125, 143-144).[62] The Company states that its plant in service and accumulated depreciation balances amounts were obtained from its continuing property records and tied to the trial balance amounts for its Fall River and North Attleboro service areas as of December 31, 2009 (Exh. NEGC-JMS-1, at 7-8).

The Company states that during the years 2008 and 2009, it did not undertake any major revenue-producing projects to meet customer growth (Exhs. NEGC-JMSw-1, at 15; NEGC-JMS-1, at 8).[63] The Company, however, adds that over the same period it undertook non-revenue producing plant capital additions for various system integrity projects primarily involving the replacement of steel mains (Exhs. NEGC-JMSw-1, at 15; NEGC-JMS-1, at 8). The Company listed those capital additions with project total costs equal to or greater than $50,000, completed since December 31, 2007, which was the end of the test year of the

[62] Over the two-year period, mains, services and transportation equipment represented 29 percent, 33 percent, and 11 percent, respectively, for a total of 73 percent of total plant additions (Exh. AG-1-2(7) at 18, 79, 80, 122, 125, 143-144). Transportation equipment additions only occurred in 2009 (Exh. AG-1-2(7) at 144).

[63] The Department has distinguished between revenue-producing and non-revenue-producing plant in that revenue-producing plant additions are those additions intended to meet new or incremental customers' load, while non-revenue-producing plant additions are those additions intended to meet a utility's continuing service obligation to its existing customers. D.P.U. 03-40, at 40, 63.

Company's last rate case, D.P.U. 08-35 (Exhs. NEGC-JMSw-1, at 15; NEGC-JMSw-2; NEGC-JMS-3, WP C-7; RR-DPU-8).

This list includes seven[64] individual main replacement projects with actual costs ranging from $52,795 to $280,626, for a total cost of those seven projects of $1,012,546 (RR-DPU-8, Att. A at 1; Tr. 8, at 932).[65] The remaining projects in the list relate to computerized mapping; transportation billing software; the buyout of previously leased vehicles; and the purchase of other vehicles, radios, and meter reading equipment (Exh. NEGC-JMSw-1, at 15; RR-DPU-8, Att. A at 1).[66]

In addition, the Company provided a list of routine main replacement projects with estimated costs in excess of $50,000 but completed as part of a blanket authorization and not as individual projects (RR-DPU-8, Att B(2)). The Company explained that a blanket

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64 In its initial filing, the Company included only four of the seven projects in Exhibit NEGC-JMSw-2 but listed the three other projects in Exhibit EGC-JMS-3, WP C-7. In response to Record Request DPU-8, the Company updated Exhibit NEGC-JMSw-2 to include these three other projects.

65 The Company noted that of these seven projects, six would have been TIRF-related (Exh. DPU-NEGC-3-32; RR-DPU-8, Att. A at 1). The Company noted that while the Almy Road project in the town of Somerset was driven by leakage, the main was classified as cathodically protected pipe and therefore would have not been TIRF-related (Exhs. DPU-NEGC-32; DPU-NEGC-31, Att. (b) at 2).

66 These other projects in excess of $50,000 include: (1) multi-year project to develop computerized mapping of its distribution system ($540,118 as of December 31, 2009, and $852,403 as of December 31, 2007, for a total project cost of 1,392,521); (2) upgrades of software to comply with transportation billing tariffs ($182,783); (3) a buy-out of transportation equipment formerly on lease ($1,518,170); (4) replacement of meter reading hand-held devices ($51,211); (5) purchase of devices for automated meter reading equipment ($286,103); and (6) purchase of replacement electronic correctors ($226,194) (RR-DPU-8, Att. A).

authorization is similar to a regular work order authorization for an individual project except that a blanket authorization allows and sets up an account number for tracking any work done as part of a specific work category (Tr. 8, at 939-940).[67]

2. Positions of the Parties

The Company states that it obtained plant in service and accumulated depreciation trial balance amounts for its Fall River and North Attleboro service areas as of December 31, 2009 (Company Brief at 10, citing Exh. NEGC-JMS-1, at 7). The Company states that an adjustment was made for the cost of three projects that were functional and in service by the end of the test year, but had not yet been closed in the Company's accounting system (Company Brief at 10, citing Exh. NEGC-JMS-1, at 7). The Company explains that this adjustment affected plant in service, accumulated depreciation, and accumulated deferred income taxes (Company Brief at 10, citing Exh. NEGC-JMS-1, at 7).

The Company claims that among all projects that exceeded $50,000 and added to plant in service since NEGC's last rate case, there were no major projects relating to customer

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67 The Company indicated that, for example, it would have a blanket work order authorization for: (1) four-inch cast iron main replacements; (2) bare steel replacements; (3) service line replacements; and (4) miscellaneous and small projects (Tr. 8, at 939-940). The Company states that its use of blanket authorization is a fairly routine activity (Tr. 8, at 952). The Company, however, claims that as a result of the Department's Order in D.P.U. 08-35, it specifically identified starting in 2009 those mains replacement projects in excess of the $50,000 cost threshold, and accordingly used blanket work orders only for smaller projects (Tr. 8, at 952-953). The Company, explains that in 2008, when it ramped up its mains replacement activities in response to leaks in its system, it did not anticipate making the needed changes in work order authorization and therefore most of the mains replacement done in 2008 were still covered under blanket authorizations (Tr. 8, at 953).

growth during the last two years (Company Brief at 10, citing Exh. NEGC-JMS-1, at 8). The Company adds that the distribution plant projects were for various system integrity projects, including the replacement of bare steel and cast iron pipe, and that the remaining projects in excess of $50,000 relate to computerized mapping; transportation billing software; the buyout of previously leased vehicles; and the purchase of other vehicles, radios, and meter reading equipment (Company Brief at 10, citing Exh. NEGC-JMS-1, at 8). No other party commented on the Company's plant additions on brief.

3. Analysis and Findings

a. Introduction

For costs to be included in rate base the expenditures must be prudently incurred and the resulting plant must be used and useful to ratepayers. D.P.U. 85-270, at 20. The prudence test determines whether cost recovery is allowed at all, while the used and useful analysis determines the portion of prudently incurred costs on which the utility is entitled to a return. 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. D.P.U. 93-60, at 24-25; D.P.U. 85-270, at 22-23; Boston Edison Company, D.P.U. 906, at 165 (1982). A review of the prudence of a company's actions is not dependent upon whether budget estimates later proved to be accurate but rather upon whether the assumptions made were reasonable, given the facts that were known or that should have been known at the time. Massachusetts-American Water Company, D.P.U. 95-118, at 39-40 (1996); D.P.U. 93-60, at 35; Fitchburg Gas and Electric Light Company, D.P.U. 84-145-A at 26 (1985).

The Department has also found that a gas utility need not serve new customers in circumstances where the addition of new customers would raise the cost of gas service for existing firm ratepayers. D.T.E. 03-40, at 48; D.P.U. 88-67 (Phase I) at 282-284. The Department has stated that existing customers receive benefits whenever the return on incremental rate base exceeds the company's overall rate of return. D.P.U. 89-180, at 16-17.

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

Commission v. Department of Public Utilities, 352 Mass. 18, at 24 (1967).[68] In addition, the Department has stated that:

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

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

b. Non-Revenue Producing Plant

Of the seven mains replacement projects with costs in excess of $50,000, three of those projects have actual costs that are below the project budgeted amounts.[69] The Department has reviewed the documentation for those three projects, including the work orders, capital authorization, and closing reports. We find that those mains replacement projects are used and useful and that the Company incurred the costs in a prudent manner. Accordingly, we will allow the costs of these projects to be included in rate base.

The remaining four mains replacement projects showed cost over-runs that are at least 20 percent or greater. The first of these four projects is on Pleasant Avenue in Somerset

[68] The burden of proof is the duty imposed on a proponent of a fact whose case requires proof of that fact to persuade the fact finder that the fact exists, or where a demonstration of non-existence is required, to persuade the fact finder of the non-existence of that fact. D.P.U. 03-40 at 52 n.31, citing D.T.E. 01-56-A at 16; Fitchburg Gas and Electric Light Company, D.T.E. 99-118, at 7 (2001).

[69] These three projects are: (1) Lepes Road project in Somerset (Work Order No. 4020051095117); (2) Brightman Street Bridge project (Work Order No. 4951112811200); and (3) High Street project in Somerset (Work Order No. 4020051095116) (Exhs. NEGC-JMSw-2; NEGC-JMS-3, WP C-7; RR-DPU-8, Att. A at 1).

(Work Order No. 4020051095148), which replaced approximately 800 feet of two-inch high pressure bare steel main with eight-inch plastic main (Exh. NEGC-JMS-3, WP C-7; RR-DPU-8, Att. A at 1).[70] The total actual project cost was $105,168 with a cost over-run of $17,768 or 20.33 percent (RR-DPU-8, Att. A at 1, 12-13). The Department has reviewed the documentation for this project including the work orders, capital authorization, and closing reports (RR-DPU-8, Att. A, at 12-13). We find that this main replacement project is used and useful and that the Company incurred the costs in a prudent manner.[71] Accordingly, we will allow the cost of this project to be included in rate base.

The second of those four projects with a cost over-run is on Fisher Street Bridge, which replaced approximately 80 feet of twelve-inch cast iron pipe with twelve-inch steel/plastic main along Fisher Street in North Attleboro costing $52,794.61 (Work Order No. 4030060095138) (Exh. NEGC-JMS-3, WP C-7; RR-DPU-8, Att. A at 1, 20-22). The budgeted amount for this project is $40,000 based on the work order and capital authorization (RR-DPU-8, Att. A at 1, 20-22). Thus, this project had a cost over-run of $12,795 or 32 percent (RR-DPU-8,

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70 The project work order indicates that this main replacement project is a continuing effort by the Company to eliminate aged small-diameter high pressure steel main that has a history of leak repairs over the last several years and that the project includes the replacement of two services along with the tie-over of seven services (RR-DPU-8, Att. A at 1).

71 The Company's closing report, in the form of a Work Order Ledger Detail Report, shows the monthly entries for various cost categories from 2009 through 2010, for a total cost of $128,628.33 (RR-DPU-8, Att. A at 15-19). NEGC stated that the actual project cost of $105,168 represents the sum of the journal entries for 2009 and that "there were some paving costs . . . associated with repairing the highway crossing that would have occurred in 2010" (Tr. 8, at 935-936).

Att. A at 1). The Department has reviewed the documentation for this project, including the work order, capital authorization, and the journal entries of various cost categories in the Company's Work Order Ledger Detail Report (RR-DPU-8, Att. A at 23-25).[72] We find that this mains replacement project is used and useful and that the Company incurred the cost in a prudent manner. Accordingly, we will allow the cost of this project to be included in rate base.

The third of the four projects with a cost over-run is on Almy Road in Somerset (Work Order No. 4020051095119), which replaced approximately 1,400 feet of two-inch, high-pressure cathodically-protected bare steel mains with four-inch plastic mains (Exhs. NEGC-JMSw-2; AG-1-19, Atts. A, B at 4-6; DPU-NEGC-3-32). The actual cost of this project is $134,825 with a budgeted amount of $95,750, resulting in a cost over-run of $39,075 or 41 percent (Exh. DPU-NEGC-3-32, Att. (b) at 1-4; RR-DPU-8, Att. A at 1). The Company explained that the cost over-run was the result of several factors, including the installation of additional pipe footage, tie-ins of intersecting streets, traffic control, and paving (Exh. DPU-NEGC-3-31). The Department has reviewed the documentation for this project and accepts the Company's explanation for the cost over-run. We find that this mains replacement project is used and useful and that the Company incurred the cost in a prudent manner. Accordingly, we will allow the cost of this project to be included in rate base.

[72] The entries from August through December 2009 shown in the Company's Work Order Ledger Detail Report show all the components of the total cost of the project, including materials, labor, overhead, and direct costs with the vendors' names, invoice numbers, and costs billed (RR-DPU-8, Att. A at 23-25).

Finally, the fourth project with a cost over-run is listed as the Highland Avenue and Wilson Road project (Work Order No. 4950112810800), described as the replacement of an eight-inch bare steel main with an eight-inch plastic main (Exhs. NEGC-JMSw-2; AG-1-19, Att. A at 1; RR-DPU-8, Att. A at 1). The indicated actual cost of this project is $74,727 with no budgeted amount, thereby showing that the actual cost is the amount of cost over-run (Exhs. NEGC-JMSw-2; AG-1-19, Att. A at 1; RR-DPU-8, Att. A at 1). Under the same work order number with the same project description, however, the Company provided a copy of an unsigned work order authorization indicating “Addition Dollars” in the amount of $100 (Exh. DPU-NEGC-7-1, Att. at 1). This project was completed under a blanket work order, and the Company explained that this particular project involved road restoration, which included curb-to-curb resurfacing, restriping, and replacement of traffic signal wires (Exh. DPU-NEGC-3-31). No party commented on the proposed inclusion in rate base of the project cost on brief. We accept the Company’s representation that the project cost was incurred for road restoration after a main had been replaced. We find the plant addition to be used and useful and that the Company prudently incurred its cost. Accordingly, we allow the project cost to be included in rate base.

c. Discretionary Non-Revenue Producing Plant

We now turn to the six other projects with cost in excess of $50,000 that represent discretionary non-revenue-producing capital additions not related to mains replacement. Three of these projects show a cost over-run of at least 41 percent. We address below each of those three projects.

The first project is the SMS software upgrade application development (Work Order No. 4020050085071) with a budgeted amount of $130,004 and an actual cost of $182,783, resulting in a cost over-run of $52,779 or 41 percent (Exhs. NEGC-JMSw-2; AG-1-19, Att. A; RR-DPU-8, Att. A at 1). Despite repeated requests, the Company did not provide supporting documentation for the actual cost including a copy of the project closing report (see Exh. AG-1-19; DPU-NEGC-7-6; RR-DPU-8; RR-DPU-9; Tr. 8, at 927). Based on our review of the record, we find that the Company failed to meet its burden of proof demonstrating that the cost over-run of $52,779 was incurred in a prudent manner. D.T.E. 05-27-A at 40-48; D.T.E. 05-27, at 91-95. Nonetheless, we find that the plant addition is used and useful. Accordingly, we will allow the inclusion in rate base of the budgeted and authorized amount of $130,004 and exclude from rate base the project cost over-run of $52,779.

The second project is the purchase of electronic corrector instruments in the amount of $226,194 (Work Order No. 4020050085068) (Exhs. NEGC-JMSw-2; AG-1-19, Att. A; RR-DPU-8, Att. A at 1). The record shows that a capital authorization dated February 8, 2008, in the amount of $9,250 refers to this work order number and that the filed copy of such work order indicated an “Addition Dollars” of $100 compared to the indicated budget amount of $48,000 (Exhs. NEGC-JMSw-2; AG-1-19, Att. A; DPU-NEGC-7-1, Att.at 3, 5; RR-DPU-8, Att. A at 1). Despite repeated requests, the Company did not provide supporting documentation for the indicated budgeted amount or of actual costs, including a copy of the project closing report (see Exh. AG-1-19; DPU-NEGC-7-6; RR-DPU-8; RR-DPU-9; Tr. 8, at 927). We have no basis on this record to conclude that this cost was prudently incurred, nor can we determine whether the additional expenditure resulted in a used and useful plant addition. Based on our review of the record, we find that the Company failed to meet its burden of demonstrating that the project actual cost of $226,194 was actually incurred in a prudent manner. D.T.E. 05-27-A at 40-48; D.T.E. 05-27, at 91-95. Nonetheless, we find that the plant addition is used and useful. Accordingly, we will allow the inclusion in rate base of the budgeted and authorized amount of $9,250 and exclude from rate base the project cost over-run of $216,944 ($226,194-$9,250).

The third project is the purchase and buy-out of a number of leased vehicles in the total amount of $1,518,170 (for a total of 14 work orders) (RR-DPU-8, Att. A at 1).[73] The budgeted amount for this project is zero, which means that the indicated cost over-run is equal to the total cost of the project (RR-DPU-8, Att. A at 1). The record shows that during the test year, the Company was required to purchase leased vehicles it acquired under a lease agreement with Bankers Leasing because Bankers Leasing's new owner (GE Capital Commercial Inc.) had decided to exit this particular leasing business and exercised its right under the lease agreement to terminate the contract (Exh. DPU-NEGC-3-1, Att. A). Based on our review of the record, we find that the cost of the purchase of the leased vehicles was prudently incurred and that the vehicles are used and useful. Accordingly, we will allow the inclusion in rate base of the project total cost of $1,518,170.

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73 See Section V.C., Transportation and Work Equipment Expense, below.

The Company indicated that the remaining three of the six projects were under budget and that no cost over-runs were encountered. The first project was for the purchase of raptor radios in the total amount of $51,211 for a budgeted amount of $53,236 (Work Order No. 4020050075052) (Exhs. NEGC-JMSw-2; AG-1-19, Atts. A at 1, B at 18; RR-DPU-8, Att. A at 1). Based on our review of the supporting documentation including invoices, we find that the Company incurred the cost in a prudent manner and that the capital addition is used and useful. Accordingly, we will allow the total project cost of $51,211 to be included in rate base.

The second project is for the purchase of ERT meter reading remotes in the total amount of $286,103 with an indicated budget amount of $348,750, resulting in an under-budget amount of $62,647 (Exhs. NEGC-JMSw-2; AG-1-19, Att. A at 1; RR-DPU-8, Att. A at 1). The record, however, demonstrates that the copy of the work order as filed shows an amount of $78,750 and that the filed copy of the capital authorization also shows the same authorized amount of $78,750, calculated as the purchase of 1,500 meter reading remotes at $52.50 per remote (Exh. DPU-NEGC-7-1, Att. at 7-8).

Despite repeated requests, the Company did not provide copies of closing reports and other documentation as a basis to verify the indicated actual cost of $286,103 and the indicated budgeted amount of $348,750 (see Exhs. AG-1-19, Att. A at 1; DPU-NEGC-7-1; DPU-NEGC-7-6; RR-DPU-8; RR-DPU-9; Tr. 8, at 927). Thus, we find that the Company failed to meet its burden of proving that the cost in excess of the budgeted amount was incurred in a prudent manner. D.T.E. 05-27-A at 40-48; D.T.E. 05-27, at 91-95.

Nonetheless, we find that the plant addition is used and useful. Accordingly, we deny the amount of $207,353, representing the project cost over-run over the authorized amount of $78,750, and allow the inclusion in rate base of the budgeted and authorized amount of $78,750.

The third and last project that has an indicated actual cost below the budgeted amount is the Fall River GIS project, characterized as the multi-year project to develope computerized mapping for the Company's distribution system (Exhs. NEGC-JMSw-2; AG-1-19, Att. A at 1; RR-DPU-8, Att. A at 1). The record shows that the Company provided a copy of the capital authorization dated January 18, 2006, in the amount of $500,000 (Exhs. AG-1-19, Att. B at 7; DPU-NEGC-7-1, Att. at 9). This Fall River GIS project for 2006 is not a new project, but rather a continuation of the 2005 project, where the vendor (Integrated Mapping Services) agreed to keep and maintain its 2005 price (Exh. AG-1-19, Att. B at 8).[74] Based on our review of the record, we find that the Company incurred the project cost in a prudent manner and find the plant addition to be used and useful. Accordingly, we will allow the total project costs of $540,118 to be included in rate base.

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[74] The overall total cost of the GIS project is $1,392,521 with a budgeted amount of $1,500,000 for an indicated below budget cost of $107,479 (Exhs. NEGC-JMSw-2; AG-1-19, Att. A at 1; RR-DPU-8, Att. A at 1). This overall total project cost consists of two sub-total amounts: (1) $852,403 "Subtotal as of 12/31/07;" and (2) $540,118 "Subtotal as of 12/31/09" (Exhs. NEGC-JMSw-2; AG-1-19, Att. A; RR-DPU-8, Att. A at 1).

d. Other Non-Revenue-Producing Plant Additions

The Company provided a list of twelve other main replacement projects with estimated cost of each project in excess of $50,000, ranging from $55,750 to $342,769, for a total estimated amount for all these twelve projects of $1,367,124.09 (RR-DPU-8, Att. (B)(2) at 1).[75] For each project, the Company provided copies of the road map indicating the project's location, results of system pressure tests, daily contractor construction reports, and contractors' invoices (RR-DPU-8, Att. (B)(2)). The record shows that all these projects were undertaken and completed in 2008 and 2009 (RR-DPU-8).

Although these projects are in service as of December 31, 2009, and are considered used and useful, the Company could not provide the actual cost of each project (Tr. 8, at 946-947). The Company explained that these projects were completed as part of a blanket capital authorization, not as individual projects, and that it cannot break out amounts per project separately when something is charged under a blanket authorization (Tr. 8, at 946-947).

Five of these twelve projects have estimated project cost in excess of $100,000 (RR-DPU-8(B)(2)). If the Company cannot provide the actual cost of each of these projects, even when they have been completed and placed in service, a serious question is raised as to whether NEGC, during project implementation, will have effective monitoring and control over the overall projects costs to mitigate or prevent cost over-runs. For example, Project

75 Six of these projects replaced cast iron mains, five replaced non-cathodically protected bare steel mains, and one replaced a cathodically protected coated steel main (RR-DPU-8, Att. B(2)).

No. 2, which replaced approximately 1,600 feet of three- and four-inch cast iron mains with four-inch plastic mains in Winter Street in Fall River at an estimated cost of $156,066.60, shows a signed "Construction Project Change of Scope Form" dated April 16, 2008, with the description of change of scope as "split and remove ledge" (RR-DPU-8, Att. B(2) at 000023). The same "Construction Project Change of Scope Form" with the same description of the change of scope as "split and remove ledge," however, was done on five additional days: April 17, 2008, April 18, 2008, April 30, 2008, May 5, 2008, and May 6, 2008 (RR-DPU-8, Att. B(2) at 000025, 000027, 000033, 000037, 000039).

The Company witness explained that the use of change of scope forms for this project may have been overly formal, because the reasons for the overrun may have been associated with ledge removal (Tr. 8, at 944-945). Here, we will accept the Company's representation. Nonetheless, we note that this practice may also result in a less-efficient project documentation system. Accordingly, we direct the Company to address the documentation and project control issues as part of its next rate case.

Based on the foregoing discussions relating to discretionary non-revenue producing plant, we have excluded from rate base the following amounts: (1) $52,779 (SMS Software, Work Order No. 4020050085071); (2) $216,944 (Electronic Corrector Instruments, Work Order No. 4020050085068); and (3) $207,353 (ERT Meter Reading Remotes, Work Order No. 4020050075065), for a total of $477,076. In recognition of the Department's decision to exclude the above projects from NEGC's rate base, a corresponding adjustment to the Company's depreciation reserve is appropriate. D.P.U. 10-55, at 193-194; Aquarion Water

Company of Massachusetts, D.P.U. 08-27, at 16 (2009); D.T.E. 03-40, at 71. The above disallowances consist of $52,779 in Account 303, Miscellaneous Intangible Plant; and $424,297 in Account 381, Meters (RR-DPU-8, Att.). The Company has applied a depreciation rate of 6.67 percent for Account 303 and a composite rate of 3.38 percent for Account 381 during the period over which this plant was placed into service (Exh. NEGC-JMS-2, Sch. G-22 (Rev.)).[76] Therefore, to calculate the accumulated depreciation associated with each year, the Department has multiplied the respective depreciation rate by the respective period between the year the plant was installed and the end of the test year in this proceeding (i.e., two years for plant installed in 2008 and one year for plant installed in 2009). While the Company's capital authorizations indicate an in-service date of 2008 for the Account 381 disallowances, there is no information concerning the in-service date for the Account 303 disallowances (see Exhs. AG-1-19; DPU-NEGC-7-1, Att. at 3, 5). Therefore, the Department will assume an in-service date of 2008 for this plant investment. Based on this analysis, and using a half-year convention for plant placed in service during 2008, the Department finds that the associated depreciation reserve for ratemaking purposes associated with the Account 303 and Account 381 disallowances are $5,281 and $21,512, respectively, for a total of $26,793. Accordingly, the Department will reduce the Company's proposed depreciation reserve by $26,793.

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[76] NEGC applies separate depreciation accrual rates for meters in its Fall River and North Attleboro service areas (Exh. NEGC-JMS-2, Sch. G-22 (Rev.)). For purposes of this calculation, the Department has divided the Company's proposed depreciation expense associated with Account 381 by the year-end plant balance in Account 381.

Consistent with the above adjustments, a corresponding adjustment to the Company's deferred income tax reserve is also appropriate. D.P.U. 10-55, at 194; D.T.E. 01-56, at 42. In view of the complexities associated with deferred income tax calculations, the Department will derive a representative level of associated deferred income taxes by first dividing NEGC's total test year end accumulated deferred income tax reserve of $11,898,756 by its total net utility plant as of that date of $59,905,510 (Exh. NEGC-JMS-2, Sch. B). D.P.U. 10-55, at 194; D.T.E. 01-56, at 43. This produces a factor of 19.86 percent, which when multiplied by the total net plant being excluded from rate base of $477,076, produces a deferred income tax balance of $94,747. Accordingly, the Department will reduce NEGC's proposed deferred income tax reserve by $94,747.

Finally, in view of the above adjustments, it is necessary to eliminate from NEGC's proposed cost of service the depreciation expense associated with the disallowed plant additions. D.P.U. 10-55, at 194; D.P.U. 08-27, at 16; D.T.E. 03-40, at 71. To calculate the annual depreciation expense associated with this plant, the Department has multiplied the account-by-account plant disallowances by the corresponding depreciation accrual rates of 6.67 percent and 3.38 percent as determined above. Based on this analysis, the Department finds that the associated depreciation expense for the disallowed Account 303 and Account 381 plant is $3,520 and $14,341, respectively, for a total of $17,861. Accordingly, the Department will reduce NEGC's proposed depreciation expense by $17,861.

4. Conclusion

To facilitate the review of capital additions proposed for inclusion in rate base, companies must retain all necessary records, including work order authorizations and closing reports for each project, at least from the beginning of the calendar year after the test year of a company's last general rate case. Further, we emphasize that because of its TIRF, NEGC must maintain continuing and verifiable records for both TIRF-related and non-TIRF-related projects.[77] Careful recordkeeping practices can avoid the problems of proof encountered in this proceeding. Otherwise, the Company risks incapacitating problems of proof and consequent denial of cost recovery.

In addition, since all of those twelve projects would have been TIRF-related, NEGC, under its existing project recordkeeping, accounting, and financial system, may not be able to provide the actual cost of this type of project funded under a blanket capital authorization in determining its annual TIRF revenue requirement. Even if the project direct costs, such as the cost for Project No. 2 shown on pages 000059 through 000063 in Attachment B(2) of Record Request DPU-8, represent the majority of the project costs as NEGC claimed, there are other overhead and indirect costs associated with each project that the Company needs to accurately isolate for determining the actual project cost for inclusion in the TIRF mechanism (Tr. 8, at 947-948).

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[77] In the case where a company is acquired or merged during the intervening period between rate cases, the surviving company shall be responsible for preserving and maintaining such records.

Accordingly, we will allow the Company to include in its annual TIRF revenue requirement only individual projects that are completed and closed with separate capital authorization. If a completed TIRF-related project is authorized under a blanket capital authorization, the Company may not include the cost of such a project in the TIRF annual revenue requirement, but may propose for its inclusion in rate base such plant addition in its next base rate proceeding.

Each TIRF-related project proposed for inclusion in the annual TIRF revenue requirement must be supported with documentation that includes, but is not limited to: (1) a signed work order[78] with a detailed project description, including the project street address and town location, length of mains, type of materials to be replaced, and the replacement materials used; (2) a signed capital authorization request detailing among other items how the project budget or amount of capital authorized was determined; (3) a closing report indicating, among other things, the actual direct and indirect overhead and burden costs associated with the project as well as the date when the plant addition was placed in service; and (4) a variance analysis that provides dollar and percentage calculations of any cost over-runs providing supporting documentation and explanation for such cost over-runs.

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78 For example, under NEGC's documentation in this case, Work Order numbers 4020051095117, 4020051095119, 4Z7158830CONSL, 4020050085071, and 4020050075052 have no name and signature on the "Route For Approval" section of Work Order Authorization Information form (Exh. AG-1-19, Att. B at 3, 6, 9, 17, 18). Similarly, Work Order numbers 4020051095116, 4020051095148, and 4030060095138 have no name and signature on the "Route for Approval" section (RR-DPU-8, Att. A at 2, 12, 20). Thus, there is no record as a basis to identify the particular person responsible for the project under a given work order.

Also, we direct NEGC to modify its work order, capital authorization, and closing report forms to clearly indicate that a capital project is TIRF-related or non-TIRF-related. In addition, we direct the Company to maintain continuing and verifiable records for both the TIRF-related and non-TIRF-related projects. See D.P.U. 10-55, at 184-185.

We leave it to the Company's discretion on the additional content, structure, and configuration of documentation it deems necessary and appropriate to be filed in its annual TIRF compliance filings in order to meet the Department standards of prudence and used and usefulness.[79] Given the short period of review for the Company's annual TIRF compliance filings, as opposed to the period of review in a general rate case proceeding, failure of the Company to file complete, reviewable, and cohesive documentation would increase the risk of exclusion of the cost of a project for recovery in the TIRF annual revenue requirement.

C. Contributions in Aid of Construction

1. Introduction

As of the end of the test year, NEGC reported a total CIAC balance of $2,866,871 (Exh. NEGC-JMS-2, Sch. C). The CIAC is entirely associated with distribution plant, of which most is associated with mains and services (Exhs. NEGC-JMS-2, Sch. C; AG-9-5).[80] In its initial filing, the Company reduced its gross plant by the CIAC balance of $2,866,871

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[79] For an illustration of the content, structure and configuration of an appropriate documentation, see D.P.U. 10-55, Stamp-Approved Compliance Filing, Exh. NG-BOS-12-3 (November 18, 2010).

[80] The CIAC associated with mains and services was $1,358,447 and $1,429,630, respectively, for a total of $2,786,077 or 97.3 percent of the total CIAC adjustment on gross plant of $2,866,871 (Exh. NEGC-JMS-2, Sch. C).

(Exh. NEGC-JMS-2, Schs. B, C). During the proceeding, the Company determined that its Fall River service area had received an additional $184,888 in CIAC between February 1999 and August 2003 (Exhs. AG-3-5; AG-9-5).[81] Accordingly, NEGC filed updated calculations to incorporate the revised CIAC balance of $3,051,759 (Exh. NEGC-JMS-2, Schs. B (Rev), C (Rev.)).[82]

2. Positions of the Parties

The Attorney General argues that the Company should be directed to reduce its proposed rate base by the approximately $185,000 in additional CIAC (Attorney General Brief at 65, citing Exh. AG-9-5). The Attorney General contends that NEGC has not disputed this proposed adjustment (Attorney General Brief at 65). In addition, the Attorney General claims that the inclusion of this CIAC as an offset to rate base will reduce the Company's pro forma depreciation expense by $7,000 and, therefore, depreciation expense should be reduced (Attorney General Brief at 64, citing Exh. AG-DJE-1, at 16). No other party commented on this matter on brief.

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81 The Company stated that in 2006, its divisional management located in Rhode Island decided to close CIAC associated with completed projects against related plant in services balances (Exh. AG-9-5). The Company added that pursuant to the Department's directives regarding the appropriate accounting treatment of CIAC in New England Gas Company, D.P.U. 07-46 (2007), the Company reinstated CIAC as a separate account (Exh. AG-9-5).

82 Because the supporting details associated with CIAC receipts are not readily available for that period, NEGC allocated 32 percent of the additional CIAC to services and 68 percent to mains, based on the ratio of CIAC to mains and services in the Fall River service area as of the end of the test year (Exh. AG-9-5). Therefore, the Company credited its mains and services plant balances by $59,164 and $125,724, respectively (Exhs. NEGC-JMS-2, Sch. C-1 (Rev.), column (c), lines 22 and 26; AG-9-5).

3. Analysis and Findings

A utility company may request a customer to contribute a portion of the cost required to extend the company's lines to that customer. Under long-standing Department practice, property that has been contributed to a utility is not included in rate base. This 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 return on rate base. Milford Water Company, D.P.U. 771, at 21 (1982); Oxford Water Company, D.P.U. 18595, at 18 (1976); Commonwealth Gas Company, D.P.U. 18545, at 2 (1976). Consistent with this policy, the Department does not permit depreciation expense on contributed property. 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 (1984).

Regarding the Attorney General's request that NEGC be directed to increase its CIAC balance to recognize the additional CIAC, companies are under an obligation to ensure that their accounting records are accurate and to correct any errors that are found. Plymouth Water Company, D.T.E./D.P.U. 06-53, at 10 (2008); Boston Edison Company, D.T.E. 97-95, at 92-93 (2001). In this case, the Company has identified additional CIAC that had been previously unrecorded, and has revised its records accordingly (Exh. AG-9-5). The Department has examined NEGC's calculations and finds that the proposed adjustments, including the apportionment of CIAC to mains and services accounts, result in a more accurate representation of the Company's plant balances. In addition, the Company has revised its cost of service schedules by increasing CIAC by $184,888 (Exh. NEGC-JMS-2, Schs. B (Rev.), C-1 (Rev.)). The Department finds that the Company has properly accounted for the additional CIAC for ratemaking purposes. Accordingly, we accept the Company's proposed adjustment to rate base.[83]

D. Materials and Supplies

1. Introduction

In its initial filing, the Company included in its proposed rate base the amount of $960,739 representing the 13-month (December 2008 through December 2009) average of its inventory of materials and supplies (Exhs. NEGC-JMS-2, Sch. B; NEGC-JMS-3, WP B-2). During the proceedings, the Company discovered an error in its December 31, 2008 material and supplies balance (Exhs. NEGC-JMS-3, WP B-2; DPU-NEGC-7-7, Att. C). The Company corrected the error, thereby producing a revised materials and supplies balance of $961,175 (Exh. DPU-NEGC-7-7). No party commented on the Company's proposal.

2. Analysis and Findings

Utilities keep on hand various materials and supplies for use in the course of normal operations. It has been a long-standing practice of the Department to include in a utility's rate base a representative level of its materials and supplies balance. Boston Edison Company, D.P.U. 19991, at 16 (1979). The Department allows this adjustment to compensate a utility for the cost associated with carrying its inventory. Because of the month-to-month fluctuations in this account, a 13-month average balance is used. See Housatonic Water Works Company,

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83 The Department will address the Attorney General's proposal to reduce the Company's proposed depreciation expense by $7,000 in Section V.L., below.

D.P.U. 86-235, at 3-4 (1987); High Wood Water Company, D.P.U. 1360, at 7-8 (1983); Western Massachusetts Electric Company, D.P.U. 1300, at 29 (1983). We find that the Company has properly calculated its revised material and supply balance of $961,175. Accordingly, the Department accepts the Company's proposed materials and supplies adjustment to rate base.

E. Cash Working Capital

1. Introduction

In their day-to-day operations, utilities require funds to pay for expenses incurred in the course of business, including operating and maintenance ("O&M") expenses. These funds are either generated internally by a company or obtained 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 in determining a company's rate base.

Cash working capital needs have been determined through either the use of a lead-lag study or a 45-day O&M expense allowance. D.T.E. 03-40, at 92. In the absence of a lead-lag study, the Department has generally relied on the 45-day convention as reasonably representative of O&M working capital requirements. D.T.E. 05-27, at 98; D.P.U. 88-67 (Phase 1) at 35. The Department, however, has expressed concern that the 45-day convention first developed in the early part of the 20th century no longer provides 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). Therefore, the Department requires each gas and electric distribution company to either (1) conduct a lead-lag study where cost-effective, or (2) propose a reasonable alternative to a lead-lag study to develop a different interval. D.T.E. 03-40, at 92; D.T.E. 02-24/25, at 57.

NEGC conducted a lead-lag study to determine its O&M cash working capital requirements (Exhs. NEGC-JMS-1, at 9-10; NEGC-JMS-2, Sch. D (Rev)).[84] The Company explains that the lead-lag study determines the revenue lag, which is the weighted average length of time in days from the provision of utility service to the receipt of payments for that service from customers (Exh. NEGC-JMS-1, at 9). The lead-lag study also determines the expense lead, which is the weighted average length of time in days from the receipt of services by NEGC to its payment date for those services (Exh. NEGC-JMS-1, at 9). The average lag days in excess of average lead days, or the net lag days, mean that the Company receives payment for utility service later than it pays for materials and services from others to provide that utility service (Exh. NEGC-JMS-1, at 9). The resulting net lag days multiplied by the Company's average daily expenses represents the ongoing average level of cash investment required by NEGC for the provision of utility service (Exh. NEGC-JMS-1, at 9).

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[84] The Company noted that its proposed amount of cash working capital to be added to rate base does not include the carrying cost associated with purchased gas expense because such carrying cost is recoverable through the Company's gas adjustment factor (Exh. NEGC-JMS-1, at 9-10).

To determine its proposed cash working capital allowance, NEGC first calculated a revenue lag of 66.49 days.[85] The revenue lag consists of (1) a 15.17 day meter reading lag, (2) a 3.56-day billing lag, and (3) a 47.76 day collection lag (Exhs. NEGC-JMS-2, Sch. D (Rev.); NEGC-JMS-3, WPs D-2, D-3, at 6). Next, the Company identified $18,678,995 in adjusted O&M expense (i.e., proposed operating expenses less pension and post-retirements, uncollectible expense, depreciation, property taxes, and payroll taxes) (Exh. NEGC-JMS-2, Sch. D (Rev.)). The Company then categorized the adjusted O&M expense into eight categories, five of which pertained to payroll and associated benefits expense, along with categories for (1) insurance premiums, (2) professional fees, and (3) other O&M expense (Exh. NEGC-JMS-2, Sch. D (Rev.)). The Company then calculated an expense lag for each of the above expense categories by analyzing the number of days from the midpoint of the month during which the particular expense by category was incurred and NEGC's own payments to suppliers (Exh. NEGC-JMS-3, WPs D-6 through D-12). The net difference between the revenue lags and expense lags, weighted by the pro forma expense for each category, produced an average expense lead of 24.27 days, and an average net lag of 42.22 days (Exh. NEGC-JMS-1, at 9; NEGC-JMS-2, Sch. D (Rev.); NEGC-JMS-3, WP D-1). This net lag factor of 42.22 days, multiplied by the $18,678,995 in proposed O&M expense, produces a working capital component of $2,106,951 (see Exh. NEGC-JMS-3,

[85] The Company's initial filing showed a revenue lag of 68.09 days (Exhs. NEGC-JMS-1, at 9; NEGC-JMS-2, Sch. D). The Company subsequently reduced this revenue lag by 1.60 days due to an inadvertent error in its initial calculations (Exh. NEGC-JMS-2, Sch. D (Rev.); RR-DPU-31).

WP D-5). NEGC then added $53,549 in working capital allowance attributed to uncollectible expense associated with the proposed increase, and concluded that its total O&M cash working capital requirement was $2,160,500 (see Exh. NEGC-JMS-3, WP D-5).

Finally, NEGC calculated a purchased gas working capital allowance (Exh. NEGC-JMS-1, at 10). Using the same approach as described above to calculate its expense leads, the Company determined that the appropriate expense lead for purchased gas was 43.39 days (Exh. NEGC-JMS-3, WP D-5). The Company's revised revenue lag of 66.49 days, less the purchased gas expense lead of 43.39 days, produces a net lag of 23.10 days (Exh. NEGC-JMS-2, Sch. D (Rev.)).

2. Positions of the Parties

NEGC contends that its lead-lag study was calculated in recognition of the Department's concern that the former 45-day convention no longer provided a reliable measure of a company's cash working capital requirements (Company Brief at 11-12). The Company maintains that while its lead-lag study initially resulted in a net lag of 43.82 days, NEGC has further reduced this net lag to 42.22 days in recognition of a calculation error in the collection lag component (Company Brief at 12, citing RR-DPU-31). No other party commented on this matter on brief.

3. Analysis and Findings

If properly designed, lead-lag studies are an appropriate method to determine cash working capital. Lead-lag studies, however, are complex and costly to undertake. Not wanting to require expensive lead-lag studies, the Department has encouraged utilities to consider and offer other cost-effective methods to produce lower working capital requirements than the traditional 45-day convention. D.T.E. 03-40, at 92; D.T.E. 02-24/25, at 55; D.T.E. 98-51, at 15.

In the present case, NEGC conducted separate lead studies for both purchased gas and O&M expenses using an outside consultant (Exh. NEGC-JMS-1, at 9). The Company has proposed to apply the results of these studies to meet its cash working capital needs, through a purchased gas net lag factor of 42.23 days and a net lag factor of 24.70 days (Exh. NEGC-JMS-2, Sch. D (Rev.); RR-DPU-31). When we compare the normalized cost of preparing the lead-lag studies to the effect the lower cash working capital factor has on revenue requirements, we conclude that the Company's decision to perform a lead-lag study was a cost-effective means to determine its working capital needs.

In D.P.U. 08-35, at 35, the Department noted that the Company had included purchased gas expense in its cash working capital requirement calculations, and stated that it is more efficient for cash working capital associated with purchased gas and O&M expenses to be calculated separately. Here, NEGC has provided separate calculations for purchased gas and O&M expense (Exhs. NEGC-JMS-1, at 9-10; NEGC-JMS-2, Sch. D (Rev.); NEGC-JMS-3, WP D-5). NEGC calculated a net purchased gas lead of 23.10 days, which is equal to the 66.49 revenue lag days less 43.39 expense lead days associated with gas purchases (Exhs. NEGC-JMS-2, Sch. D (Rev.); NEGC-JMS-3, WPs D-5).

The Department has examined NEGC's lead-lag studies, including the various revenue lag components. The Company's proposed meter reading lag component is identical to that approved in its previous rate case. D.P.U. 08-35, at 30.[86] NEGC's proposed collection lag component of 47.76 days is 1.27 days greater than the 46.49-day collection lag that the Company filed in its last rate case (Tr. 4, at 501). See D.P.U. 08-35, at 30. The Company explains that because of the downturn in economic conditions prevailing during 2009, customers may have been relatively slower in paying their bills (Tr. 4, at 501, 503-504). Based on NEGC's explanation and the Department's general familiarity with economic conditions, we accept the Company's proposed collection lag component of 47.76 days.

Regarding its proposed 3.56-day billing lag component, this average billing lag is 0.12 days more that the 3.44-day average billing lag proposed by the Company in its last rate case, and 1.44 days greater than the 2.12-day average billing lag ultimately approved by the Department in that proceeding. See D.P.U. 08-35, at 35-37. The Department criticized NEGC in its previous rate case for what was considered to be an excessive delay of upwards to eight days between meter readings and actual billing. D.P.U. 08-35, at 35. In this case, the Department finds that in addition to weekends and holidays that were considered in establishing the 2.12-day billing lag factor, vacation schedules, sick leave, and weather conditions also affected the billing lag and, thus, must be taken into account (Exh. AG-5-7). Moreover, given the physical nature of meter reading, the Department recognizes that the Company's eight meter readers are more susceptible to illness and injury than other employees, which affects

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86 To make the most efficient use of its metering and billing systems, the Company organizes its meter routes on the basis of 22 cycles per month with twelve days per cycle for a total of 264 reading and billing days (Exh. NEGC-JMS-3, WP D-3, at 1-6). See D.P.U. 08-35, at 36.

the meter reading and billing schedule (Exh. AG-5-7). In view of these considerations, the Department accepts NEGC's proposed billing lag of 3.36 days. Finally, the Company has included $3,859 in interest on customer deposits in its cash working capital allowance calculation (Exh. NEGC-JMS-2, Schs. A, D, G-1). Because customer deposits represent a cost-free source of capital to a utility, it is inappropriate to require customers to reimburse NEGC for working capital on funds that customers have provided. See D.P.U. 906, at 24. Therefore, the Department has removed this expense from the Company's cash working capital allowance.

Based on the above analysis, the Department finds that NEGC's proposed purchased gas working capital lead of 23.10 days and proposed O&M expense working capital lead of 42.22 days provide a reliable basis on which to calculate the Company's cash working capital requirements. Application of these lead-lag factors to the levels of O&M expense authorized by this Order produces a cash working capital allowance of $2,115,216. The effect of this cash working capital factor on the Company's revenue requirement is provided in the schedules attached to this Order. The purchased gas net lag factor of 23.10 days is to be used by NEGC in calculating the purchased gas working capital recovered through the CGAC.

F. Customer Deposits

1. Introduction

The Company's test year-end balance in customer deposits was $401,983 (Exhs. NEGC-JMS-1, at 10; NEGC-JMS-2, Sch. G-9 (Rev.)). The Company proposed to reduce its rate base by this amount (Exhs. NEGC-JMS-1, at 10; NEGC-JMS-2, Sch. B (Rev.)).[87] No party commented on the Company's proposal on brief.

2. Analysis and Findings

Customer deposits are refundable amounts held against future bills that may go unpaid when an account is closed. D.T.E. 02-24/25, at 25; Boston Edison Company, D.P.U. 1720, at 90-91 (1984); D.P.U. 906, at 24. Similarly, customer advances, also known as refundable construction advances, are refundable amounts given to the utility by a customer or potential customer for the purpose of constructing facilities intended to serve that particular customer. D.T.E. 03-40, at 102-103; D.T.E. 02-24/25, at 29; D.P.U. 1590, at 10; Western Massachusetts Electric Company, D.P.U. 18370, at 5 (1977).

Because customer deposits and customer advances provide the utility with cost-free sources of capital, the Department requires that customer deposits and customer advances be included as offsets to rate base. The offset is calculated by using the year-end balance of the customer deposit and customer advance accounts. D.P.U. 86-235, at 5; D.P.U. 1590, at 10-11; D.P.U. 906, at 24. The Department finds that the Company's proposed customer deposit offset to rate base is consistent with Department precedent. Accordingly, the Department accepts the Company's proposed customer deposit offset.

87 The Company has also proposed to annualize the test year interest expense paid on customer deposits (see Section V.D., below).

G. Accumulated Deferred Income Taxes

1. Introduction

As of the end of the test year, NEGC had on its books a total accumulated deferred federal and state income tax balance of $11,897,011 (Exh. NEGC-JMS-3, WP B-3). Deferred income taxes represent the cumulative effect of the difference between income taxes that are calculated using financial accounting depreciation methodologies on the Company's books and income taxes using depreciation methodologies specified by the Internal Revenue Service ("IRS") (Exhs. NEGC-JMS-1, at 10; DPU-NEGC-7-11). NEGC has proposed to increase its year-end deferred income tax balance by $1,745 to recognize previously unrecorded deferred income taxes associated with plant investment that the Company considered to be functionally completed in November and December 2009 (Exh. NEGC-JMS-3, WP C-7). Consequently, the Company proposes to apply a total deferred income tax balance of $11,898,756 as an offset to rate base (Exh. NEGC-JMS-2, Sch. B (Rev.)).

On September 21, 2009, the IRS issued Revenue Procedure 2009-39 ("Rev. Proc. 2009-39"). Under Rev. Proc. 2009-39, § 2.08.93, among other things, a taxpayer may change its method of accounting from capitalizing its costs paid or incurred to repair and maintain tangible property to treating the repair and maintenance costs as ordinary and necessary business expenses. The taxpayer can obtain consent for the change with the submission of specific statements regarding the repair and maintenance costs at issue. Rev. Proc. 2009-39, § 2.08.93. Any tax deduction taken as a result of this accounting change would be subject to IRS review, audit, and possible disallowance. Treating these costs as ordinary and necessary business expenses allows for a tax deduction of the entire expense incurred in that year. In contrast, capitalizing the costs spreads out the expense and the tax deduction over the capitalization period, thereby allowing for a partial tax deduction of a portion in each year of the capitalization period. Western Massachusetts Electric Company, D.P.U. 10-70, at 187 (January 31, 2011).

Southern Union, as the taxpaying entity for NEGC, has not filed for an application for change in accounting method, with respect to Rev. Proc. 2009-39, § 2.08.93, for its gas distribution utility assets (Exh. AG-5-8). The Company expects that the IRS will issue guidelines on this matter that are specifically applicable to gas distribution companies in the future (Exh. AG-5-8). At that time, NEGC anticipates that Southern Union will compute whatever adjustment is deemed permissible in the manner prescribed by the IRS and, thereafter, file an application to change its accounting method (Exh. AG-5-8).

2. Attorney General Proposal

The Attorney General proposes that the Department increase the balance of accumulated deferred income taxes by $3,660,000 (Attorney General Reply Brief at 17). To arrive at her proposal, the Attorney General assumed that the immediate impact of implementing the Rev. Proc. 2009-39, § 2.08.93 change in tax accounting on the Company's revenue requirement would be through an IRS Section 481(a) adjustment (Exh. AG-DJE at 21). The Attorney General noted that the adjustments for utility companies that have already implemented Section 481(a) have ranged between four percent and 14 percent of their respective gross distribution plants (Exh. AG-DJE at 20).

The Attorney General outlined two scenarios for NEGC. For the first scenario, she assumed that a Section 481(a) filing by the Company would produce an adjustment equal to five percent (Exh. AG-DJE at 21). Applying this percentage on the Company's gross distribution plant in service as of the end of 2009, results in a Section 481(a) adjustment of $4,779,000 (Exh. AG-DJE at 21, Sch. DJE-5). Then the Attorney General applied the combined tax rate of 38.29 percent on this estimated adjustment, giving an increase to the Company's accumulated deferred income taxes of $1,830,000 and a corresponding reduction in revenue requirement of $227,000 calculated at the Company's proposed pre-tax rate of return (Exh. AG-DJE at 21, Sch. DJE-5).

For the second scenario, the Attorney General assumed that a Section 481(a) filing by NEGC would produce an adjustment equal to ten percent (Exh. AG-DJE at 21). Applying this percentage on the Company's gross distribution plant in service as of the end of 2009, results in a Section 481(a) adjustment of $9,559,000 (Exh. AG-DJE at 21, Sch. DJE-5). Then the Attorney General applied the combined tax rate of 38.29 percent on this estimated adjustment, giving an increase to the Company's accumulated deferred income taxes of $3,660,000 and a corresponding reduction in revenue requirement of $454,000 calculated at the Company's proposed pre-tax rate of return (Exh. AG-DJE at 21, Sch. DJE-5).

3. Positions of the Parties

a. Attorney General

The Attorney General contends that ratepayers should not be burdened by the failure of the Company to avail itself of the IRS's expanded tax deductions for repair and maintenance activities (Attorney General Brief at 65). The Attorney General claims that the available benefits from the expansion of the repair allowance deductions are substantial, and that many regulated utilities have already implemented the tax accounting change, resulting in significant tax savings (Attorney General Brief at 66, 68, citing Exh. AG-DJE at 19-20).[88]

The Attorney General claims that the Company did not provide analysis of the potential risks associated with availing itself of the expanded repair allowance deductions as opposed to the benefits that could be derived from such deductions (Attorney General Brief at 67). The Attorney General claims that the cash flow benefit to the Company is real, and will continue to grow from year-to-year as the cash flow benefits of additional repair deductions accumulate (Attorney General Brief at 67). The Attorney General contends that by declining to implement the tax change, the Company has chosen to request that customers pay higher rates instead of making an effort that would reduce its revenue requirement (Attorney General Brief at 67).

The Attorney General rejects the Company's argument that any expanded income tax deductions for repairs and maintenance would be subject to IRS audit and modification, and is thus not known and measurable (Attorney General Reply Brief at 14, citing Company Brief

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88 The Attorney General, for example, claims that in D.P.U. 10-55, National Grid's United States parent, National Grid Holdings, Inc., recorded a one-time tax expense of $2.3 billion for repair and maintenance costs in its fiscal year 2009 federal income tax return as a result of the expansion in the allowable deductions for repairs (Attorney General Brief at 66, citing Exh. AG-DJE-1, at 19). The Attorney General claims that the resulting net cash tax benefit attributed to Boston Gas Company was $74 million (Attorney General Brief at 66, citing D.P.U. 10-55, Exh. NG-MDL-1, at 46). The Attorney General adds that this cash tax benefit implies a tax deduction equal to approximately nine percent of that company's gross utility plant in service (Attorney General Brief at 66, citing Exh. AG-DJE-1, at 19).

at 36). The Attorney General claims that virtually every income tax deduction is potentially subject to audit and modification (Attorney General Brief at 68). Moreover, the Attorney General points out that the potential risk of an audit did not prevent National Grid, by way of example, from deducting the deferred taxes related to the repair allowance from rate base in the most recent rate proceeding for its gas utility subsidiaries (Attorney General Brief at 67; Attorney General Reply Brief at 14, citing D.P.U. 10-55, Tr. 7, at 894). The Attorney General contends that if the deferred taxes related to the repair allowance were known and measurable for National Grid, they should also be known and measurable for NEGC (Attorney General Reply Brief at 14).

The Attorney General contends that the Department should recognize the availability of such repairs and maintenance allowance deductions by reducing the Company's rate base and cost of service to reflect those deductions (Attorney General Brief at 68). Reasoning that this tax deduction for other utilities ranged between four percent and 14 percent of gross plant, the Attorney General suggests that using an allowance of ten percent for the Company would be reasonable (Attorney General Brief at 68). The Attorney General calculates that a ten percent repair and maintenance allowance would increase the Company's accumulated deferred income tax reserve by $3,660,000 (Attorney General Brief at 68). Thus, the Attorney General recommends that the Department increase the Company's deferred income tax balance accordingly (Attorney General Brief at 68).

b. Company

NEGC opposes the Attorney General's proposal to reduce the Company's rate base by $3,660,000 to impute the effect of the IRS's repair deduction allowance (Company Brief at 35-36). The Company asserts that the Attorney General's recommended tax deduction is not known and measurable and must be rejected (Company Brief at 36). According to NEGC, based on the recent experience of another company, Energen, and its lack of success in sustaining the repair and maintenance deduction during an IRS audit, considerable uncertainty remains as to what deductions the IRS will accept (Company Brief at 36, citing Exh. AG-9-20 (Supp); Tr. 8, at 1059; Company Reply Brief at 16).[89] The Company claims that it is not clear as to what amount it will be allowed to deduct for tax purposes related to repair deductions, and accordingly, NEGC did not make an estimate (Company Brief at 36, citing Exh. AG-5-9).

The Company claims that there is a significant difference between the level of certainty surrounding long-established income tax deductions and deductions associated with this more recent repair tax allowance (Company Reply Brief at 16). The Company states that by weighing the risks and costs of modifying its tax accounting methodologies, before definitive guidance has been established from the IRS or established through litigation, it has taken a cautious and prudent course of action (Company Reply Brief at 16). In contrast, NEGC notes

[89] The Company asserts that such uncertainty in the tax treatment is affirmed by Southern Union's vice president of tax and co-chairman of the joint AGA/INGAA tax committee, who indicated that there is "considerable uncertainty" as to what the IRS will accept (Company Brief at 36, citing Exh. AG-9-20 Supp.; Tr. 8, at 1059, 1067; Company Reply Brief at 5).

that companies that have made an effort to compute these repair deductions in the absence of definitive guidance from the IRS are now in the process of resolving the issue through the court system at additional cost to those companies, because the IRS has contested the changes being filed by those taxpayers (Company Reply Brief at 16, citing Tr. 8, at 1059).[90] NEGC further claims that, although the Attorney General proposed an amount to adjust the Company's rate base, she also conceded that it was uncertain what the exact amount would be because it might be subject to audit and modification (Company Brief at 36, citing Tr. 7, at 893).

NEGC argues that there is no basis for the Department to substitute its judgment over that of the Company in terms of assessing the degree of uncertainty associated with the allowable computation of these additional tax deductions (Company Reply Brief at 15). Instead, the Company contends that "the Department must base its decisions on substantial evidence and cannot simply speculate as to the existence of some future fact" (Company Reply Brief at 16, citing Boston Gas v. Department of Telecommunications & Energy, 436 Mass. 233, 239 (2002)). The Company further argues that the Department has rejected the use of similar assumptions regarding income taxes, because the assumptions are not known and measurable (Company Reply Brief at 16-17, citing Bay State Gas Company, D.P.U. 92-111, at 71 (1992)). NEGC concludes that the Attorney General's recommendation

[90] The Company claims that the IRS has designated this repair tax accounting method issue as a "Tier 1" issue, which represents the IRS's highest level of alert regarding a tax issue in cases where the IRS disagrees with taxpayers (Company Reply Brief at 16, citing Tr. 8, at 1059).

is not known and measurable and, therefore, should be rejected by the Department (Company Brief at 36, citing Exh. AG-9-20; Tr. 8, at 1061; Company Reply Brief at 17).

4. Analysis and Findings

Deferred income taxes arise because of differences between the tax and book treatment of certain transactions, including the use of accelerated depreciation and the treatment of certain operating expenses for income tax purposes. D.P.U. 10-55, at 205; Fitchburg Gas and Electric Light Company, D.T.E. 99-118, at 33 (2001); Essex County Gas Company, D.P.U. 87-59, at 27 (1987). The year-end balance of deferred income taxes represents a cost-free source of funds to the utility and is thus treated as an offset to rate base. D.P.U. 87-59, at 63; AT&T Communications of New England, D.P.U. 85-137, at 31 (1985); Boston Edison Company, D.P.U. 1350, at 42-43 (1983).

As an initial matter, we determine that the record supports NEGC's proposal to increase its year-end deferred income tax balance by $1,745 to recognize previously unrecorded deferred income taxes associated with plant investment that the Company considered to be functionally completed in November and December 2009 (Exh. NEGC-JMS-3, WP C-7). With respect to the expanded tax deduction allowance under Rev. Proc. 2009-39, § 2.08.93, there are uncertainties, risks, and costs associated with modifying a company's tax accounting methodologies before definitive guidance has been established by the IRS or through litigation. The Attorney General noted that while other companies have taken advantage of the expanded tax deduction allowance under Rev. Proc.

2009-39, § 2.08.93, the actual impact for any company would depend on the particular circumstances of that company (Exh. AG-DJE at 21).

Based on our review of the record in this case, we find that the Attorney General's proposal to increase the Company's deferred income taxes by $3,660,000 arising from the expanded repair allowance deductions under IRS regulations is speculative at this time. D.P.U. 10-70, at 191. The Attorney General's assumption that a ten percent Section 481(a) adjustment would be applicable to the Company's gross distribution plant lacks any evidentiary basis, other than the fact that this percentage falls within the four percent to 14 percent range of adjustments used by other utility companies (Exh. AG-DJE at 20). In addition, such a proposed adjustment utilizes only one of the two main components of the above-noted tax accounting change.[91] Aside from not having made any filing to modify its tax accounting method, the Company during the test year did not perform any calculations nor provide any estimates on the appropriate adjustment that might be deemed permissible by the IRS. Accordingly, we deny the Attorney General's proposal.

Because Rev. Proc. 2009-39 is a relatively new pronouncement whose application is sufficiently uncertain, the IRS has designated it a high compliance risk "Tier 1" issue (Tr. 8,

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91 There are two components to the Rev. Proc. 2009-39, § 2.08.93 tax accounting change: (1) the current deduction for the repair allowance is increased on a going-forward basis in the year that the change is implemented and subsequent years; and (2) a "catch-up" deduction, referred to as Section 481(a) adjustment, that allows for the cumulative effect of expenditures that had been capitalized in prior years but would be currently deductible under the new accounting method (Exh. AG-DJE, at 18-19).

at 1059).[92] The IRS has not developed guidelines regarding this revenue procedure. If the Company were to seek to change its tax treatment of repair and maintenance costs without further guidance from the IRS, it would do so at the risk of the disallowance of costs and potential IRS penalties. See Rev. Pro. 2009-39. In addition, the Department allows company management considerable discretion in its operational choices. D.P.U. 10-70, at 190, citing 390 Mass. 208, 229. Based on these considerations, the Department finds that the Company's current approach in waiting for further guidance from the IRS is reasonable. D.P.U. 10-70, at 191. Nevertheless, the Department anticipates that at the time the Company files its next rate case, the IRS would have issued additional guidance on this issue for gas distribution companies, allowing for a clear decision on changing the accounting treatment for repairs and maintenance costs. Therefore, we direct NEGC to address this issue in its next rate case, as part of its direct filing.

H. Capitalization of Joint Expenses

1. Introduction

During the test year, the Company booked $1,593,909 in cost allocated from Southern Union (Exhs. NEGC-JMS-3, WP G-12.1; DPU-NEGC-3-13). This total amount allocated to NEGC represents 3.23 percent of the total test year allocable cost of $49,391,368 (RR-AG-6, Att.). The component costs comprising this total amount include costs attributable to (1) SUG

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92 The IRS defines Tier 1 issues as those that "pose the highest compliance risk across multiple LB&I [large business and international] industries and generally include large numbers of taxpayers, significant dollar risk, substantial compliance risk, or are high visibility." http://www.irs.gov/businesses/corporations/article/0,,id=200567,00.html

Air, (2) operation of the New York office, (3) stock options, (4) non-corporate supplemental retirement plan ("SERP"), (5) incentive compensation, and (6) other miscellaneous costs (Exh. NEGC-JMS-3, WP G-12.1; RR-AG-6, Att.). NEGC then removed, from the expense component of its cost of service filing, costs relating to (1) SUG Air, (2) operation of the New York office, (3) stock options, and (4) SERP (Exhs. NEGC-JMS-2, Sch. G-12; NEGC-JMS-3, WPs G-12.1, G-12.2; DPU-NEGC-3-13; Tr. 1, at 93-94). Nonetheless, the Company's allocations from Southern Union continue to include the capitalized portion of Southern Union's 2008 and 2009 costs associated with these excluded or disallowed expenditures (Tr. 1, at 94-96; Tr. 4, at 507; RR-AG-6, Att.). Of this amount, $1,294,659 represents the portion of the test year cost charged to expense (Exh. DPU-NEGC-3-13). The remaining amount of $299,250 is the portion of that total allocated cost that was capitalized (Exhs. AG-1-2(7); DPU-NEGC-3-13; Tr. 1, at 96; Tr. 4, at 489; RR-AG-6, Att.).[93] In addition, the Company indicated that in 2008 it was allocated $1,411,240 representing 2.70 percent of Southern Union allocable cost of $52,350,796 (RR-AG-6, Att.). The Company added that 20.32 percent, or $286,822, of this allocated amount was capitalized in 2008 (RR-AG-6, Att.).

2. Positions of the Parties

The Attorney General acknowledges that the Company has removed test year expenses that had been allocated from Southern Union associated with SUG Air, its New York office, stock options, and SERP (Attorney General Brief at 77-78). The Attorney General, however,

[93] This capitalized amount represents 18.77 percent of the $1,593,909 allocated to NEGC (RR-AG-6, Att.).

claims that the Company has continued to capitalize a portion of these costs on its books since the time of its last rate case and during the test year, including those costs associated with expenses that had been explicitly excluded from cost of service or disallowed by the Department in prior cases (Attorney General Brief at 77-78). By way of example, the Attorney General notes that although the Department disallowed the Southern Union incentive compensation costs in its last rate case, those costs continued to be capitalized on NEGC's books since the last rate case (Attorney General Brief at 78).

More specifically, the Attorney General claims that during 2008, NEGC capitalized $84,531 associated with charges allocated from Southern Union for SUG Air, New York office, stock options, SERP, and incentive compensation (Attorney General Brief at 78, citing RR-AG-6). The Attorney General adds that amounts capitalized during 2009 for these same items totaled $107,551 for a total capitalized costs for 2008 and 2009 of $192,082 ($84,531 + $107,551) (Attorney General Brief at 78, citing RR-AG-6). The Attorney General claims that the Company's witness agreed that the amounts associated with those items that were capitalized during the test year could be removed and that such removal of the capitalized costs would be more consistent with the treatment of the expensed portion of the costs that are allocated from Southern Union (Attorney General Brief at 78, citing Tr. 4, at 491).

The Attorney General, accordingly, recommends that NEGC's rate base should be reduced by $192,082 to remove these inappropriately capitalized costs (Attorney General Brief at 78). The Attorney General further recommends that depreciation expense should be reduced accordingly for the associated impact of this rate base reduction (Attorney General Brief at 78).[94] No other party commented on this issue on brief.

3. Analysis and Findings

In the Company's last rate case, the Department approved the Company's proposal to eliminate $125,979 representing its allocated portion of charges related to two Southern Union corporate jets, New York office, stock options, and SERP because it did not consider these costs to be essential to the provision of distribution service in Massachusetts. D.P.U. 08-35, at 88-89, 96. In addition, the Department denied the Company's proposal to include in its cost of service the amount of $160,642 representing its allocated share of Southern Union incentive compensation. D.P.U. 08-35, at 90, 100.

NEGC removed these cost items from the expense component of its cost of service filing in this case (Exhs. NEGC-JMS-2, Sch. G-12; NEGC-JMS-3, WPs G-12.1, G-12.2; DPU-NEGC-3-13; Tr. 1, at 93-94). Nonetheless, the Company's allocations from Southern Union continue to include the capitalized portion of Southern Union's 2008 and 2009 costs associated with these excluded or disallowed expenditures (Tr. 1, at 94-96; Tr. 4, at 507; RR-AG-6, Att.). More specifically, the Company capitalized in its books $84,531[95] in 2008

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94 The Attorney General also recommends that the Department either direct that such costs not be permitted to be allocated to NEGC's operations from Southern Union or, as an alternative, NEGC be ordered to record such costs in a below-the-line account and not capitalize any portion of the costs on its books (Attorney General Brief at 78).

95 The component breakdown of this cost consists of: $10,933 for SUG Air; $9,862 for New York office; $28,963 for stock options; $2,389 for SERP; and $32,384 for incentive compensation (RR-AG-6, Att.).

and $107,551[96] in 2009, for a total of $192,082, associated with SUG Air, Southern Union's New York office, stock options, SERP, and incentive compensation (RR-AG-6, Att.). The Company acknowledged that removal of these capitalized costs would be consistent with the treatment of the expense portion of the Southern Union allocated costs (Tr. 4, at 491). In addition, if these costs remain capitalized in the Company's books, ratepayers effectively would be funding a portion of costs that had been either excluded by NEGC or denied by the Department (Tr. 1, at 96).

The Attorney General has correctly pointed to an error in the Company's capitalization of these Southern Union allocated costs. NEGC's inclusion of the costs in its rate base calculation demonstrates lax accounting controls considering the ratemaking treatment of these costs established by the Department in the Company's last rate case. See D.P.U. 08-35, at 88-90, 98, 100. Accordingly, the Department will reduce the Company's proposed rate base by $192,082.[97] The appropriate depreciation expense adjustment will be addressed in Section V.L., below.

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96 The component breakdown of this cost consists of: $9,086 for SUG Air; $8,949 for New York office; $46,284 for stock options; $1,277 for SERP; and $41,955 for incentive compensation (RR-AG-6, Att.).

97 Regarding the Attorney General's recommendation on the appropriate financial and bookkeeping approach to these cost items, we find it unnecessary at this time to require below-the-line accounting treatment of these capitalized costs and will leave the matter to the Company's management discretion.

V. OPERATING AND MAINTENANCE EXPENSES

A. Employee Compensation and Benefits

1. Introduction

When determining the reasonableness of a company's compensation expense, the Department reviews the company's overall employee compensation expense to ensure that its employee compensation decisions result in a minimization of unit-labor costs. D.P.U. 10-55, at 234; D.P.U. 96-50 (Phase 1) at 47; Cambridge Electric Light Company, D.P.U. 92-250, at 55 (1993). 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. 92-250, at 55. In addition, the Department requires companies to demonstrate that their total unit-labor cost is minimized in a manner that is supported by their overall business strategies. D.P.U. 92-250, at 55. The individual components of a company's employment compensation package, however, will appropriately be left to the discretion of a company's management. D.P.U. 92-250, at 55-56.

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 that compete for similarly skilled employees. D.P.U. 96-50 (Phase I) at 47; D.P.U. 92-250, at 56; D.P.U. 92-111, at 103; D.P.U. 92-78, at 25-26.

NEGC's employee compensation program encompasses base pay, variable pay, vacation and holiday pay, medical and dental insurance, life and long-term disability insurance, matching contributions to a 401(k) savings plan, and a pension plan and post-retirement benefits other than pension ("Pension/PBOP") (Exhs. NEGC-JMS-1, at 14, 19-20; NEGC-JMS-2, Schs. G-4, G-6; AG-1-42, Att. B at 56-63).[98] The key components of the Company's employee compensation program are discussed in detail below.

2. Payroll Expense

During the test year, NEGC booked $7,512,174 in payroll expense, of which $3,762,774 represented union payroll expense and $3,749,400 represented non-union payroll expense (Exhs. NEGC-JMS-2, Sch. G-4; AG-19-34, Att. at 1-2). Union and non-union wage increases are discussed separately below.

a. Union Wage Increases

i. Introduction

During the test year, NEGC booked $3,762,774 in union payroll expense, including base wages, variable pay, and overtime pay (Exh. AG-19-34, Att. at 1). The Company proposes to increase its union payroll expense by $294,962 (Exh. AG-19-34, Att. at 1). The Company derives the proposed adjustment by multiplying the Company's August 2010 pay rates by a 4.0 percent increase for union employees that is scheduled to take effect in May 2011 under a new union contract that took effect on May 1, 2010 (Exhs. NEGC-JMS-1, at 14; NEGC-JMS-2, Sch. G-4; AG-19-34, Att. at 1). The union contract is for the period

98 Pension/PBOP is recovered outside of base rates and through the Company's LDAF.

May 1, 2010, through May 4, 2013 (Exhs. NEGC-JMSw-1, at 16; AG-1-42, Att. B). The contract provided for union wage increases as follows: (1) five percent effective May 2, 2010; (2) four percent effective May 1, 2011; (3) three and one-half percent effective May 6, 2012 (Exh. AG-1-42, Att. B at 16). In addition, the union contract provided for a staggered increase in the co-pay for health care services (i.e., $5.00 as of May 1, 2010; $10.00 as of January 1, 2011; and $15.00 as of January 1, 2013), and it reduced other employee health-related benefits, as discussed in Section V.A.4., below (Exh. AG-1-42, Att. B at 78-79).

NEGC's pro forma union payroll expense of $4,057,736 excludes $978,367 representing: (1) capitalized payroll; (2) payroll allocated to NEG Appliance and to transportation clearing accounts; and (3) sick pay (Exhs. NEGC-JMS-2, Sch. G-4; AG-19-34, Att. at 1). Allocations to NEG Appliance and transportation clearing accounts, as well as sick pay, are addressed separately in Sections V.N., V.C., and V.A.4., below.

ii. Positions of the Parties

(A) Attorney General

The Attorney General maintains that NEGC's May 2010 union contract provided for "unparalleled increases" in union wages of five percent during 2010, four percent in 2011, and three and one-half percent in 2012, which she maintains is two and three times the current rate of inflation (Attorney General Reply Brief at 19, citing Exh. AG-1-42, Att. B at 16). While the Attorney General acknowledges that the Company's proposal to include these wage increases in its cost of service is consistent with Department precedent, she maintains that given the stagnant economy and high unemployment rate in the Fall River area, these increases are of concern (Attorney General Reply Brief at 19).

The Attorney General argues that NEGC has sought to justify its large increases by claiming that in negotiating the May 2010 union contract, the union gave up certain employee benefits that will reduce benefit costs (Attorney General Reply Brief at 19, citing RR-AG-26). Thus, the Attorney General proposes that the Department deny the Company's recovery of the proposed increases in union wages, because it would be retaining monies associated with the reduced costs from the newly negotiated lower level of employee benefits (Attorney General Reply Brief at 20 n.6). Alternatively, the Attorney General proposes that, to the extent the Department allows an increase in the union wages under the new union contract, the Department should reduce the Company's proposed cost of service to reflect the reduction in benefits costs associated with the reduced employee benefits (Attorney General Reply Brief at 20).

(B) Company

NEGC claims that it has properly fulfilled all the Department's requirements to allow union payroll adjustments (Company Brief at 15-16, citing D.T.E. 05-27, at 106). The Company maintains that its proposed union increase is appropriate because (1) it is scheduled to take effect before the midpoint of the rate year, (2) it is included in the executed union contract, and (3) the Company's compensation levels fall within the middle range of comparable salaries for the region (Company Brief at 16, citing Exh. NEGC-JMS-1, at 14-15).

The Company maintains that the Department's policy is not to limit payroll increases to the level of inflation, nor has it done so in any of its recent cases (Company Reply Brief at 19). According to NEGC, even with the recent union wage increase, overall compensation remains at the median of comparable companies in the Commonwealth (Company Reply Brief at 20). Moreover, the Company contends that its per-employee base payroll expense is significantly less than that recently approved by the Department for Boston Gas Company and Colonial Gas Company (i.e., 21 percent less than Boston Gas Company and 14 percent less than Colonial Gas Company) (Company Reply Brief at 20, citing RR-DPU-1). NEGC also asserts that it has had a long history of granting annual union wage increases that are comparable to the levels granted in the current union contract, and that these percentage increases would have been expected to remain at that level even without the negotiated changes in benefits (Company Reply Brief at 20).

iii. Analysis and Findings

The Department's standard for union payroll adjustments requires that three conditions be met: (1) the proposed increase must take effect before the midpoint of the first twelve months after the rate increase; (2) the proposed increase must be known and measurable (i.e., based on signed contracts between the union and the company);[99] and (3) the proposed increase

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99 A "known" change means that the adjustment must have actually taken place, or that the change will occur based on the record evidence, while a "measurable" change means that the amount of the required adjustment must be quantifiable on the record evidence. D.T.E. 98-51, at 62. Proposed adjustments based on projections or estimates are not allowed. D.T.E. 98-51, at 62, citing D.P.U. 92-210, at 83; Dedham Water Company, D.P.U. 849, at 32-34 (1982).

must be reasonable. D.P.U. 96-50 (Phase I) at 43; D.P.U. 95-40, at 20; D.P.U. 92-250, at 35; Western Massachusetts Electric Company, D.P.U. 86-280-A at 73-74 (1987).

The Company's proposed union payroll adjustments appropriately include only those increases that have been granted or will be granted before the midpoint of the first twelve months after the Department's Order in this proceeding, i.e., October 1, 2011 (Exhs. NEGC-JMS-1, at 14; NEGC-JMS-3, WP G-4.4, at 1-4; DPU-NEGC-1-25). Further, because the union payroll increases are based on signed collective bargaining agreements, the Department finds that the proposed increases are known and measurable (Exh. AG-1-42, Att. B).

The Attorney General criticizes the Company for the percentage increase granted under the May 2010 union contract (Attorney General Brief at 19). The Department is aware of the financial situation in the Commonwealth, including conditions in the Company's service territory. Nonetheless, NEGC has a public service obligation to provide safe and reliable service, and to meet that obligation it must offer compensation structures that attract and retain qualified employees. NEGC participates in various annual salary surveys and uses this data to assess the competitiveness of its own salary levels (Exh. NEGC-JMS-1, at 15). The Company provided survey results that indicate that the hourly rates paid to the Company's union employees are comparable to the rates paid to similarly skilled employees by other gas utilities in the Northeastern United States (Exhs. NEGC-JMS-1, at 14-15; Tr. 1, at 64-65; RR-DPU-1, Atts. A, B). These figures also demonstrate that NEGC's union labor costs are comparable to these gas utilities (RR-DPU-1, Att. B).

Because the Company has met the three conditions required by the Department in allowing payroll adjustments, we reject the Attorney General's proposal to deny the proposed increases.[100] Thus, the proposed adjustment is allowed. Accordingly, the Department will increase the test year cost of service by $294,962.

b. Non-Union Wage Increases

i. Introduction

During the test year, NEGC booked $3,749,400 in non-union payroll expense (Exhs. NEGC-JMS-1, at 14; NEGC-JMS-2, Sch. G-4; AG-19-34, Att. at 2). The Company proposes to increase its non-union payroll expense by $18,171 (Exh. AG-19-34, Att. at 2). The Company derives the proposed adjustment by first multiplying the Company's August 2010 pay rates by a 3.0 percent increase scheduled to take effect in April 2011, producing a revised non-union payroll increase of $116,498 (Exhs. NEGC-JMS-1, at 14; NEGC-JMS-2, Sch. G-4; AG-19-34, Att. at 2; DPU-NEGC-1-23; DPU-NEGC-1-26, Att.).[101] The Company then reduced this amount by $38,227 in non-union payroll expense recovered through NEGC's conservation charge and by $60,100 in salaries allocated to NEG Appliance, resulting in a pro forma non-union payroll expense adjustment of $18,171 (Exhs. NEGC-JMS-1, at 14; NEGC-JMS-2, Sch. G-4; AG-19-34, Att. at 2). NEGC's pro forma non-union payroll expense excludes $649,294 representing: (1) capitalized payroll;

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100 We address the Attorney General's alternative proposal to reduce the allowed health and other employee benefit costs in Section V.A.4. (see Attorney Reply Brief at 20).

101 NEGC initially showed a 3.3 percent wage increase for non-union employees in 2011 (Exh. NEGC-JMS-1, at 15). The Company later clarified that it is proposing a 3.0 percent increase for 2011 (Exh. DPU-NEGC-1-26).

(2) payroll allocated to NEG Appliance; and (3) sick pay (Exhs. NEGC-JMS-2, Sch. G-4; AG-19-34, Att. at 2).

The Company's proposed payroll expense also includes costs related to two positions labeled as vacancies in the test year (Exh. NEGC-JMS-1, at 14). The first position ("Vacancy 1") represents the costs of a records technician hired in 2010 (Exhs. NEGC-JMS-1, at 14; AG-9-20; AG-9-20 Supp.; AG-9-20 2nd Supp.).[102] The proposed expenses related to Vacancy 1 consist of $46,195 in wages and overtime, plus $1,940 in incentive compensation, $3,923 in payroll taxes, and $1,444 in 401(k) matching expense (Exh. NEGC-JMS-3, WP G-4.4, at 1, 3). The second position ("Vacancy 2") represents the costs of an administrative assistant intended to support the activities of management located at the Company's Charles Street LNG facility, particularly those functions related to NEGC's distribution integrity management plan (Exhs. NEGC-JMS-1, at 14; DPU-NEGC-1-24). The proposed expenses related to Vacancy 2 consist of $39,505 in wages and overtime expense, along with $3,263 in payroll taxes and $1,185 in 401(k) matching expense (Exh. NEGC-JMS-3, WP G-4.4, at 2, 4). As of the close of the evidentiary record, Vacancy 2 remained unfilled (see Exh. DPU-NEGC-1-24).

102 NEGC initially stated that this employee was hired in June 2010, but later clarified that the actual hiring date was in December 2010 (Exhs. NEGC-JMS-1, at 14; AG-9-20 Supp.; AG-9-20 2nd Supp.).

ii. Positions of the Parties

(A) Attorney General

The Attorney General argues that all costs (i.e., payroll, incentive compensation, payroll taxes, and 401K matches) related to Vacancy 1 and Vacancy 2 should be removed from the Company's cost of service (Attorney General Reply Brief at 17, citing Exh. NEGC-JMS-3, WP G-4.4, at 1-4). According to the Attorney General, NEGC has provided no support for the inclusion of these "non-employees" in its cost of service (Attorney General Reply Brief at 18). The Attorney General maintains that while the Company may have an intention to fill these positions, NEGC has failed to provide satisfactory evidence to justify inclusion of these expenses as known and measurable changes to its test year cost of service (Attorney General Reply Brief at 17-18). Moreover, the Attorney General maintains that vacancies resulting from employee turnover is a routine event in any large organization, and that the Company should not be permitted to recover costs that are not being incurred (Attorney General Reply Brief at 18).

(B) Company

The Company maintains that its proposed non-union payroll adjustments are consistent with Department precedent (Company Brief at 16-17, citing D.T.E. 05-27, at 107; D.P.U. 92-210, at 35-36; D.P.U. 92-111, at 102; Boston Edison Company, D.P.U. 85-266-A/271-A at 107 (1986)). Specifically, NEGC contends that: (1) management has committed to granting rate increases to non-union employees in 2011; (2) there is a historical correlation between union and non-union pay increases; (3) the compensation levels typically fall within the middle range of comparable industry salaries; and (4) the increase will become effective no later than six months after the date of the Department's Order in this proceeding (Company Brief at 17, citing Exh. NEGC-JMS-1, at 14-15).

NEGC argues that the costs related to Vacancy 1 and Vacancy 2 are being incurred by the Company, and that the costs are both reasonable and prudent (Company Reply Brief at 8). According to the Company, while the Attorney General's observations about employee turnover may be accurate for larger companies, her argument does not apply to small, leanly staffed companies, such as NEGC, that rely extensively on the use of temporary employees who are later hired directly (Company Reply Brief at 10, citing Tr. 3, at 414, 416).

The Company claims that Vacancy 1 was a position in the Company's accounting department held by a full-time employee at the end of the test year, but who subsequently left during 2010 (Company Reply Brief at 8, citing Exhs. AG-9-20 Supp., AG-9-20 2nd Supp.). Upon that employee's departure, the Company maintains it hired a contract employee to fill that position, and subsequently hired that employee on a full-time basis in December 2010 (Company Reply Brief at 8, citing Exhs. NEGC-JMS-3, WP G-4.9; AG-9-20 Supp.; AG-9-20 2nd Supp.). The Company claims that this process is similar to the way NEGC has hired a number of full-time employees (Company Reply Brief at 9). The Company notes that it has removed the cost of this employee from the contract labor account and placed it in the Company's pro forma payroll expense account (Company Reply Brief at 9-10). NEGC points out that, if the Department were to remove the payroll expense for this employee, a corresponding increase in contract labor expense would be warranted (Company Reply Brief at 9).

The Company claims that Vacancy 2 is a new position relating to a management support role for the Charles Street LNG Plant facility (Company Reply Brief at 9, citing Exh. DPU-NEGC-1-24). The Company argues that this position is of critical importance, as management at this facility is faced with a significant workload to comply with federal and state regulations, and is without any clerical assistance at this time (Company Reply Brief at 9, citing DPU-NEGC-1-24).

iii. Analysis and Findings

To recognize an adjustment for an increase in non-union wages that takes place prior to the issuance of an Order, the Company must demonstrate that such increases are known and measurable and also reasonable. See D.P.U. 08-35, at 81-82, 87; D.P.U. 92-250, at 35; Fitchburg Gas and Electric Light Company, D.P.U. 1270/1414, at 14 (1983). To recognize an adjustment for an increase in non-union wages that may occur post-Order, a company must demonstrate that: (1) there is an express commitment by management to grant the increase; (2) there is an historical correlation between union and non-union raises; and (3) the non-union increase is reasonable. D.P.U. 96-50 (Phase I) at 42; D.P.U. 95-40, at 21; D.P.U. 1270/1414, at 14. In addition, only non-union salary increases that are scheduled to take effective before the midpoint of the first twelve months after the rate increase may be included in rates. D.P.U. 85-266-A/271-A at 107.

Here, the Company has provided sufficient evidence to demonstrate that management has expressly committed to granting a 3.0 percent wage increase for non-union wages effective on or before April 1, 2011 (Exh. DPU-NEGC-1-26, Att.). In addition, the Company demonstrated an historical correlation between union and non-union raises (Exh. NEGC-JMS-1, at 15). Specifically, between 2003 and 2010, annual union wage increases were between 3.0 and 5.0 percent and non-union increases were between 2.0 and 3.8 percent (Exh. NEGC-JMS-1, at 15). Therefore, the Department finds that a sufficient correlation exists between union and non-union wage increases. See Fitchburg Gas and Electric Light Company, D.P.U. 07-71, at 76 (2008); D.P.U. 87-59-A at 18.

We must also determine whether the Company's proposed increase is known and measurable. NEGC seeks to recover costs related to two employee vacancies. In the case of Vacancy 1, this position was not vacant in the test year; however, the employee left the Company in 2010 (Exhs. AG-9-20, AG-9-20 Supp., AG-9-20 2nd Supp.). The Company then hired a temporary employee to fill the position, and eventually hired the temporary employee on a permanent basis in December 2010 (Exhs. AG-9-20, AG-9-20 Supp., AG-9-20 2nd Supp.). Consequently, Vacancy 1 had been filled during and after the test year, and the December 2010 hiring replaced the departed employee with a new employee who had been previously serving as a contract employee. In this instance, the Department finds that this process resulted in no net change in the number of Company employees as of the end of the test year and that the costs are known and measurable. Accordingly, the Department will include the costs associated with Vacancy 1 in the Company's cost of service.

Turning to the issue of Vacancy 2, this position was unfilled as of the end of the test year (Exhs. NEGC-JMS-1, at 14; DPU-NEGC-1-24). Although the Department does not dispute the Company's claim as to the need for this new position, the record shows that position remained unfilled as of the close of the evidentiary record (see Exh. DPU-NEGC-1-24). As such, the Department finds that the proposed addition of this position is neither known nor measurable. Accordingly, the Department will exclude the associated costs of Vacancy 2 from the Company's cost of service.

To demonstrate the reasonableness of the non-union wage increase, NEGC regularly participates in various annual salary surveys by the American Gas Association and Mercer LLC and uses the resulting data to assess the competitiveness of its salary levels (Exh. NEGC-JMS-1, at 15; RR-DPU-29, Atts. A, B). The Company has demonstrated that, including the increase for 2010, its non-union compensation levels are comparable to the compensation levels of similarly skilled employees for the natural gas distribution industry in the Northeast (RR-DPU-29, Atts. A, B). The Department finds that NEGC's review of industry compensation data is sufficient to confirm the reasonableness of the Company's salary levels. See D.P.U. 10-55, at 245; D.P.U. 05-27, at 109; D.T.E. 02-24/25, at 94. Further, the Company's proposed non-union payroll adjustments appropriately include only those increases that have been granted or will be granted before the midpoint of the first twelve months after the Department's Order in this proceeding (Exhs. NEGC-JMS-1, at 14; DPU-NEGC-1-23).

Based on the above, and with the exception of Vacancy 2, we find that NEGC has demonstrated that (1) management has expressly committed to granting the wage increase, (2) there is an historical correlation between union and non-union payroll increases, (3) the increases are known and measurable, (4) the increase will take place no later than six months after issuance of this Order, and (5) the increase is reasonable. Consistent with our analysis, the Department will reduce the Company's proposed cost of service by $39,505, representing wages associated with Vacancy 2 (Exh. NEGC JMS-3, WP G-4.4, at 2). In addition, the Department will reduce the Company's proposed cost of service by $4,808, representing $3,263 in payroll taxes and $1,185 in 401(k) matching expense associated with that position (Exh. NEGC JMS-3, WP G-4.4, at 4).

3. Incentive Compensation

a. Introduction

The Department has traditionally allowed incentive compensation expenses to be included in utilities' cost of service so long as they are (1) reasonably designed to encourage good employee performance, and (2) reasonable in amount. 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.T.E. 03-40, at 124; D.P.U. 93-60, at 99. As a rule, if a company's employee performance standards are based on job performance of the individual employee, the incentive plan is deemed to reasonably encourage good employee performance. D.T.E. 02-24/25, at 101-102.

To the extent that the incentive compensation is tied only to financial performance, the benefit to ratepayers is unclear. D.P.U. 89-194/195, at 34.

b. Southern Union Corporate Allocation

i. Introduction

During the test year, the Company booked $154,865,[103] representing NEGC's allocated share of $6,924,725 in incentive compensation expense paid to (1) Southern Union's corporate employees under an annual incentive plan, and (2) Southern Union's two highest-level employees under an amended bonus plan (Exh. AG-3-11; see also Exh. AG-1-36, Att. B; Tr. 8, at 976).[104] Under Southern Union's annual incentive plan, there are separate annual financial performance thresholds for eligible corporate employees, as well as a pool of funds available to pay incentive compensation (Exhs. NEGC-REB-JMS-2(A); AG-1-2(6) at 35). The financial performance measure is a Southern Union earnings-per-share ("EPS") metric, with threshold and target levels set (Exhs. NEGC-REB-JMS-2(A); AG-1-2(6) at 35). Incentives are funded such that if the threshold EPS is not met, no incentive compensation is paid, and if 90 percent of the EPS target is met, 50 percent of the authorized incentive payment pool is available for incentive compensation payments (Exh. AG-1-2(6) at 35). Results in excess of

[103] While the allocated share of $154,865 is not explicitly shown on the Company's schedules, NEGC stated that it had included this amount in its proposed cost of service (Tr. 8, at 976).

[104] Southern Union paid additional bonuses to its highest level executives outside of the annual incentive plan and the amended bonus plan; NEGC is not proposing to recover its allocated portion of these additional bonuses in this proceeding (Exh. AG-10-10).

the target EPS trigger additional pool funding on an incremental basis up to a maximum funding of 120 percent of the authorized pool level (Exh. AG-1-2(6) at 35).

Under Southern Union's amended bonus plan, bonus payments are paid to Southern Union's two highest-level executives based on the achievement of a consolidated net income goal (Exh. AG-1-2(6) at 36). The board of directors' compensation committee, which determines the ultimate bonuses, is permitted to consider additional factors and goals related to Southern Union's strategic, operational, and financial performance in determining whether to award a bonus or reduce an otherwise payable bonus award (Exh. AG-1-2(6) at 36).

ii. Positions of the Parties

(A) Attorney General

The Attorney General argues that the Department should reject the full amount of incentive compensation costs allocated from Southern Union (Attorney General Brief at 69, 75; Attorney General Reply Brief at 14-15).[105] The Attorney General notes that the Department previously found that NEGC failed to demonstrate that Southern Union's annual incentive and amended bonus plans were reasonably designed to encourage good employee performance and would result in benefits to ratepayers (Attorney General Brief at 69, 71, citing D.P.U. 08-35, at 97-100; Attorney General Reply Brief at 15). The Attorney General contends that the Company has not presented anything in the present case to demonstrate that the nature of the

[105] The Attorney General notes that the rejected incentive compensation amount would be either $154,865 or $147,562, based on whether the Department accepts her recommended revisions to the joint and common costs allocation (Attorney General Brief at 71). This is discussed in Section V.G., below.

incentive compensation has changed from the plan rejected by the Department in D.P.U. 08-35 (Attorney General Brief at 69, 71-72; Attorney General Reply Brief at 16).

The Attorney General also maintains that the Southern Union plans are excessive and unreasonable in amount (Attorney General Brief at 73, citing Exh. AG-DR at 23). She asserts that the base salaries for Southern Union's four top executives total $2,959,616 and that Southern Union pays $5,570,000 in incentive compensation to these officers (Attorney General Brief at 73, citing Exh. AG-DR at 23). The Attorney General argues that given the level of base salary for these executives, it is not reasonable to allocate a portion of the $5,570,000 of incentive compensation to NEGC ratepayers (Attorney General Brief at 73). The Attorney General also notes that the Department, in a recent rate case proceeding, reiterated its policy regarding incentive compensation and determined that another company's plan was reasonable, in part, because that company did not seek recovery of incentive compensation for its most senior employees (Attorney General Brief at 72-73, citing D.P.U. 10-55, at 253). The Attorney General argues that, in contrast, the incentive compensation expense for the four top officers of Southern Union makes up the majority of the Southern Union incentive compensation costs that the Company is seeking to recover from NEGC ratepayers in this case (Attorney General Brief at 74).

In addition, the Attorney General argues that for both the amended bonus plan and the annual incentive plan, the Company has not demonstrated (1) that there are any benefits to NEGC ratepayers, or (2) that the employees' performance was tied to meeting safety, reliability, or customer satisfaction goals (Attorney General Brief at 74, citing

Exh. NEGC-REB-JMS-2 & Atts. A, B). The Attorney General asserts that, instead, it appears that Southern Union's incentive plans are based almost entirely on earnings goals and EPS performance (Attorney General Brief at 74, citing Exh. AG-1-2(6)). The Attorney General further states that the listed goals for 2010 are more a description of "normal job functions" than any additional good performance incentives (Attorney General Brief at 75).

(B) Company

NEGC asserts that, contrary to the Attorney General's contentions, the record evidence demonstrates that incentive compensation for Southern Union's corporate management was reasonable (Company Brief at 37, citing Exh. AG-1-2(6)). The Company also asserts that it provided ample evidence to demonstrate that the individual award determination for both individual performance and corporate measures must be achieved before any incentive compensation will be paid (Company Brief at 37, citing Exh. NEGC-REB-JMS-2, Att. A; Tr. 8, at 1075). The Company further asserts that it is not requesting the total amount of incentive compensation paid to executives and that it has limited the corporate incentive compensation to test year levels (Company Reply Brief at 22, citing Exh. AG-10-10).

iii. Analysis and Findings

The Department must first determine whether Southern Union's annual incentive plan and amended bonus plan are reasonable in design. In D.P.U. 08-35, the Department determined that NEGC had provided general information regarding the design of its corporate incentive compensation programs, but had not provided the specific performance goals that each employee who participated in the executive compensation program was required to meet.

D.P.U. 08-35, at 98. We also expressed concern regarding the benefit of incentive compensation plans based solely on a company's financial performance and determined that Southern Union's annual incentive plan relied on the EPS metric, which the Company stated was intended to align employee and shareholder interests. D.P.U. 08-35, at 98-99. Finally, we noted that Southern Union's corporate incentive compensation plans did not include operational or customer service metrics as measures of corporate employee performance. D.P.U. 08-35, at 99. Thus, based on the lack of specificity along with the failure to use appropriate metrics, the Department determined that NEGC did not demonstrate that Southern Union's corporate incentive compensation plans were reasonably designed to encourage good employee performance or result in benefits to NEGC's ratepayers. D.P.U. 08-35, at 99. As such, we excluded NEGC's allocated share of payments made under Southern Union's annual incentive plan and amended bonus plan from NEGC's cost of service. D.P.U. 08-35, at 99-100.

Given the Department's findings in D.P.U. 08-35, the Company should have been aware of the types of incentive compensation plans that the Department would find reasonable. Nonetheless, Southern Union's annual incentive plan and amended bonus plan as outlined in this proceeding are virtually identical to those rejected by the Department in D.P.U. 08-35 (Exh. AG-1-2(6) at 35-36; Tr. 8, 976-977). In fact, the Company affirmed that Southern Union's incentive compensation plans had not been altered since NEGC's last rate case (Tr. 8, at 976-977). In addition, the annual incentive plan continues to be based on an EPS metric, while the amended bonus plan continues to be based on consolidated net income (Exh. AG-1-2(6) at 35-36).

The annual incentive plan states that there are operational metrics for certain business unit employees (Exh. AG-1-2(6) at 35). NEGC also provided an outline of certain operational goals that should be met by corporate employees in 2010 (Exh. NEGC-REB-JMS-2(B)).[106] The Company has not, however, delineated the percentage of Southern Union corporate employees that these operational metrics apply to, nor do the bulk of the outlined goals appear to provide any specific benefit to NEGC's ratepayers (Exhs. AG-1-2(6) at 35-36; NEGC-REB-JMS-2(B)).[107]

NEGC attempted to justify its lack of customer service metrics for Southern Union employees by explaining that NEGC employees work closer to ratepayers on issues directly relating to customer activities and operational efficiencies, while corporate employees are responsible for the business as a whole and provide support services for the entire corporation, as opposed to a single operating unit (Tr. 8, at 1079-1080). Without appropriate customer service and operational metrics, the Company has failed to demonstrate any benefit the corporate employees provide to Massachusetts ratepayers.

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[106] The Company did not provide an outline of the operational and customer service metrics that were in place during the test year. In addition, the fact that NEGC outlined the operational goals for 2010 in its rebuttal testimony rather than in its direct case does not suggest a proactive approach to addressing the concerns outlined by the Department in D.P.U. 08-35.

[107] The operational goals include items such as: (1) provide external auditors fully supported and complete 10-Q/K work papers; (2) timely complete assigned federal and state tax returns; and (3) complete 2010 salary surveys (Exh. NEGC-REB-JMS-2(B)).

Based on the above, we find that the Company has again failed to demonstrate that Southern Union's annual incentive plan and amended bonus plan are reasonably designed to encourage good employee performance and will result in benefits to NEGC's ratepayers. We need not reach the issue of whether any payments made under the Southern Union incentive compensation plans are reasonable in amount. Thus, we will exclude NEGC's allocated share of payments made under Southern Union's annual incentive plan and amended bonus plan of $154,865 from the Company's cost of service.

c. NEGC Employees

i. Introduction

During the test year, NEGC incurred $75,440 in incentive compensation expense for direct Company employees (Exh. NEGC-JMS-3, WP G-6.5, at 1; see also Exh. AG 1-35, Att. A at 3). The Company proposes to increase its test year expense by $212,492, for a total adjusted incentive compensation of $287,932 (see Exh. NEGC-JMS-2, Sch. G-6; Tr. 3, at 427-428).

The performance measures for NEGC employees include both corporate EPS and business unit[108] earnings-before-interest-and-taxes ("EBIT") components, as well as (1) a capital component based on capital cost savings, (2) a customer service component based on

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[108] Southern Union has organized itself into three business units: (1) transportation and storage, conducted through PEPL and its equity interest in Citrus; (2) gathering and processing, conducted through Southern Union Gas Services; and (3) distribution, conducted through Southern Union's NEGC and Missouri Gas Energy operating divisions (Exh. AG-1-2(3) at 6). Other minor operations have been combined for reporting purposes (Exh. AG-1-2(3) at 6).

telephone answering response time, and (3) an operational efficiency component based on the installation of automated meter reading equipment (Exh. DPU-NEGC-1-27, Att. A at 1, 3; Tr. 4, at 539). The corporate EPS and business unit EBIT goals are weighted by employee category, such that the corporate EPS goal is assigned a greater weight for higher-level employees (Exh. DPU-NEGC-1-27, Att. A at 1, 3; Tr. 4, at 542-544). Provided that the threshold EPS and EBIT levels are achieved, the bonus pool is funded so that eligible employees are entitled to 50 percent of the total bonus pool (Exh. DPU-NEGC-1-27, Att. A at 1, 3). If, however, the customer service and operational efficiency goals are not met, no incentive compensation is paid even if the thresholds are achieved (Exhs. DPU-NEGC-1-27, Att. A at 1, 3; DPU-NEGC-1-27 Supp. at 1-2). Similarly, if the employee's performance fails to meet expectations, he or she is not eligible for incentive compensation (Exhs. DPU-NEGC-1-27, Att. A at 3; DPU-NEGC-1-27 Supp. at 1-2; Tr. 4, at 546). If the target EPS and EBIT levels are achieved, eligible employees are entitled to 100 percent of the total bonus pool funding, provided that customer service and operational efficiency goals are met (Exh. DPU-NEGC-1-27, Att. A at 1, 3). If the target EPS and EBIT levels are exceeded, additional bonus pool funding is provided so that eligible employees may receive additional incentive payments up to a maximum of 120 percent of the original bonus pool funding (Exh. DPU-NEGC-1-27, Att. A at 1, 3).

ii. Positions of the Parties

(A) Attorney General

The Attorney General argues that the balance of the $352,763 in incentive compensation expense applicable to NEGC direct employees should be disallowed because it does not meet the Department's criteria for inclusion in rates (Attorney General Brief at 77).[109] The Attorney General contends that the Company is proposing to more than double the actual test year amount of incentive compensation incurred (Attorney General Brief at 75, citing Exh. NEGC-JMS-2, Sch. G-6; Tr. 3, at 427). She also notes that the requested incentive compensation cost is more than four and one-half times higher than the 2008 level and more than five times higher than the 2007 level (Attorney General Brief at 75, citing Exh. AG-1-35, Att. A; Tr. 3, at 428-430; Attorney General Reply Brief at 17). The Attorney General argues that given the significant increases in incentive compensation, the Company has failed to demonstrate that the amount requested is reasonable (Attorney General Brief at 77). She also argues that the plan is heavily weighted to earning goals and to encouraging reductions in capital spending and, thus, is not tied to employees meeting safety, reliability, or customer satisfaction goals (Attorney General Brief at 77). Finally, the Attorney General contends that the Company has assumed that it will receive a rate increase, as a result of this proceeding, large enough to meet its earnings targets (Attorney General Brief at 76, citing Tr. 3,

109 The $352,763 referenced by the Attorney General is the Company's adjusted incentive compensation before any costs are removed (e.g., NEG Appliance) (see Exh. NEGC-JMS-2, Sch. G-6 (Rev.)).

at 419-420). She reasons that, as a result, a rate increase is needed both to trigger and to fund the incentive compensation plan (Attorney General Brief at 76).

(B) Company

The Company argues that it has taken great efforts to provide detailed documentation outlining each eligible NEGC employee's performance and the sufficiency of his or her efforts to strive to provide customers a safe, reliable, and efficient gas operation (Company Brief at 38, citing RR-AG-5). NEGC also asserts that its employees received substantially less for total compensation, including incentive compensation, than the amounts recently approved as reasonable by the Department for National Grid in D.P.U. 10-55 (Company Reply Brief at 22, citing RR-DPU-1). In addition, the Company contends that its proposal to increase incentive compensation over the test year amount is necessary because incentive compensation is, to some extent, tied to NEGC's financial performance (Company Reply Brief at 22). NEGC accepts the Attorney General's position that a rate increase will translate into an increase in incentive compensation because the Company should be in better financial condition (Company Reply Brief at 22-23, citing Tr. 3, at 419).

iii. Analysis and Findings

As a threshold matter, we must determine whether the annual incentive plan as applicable to NEGC employees is reasonable in design. The plan's performance measures include both financial goals and personal goals (Exh. DPU-NEGC-1-27, Att. A at 1, 3). In addition, the record shows that the individual performance goals are tied to safety, reliability, and customer satisfaction and, therefore, are directly aligned with the interests of ratepayers

(Exh. DPU-NEGC-1-27, Att. A at 1, 3; RR-AG-5, Att.). For example, many of the goals listed include quantifiable metrics such as (1) meeting service quality standards, (2) reducing dispatch overtime, (3) maintaining appropriate leak response times, (4) reducing storage costs, and (5) reducing errors in cash balancing (RR-AG-5, Att. at 1, 16, 56, 107). These individual performance goals appear to be designed to encourage good employee performance. Thus, we find that the incentive compensation plan as applicable to NEGC employees is reasonably designed to encourage good employee performance and provide benefit to ratepayers. In determining whether the incentive compensation plan expense is reasonable, we note that the Company has conducted an analysis of base salaries and target total compensation compared to the market (Exh. RR-DPU-1, Att.).

The Attorney General appears to suggest that NEGC's incentive compensation structure provides a perverse incentive for the Company to increase rates so that earnings targets may be achieved and thus maximize incentive payments to employees (Attorney General Brief at 76). While it is evident that the Company requires rate levels that are sufficient to support its earnings targets, which affects the level of funds available for incentive compensation, the truism has little, if any, relevance here. The Department's ratesetting process is intended to develop a revenue level that, with efficient management, provides companies with the opportunity to earn a reasonable return. The method and manner by which the Company uses those earnings to design its incentive compensation structure is more appropriately left to the discretion of NEGCs management.

d. Conclusion

As outlined above, we find that the Company has failed to demonstrate that Southern Union's annual incentive plan and amended bonus plan are reasonably designed to encourage good employee performance or will benefit NEGC's ratepayers. Thus, we will exclude NEGC's allocated share of payments made under Southern Union's annual incentive plan and amended bonus plan from the Company's cost of service. Accordingly, the Company's proposed cost of service will be reduced by $154,865.

With respect to the direct Company employee compensation plan, we find that the Company has demonstrated that its incentive compensation plan encourages good employee performance and results in benefits to ratepayers. Therefore, the Department will permit the inclusion of NEGC's proposed incentive compensation expense for direct Company employees of $287,932 in its cost of service.

4. Employee Benefits

a. Introduction

During the test year, the Company booked $1,858,487 in various employee benefits expense, including: (1) matching contributions to a 401(k) retirement savings account;[110] (2) medical, dental, life, and disability insurance expenses; (3) employee assistance program

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110 For union members, NEGC matches an employee's contribution to its 401(k) retirement savings account up to four percent of that employee's eligible annual earnings (Exh. AG-1-42, Att. B at 62). For certain union employees (e.g., recent hires), the union contract limits the matching contribution to two percent of the eligible annual earnings (Exh. AG-1-42, Att. B at 62). For non-union employees, NEGC matches an employee's contributions to its 401(k) retirement savings account up to four percent of that employee's eligible annual earnings (Exh. AG-1-50, Att. A at 1).

expense; (4) sick pay; and (5) other miscellaneous benefits such as deferred compensation and stock options (see Exhs. NEGC-JMS-3, WP G-6.5, at 1-2; AG-1-50, Atts. A, C).[111] The Company proposes to decrease its test year cost of service for employee benefits costs other than pension/PBOP by $50,741 based on proposed payroll levels and the most recent invoices and historical claim payments (Exhs. NEGC-JMS-1, at 19-20; NEGC-JMS-2, Sch. G-6 (Rev.)).[112]

To derive its proposed adjustment, NEGC first calculated a revised 401(k) expense, as well as revised expense levels for: (1) medical, dental, vision, life, and disability insurance expense; (2) employee assistance; and (3) sick pay (collectively "employee health benefits"); all based on the Company's proposed payroll levels and the most recent invoices and historical claim payments, which include higher employee copays that are provided under the union contract effective May 2011 (Exhs. NEGC-JMS-1, at 19-20; NEGC-JMS-2, Sch. G-6 (Rev.)).[113] Based on this updated information, the Company reports a revised 401(k) expense of $363,690 and a revised employee health benefits expense of $1,640,405, which when added to NEGC's test year miscellaneous benefits expense of $122,426, produces a total expense of

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111 Pension/PBOP is recovered separately through the Company's LDAF, and NEGC's incentive compensation is discussed in Section V.A.3., above.

112 As noted in Section V.A.2.a., above, the May 2010 union contract reduced certain employee benefits. The Company excluded from its proposed cost of service a net $20,569 to reflect the removal, in the union contract, of an alternative insurance program (RR-AG-28; see also Exh. NEGC-JMS-3, WP G-6.2).

113 The Company's revenue requirement calculations combine 401(k) expense with incentive compensation expense (Exh. NEGC-JMS-2, Sch. G-6 (Rev.)). The Department addresses incentive compensation in Section V.A.3., above.

$2,126,521 (see Exh. NEGC-JMS-2, Sch. G-6 (Rev.)). The Company then removed $7,094 in 401(k) expenses and $36,872 in employee health benefits expenses, respectively, that were identified to be associated with direct NEG Appliance employees (see Exh. NEGC-JMS-2, Sch. G-6 (Rev.)). This adjustment produced a revised 401(k) expense of $356,596 and a revised combined employee health benefits and miscellaneous benefits expense of $1,725,959 (see Exh. NEGC-JMS-2, Sch. G-6 (Rev.)).

Next, the Company removed $48,586 in 401(k) expense and $226,313 in combined employee health benefits and miscellaneous benefits expense related to (1) NEG Appliance, (2) transportation and work equipment labor, (3) capitalized labor, and (4) labor costs recoverable through the Company's conservation charge (Exh. NEGC-JMS-1, at 20-21; see Exh. NEGC-JMS-2, Sch. G-6 (Rev.)). Based on these adjustments, the Company has proposed to include in cost of service $308,010 in 401(k) expense and $1,499,736 in combined employee health benefits and miscellaneous benefits expense for a total decrease of $50,741 to test year cost of service (see Exh. NEGC-JMS-2, Sch. G-6 (Rev.)).

b. Positions of the Parties

i. Attorney General

The Attorney General asserts that the Company's proposed cost of service fails to take into consideration the savings that NEGC anticipates will result from the increased employee health insurance copays and contributions that had been negotiated in the 2010 union contract (Attorney General Reply Brief at 19, citing Exh. NEGC-JMS-3, WP-G-4.4; RR-AG-26). The Attorney General points out that NEGC's new union contract provides for what she characterizes as "unparalleled" increases in union wages of five percent during 2010, four percent in 2011, and three and one-half percent in 2012, all of which are two and three times the current rate of inflation (Attorney General Reply Brief at 19, citing Exh. AG-1-42, Att. B at 16). The Attorney General contends that, in view of the Fall River area's poor economic conditions with one of the highest unemployment rates in the Commonwealth, the Company is inappropriately attempting to "have it both ways" by seeking to recover these wage levels, while at the same time disregarding the offsetting savings in employee benefits that gave rise to the level of union increases granted in the first place (Attorney General Reply Brief at 19-20, citing RR-AG-26). The Attorney General claims these cost savings are significant, measurable, and recurring, and thus should be included as a reduction to the cost of service (Attorney General Reply Brief at 20, citing RR-AG-26).[114]

ii. Company

NEGC maintains that its proposed health and related employee benefit expenses are appropriate and reasonable (Company Brief at 18). The Company argues that the Attorney General's proposal is flawed for numerous reasons. The Company contends that because its proposed cost of service does not incorporate all of the anticipated increases resulting from the new union contract, such as those contractual salary increases scheduled to take place during 2012, the Attorney General is inconsistent in her demand that all estimated savings be incorporated here (Company Reply Brief at 17-18).

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114 Alternatively, the Attorney General argues that the Department should deny the Company's proposed union wage increases (Attorney General Reply Brief at 20 n.6). The Attorney General's argument is addressed in Section V.A.2.a., above.

NEGC also maintains that even if all of the anticipated savings were included here, the Company's cost of service would still increase because health care costs will continue to grow and, as such, any benefit savings expected to be achieved in the future will simply reduce the rate of future increases in benefit costs, rather than reduce total expenditures (Company Reply Brief at 18, citing Tr. 4, at 548). In addition, the Company contends that not all of the expected savings arising from changes in the union benefits are susceptible to quantification (Company Reply Brief at 19, citing Tr. 4, at 548). NEGC asserts that to the extent it was able to quantify any savings, it included those savings in its proposed cost of service (Company Reply Brief at 19, citing Exh. NEGC-JMS-1, at 18; RR-AG-28; RR-DPU-33 Supp.). Based on the above, NEGC argues that the Attorney General's proposal is inconsistent with Department precedent, which NEGC asserts does not include future projections or estimated cost increases or decreases in the cost of service (Company Reply Brief at 19).

c. Analysis and Findings

In a regulated monopoly environment, such as the one in which LDCs operate, companies compete with other regulated and non-regulated companies to attract and retain employees. Accordingly, regulated monopolies must offer employee compensation packages that are competitive with these other companies. D.P.U. 92-250, at 55.[115] Because regulated monopolies are not subject to the same level of product competition that creates the downward pressure on employee compensation expenses in a competitive market environment, regulators

115 Different components of compensation, e.g., wages and fringe benefits, can be to some extent substitutes for each other, and different combinations of these components may be used to attract and retain employees. D.P.U. 92-250, at 55.

review a company's employee compensation expenses to ensure the reasonableness of such expenses. D.P.U. 92-250, at 55; see also D.T.E. 01-56, at 60; D.P.U. 96-50 (Phase I) at 45-46; North Attleboro Gas Company, D.P.U. 86-86, at 8 (1986).[116] Further, any post-test-year adjustments must be known and measurable. D.T.E. 01-56, at 60; D.P.U. 96-50 (Phase I) at 45-46; D.P.U. 86-86, at 8. With respect to health care costs, companies must demonstrate that they have acted to contain such 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 29-30; Nantucket Electric Company, D.P.U. 91-106/138, at 53 (1991).

NEGC has provided sufficient evidence to demonstrate that its health, 401(k) plan, and other employee benefit expenses are reasonable in amount (see, e.g., Exhs. NEGC-JMS-2, Sch. G-6 (Rev.); NEGC-JMS-3, Sch. G-6.2; Tr. 1, at 68-69; RR-DPU-2, Att.; RR-DPU-33 Supp. Att.). In addition, the Company has shown that its proposed adjustments are known and measurable (see, e.g., Exhs. NEGC-JMS-2, Sch. G-6 (Rev.); NEGC-JMS-3, Sch. G-6.5; DPU-NEGC-3-2). The Department also finds that the Company has taken reasonable and effective cost-control measures regarding its health care costs (see, e.g., Exhs. AG-1-51; AG-1-52; RR-AG-26; RR-AG-27; RR-AG-28; RR-AG-29; RR-AG-30; RR-AG-31; RR-DPU-3; RR-DPU-3 Supp.). For example, the Company has recently reduced its health care plan benefits through its 2010 union contract by increasing copays on health and dental

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116 The Department does not require ratepayers to pay for employee fringe benefits that would be characterized as extravagances. D.P.U. 92-111, at 151-154 (disallowing costs for employees' spouses attending business functions); Fall River Gas Company, D.P.U. 750, at 15 (1981) (disallowing officers' luxury vehicle costs).

plans (RR-DPU-3 Supp.). In addition, NEGC has introduced a cost-sharing methodology that will share the total cost of health care with employees on an 80/20 company-to-employee basis (Exh. AG-1-52; RR-DPU-3 Supp.). Further, NEGC has incorporated a preferred provider arrangement to encourage employees to choose a medical provider that participates in an approved network (Exh. AG-1-52; RR-DPU-3 Supp.). The Company states that having a preferred provider arrangement will ensure that its employees receive quality care, while at the same time ensure that NEGC controls its health care costs by receiving substantial network cost discounts (Exh. AG-1-52). The Company also has a pharmacy program that is designed to encourage a preference for lower-cost alternatives, such as generic drugs and a mail-order option (Exh. AG-1-52; RR-DPU-3 Supp.). The Company has also eliminated an alternative insurance program that allowed employees to receive reimbursement for claims not covered by the Company's primary insurance carrier (Exh. NEGC-JMS-1, at 18-20; RR-AG-28). Finally, the Company provides coverage for preventative services to identify medical conditions early and prevent more serious conditions later (Exh. AG-1-52; RR-DPU-3 Supp.).

The Attorney General contends that the Company's cost of service should be adjusted to reflect those estimated cost savings as a result of the negotiated 2010 union contract (Attorney General Reply Brief at 19). When a significant change has occurred at a utility, the Department has accepted cost of service reductions based on evidence supported by the record. D.P.U. 93-60, at 39-40. In fact, NEGC has included $20,569 in savings resulting from the termination of its former alternative insurance program (Exh. NEGC-JMS-1, at 18-20; RR-DPU-33 Supp.; RR-AG-28). While the Company has derived estimates of additional savings it expects to realize on an annual basis due to health care plan changes, such as higher copays, this information consists of dollar ranges anticipated to result from each change (RR-DPU-3, Att.).[117] Although this type of information may be sufficient to evaluate the merits of various proposals raised during the collective bargaining process, the estimates themselves are insufficient to determine the level of savings, if any, that may be included in NEGC's proposed cost of service. As such, the Department finds that these estimated savings are not known and measurable. Therefore, the Department denies the Attorney General's request to include any expected savings from the Company's changes to the Company health care plan as a reduction to NEGC's cost of service.

Based on the foregoing analysis, the Department finds that NEGC's proposed adjustments to its 401(k), with the exception of Vacancy 2 as outlined in Section V.A.2.b., above, and employee benefits expenses are known and measurable. Therefore, the Department accepts the Company's proposed adjustment. Accordingly, NEGC's proposed cost of service is accepted.

B. Contract Labor/Outside Services

1. Introduction

During the test year, the Company booked a total of $1,282,212 to Account 880, Other Expenses, of which $70,910 represented outside services expense (Exh. AG-3-17, Att. A at 3).

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117 Excluding those categories where saving estimates are reported as being "less than" a particular number, the overall savings estimates range between $114,000 and $138,000 (RR-DPU-3, Att.).

These outside services consisted of $42,330 in contract labor,[118] $9,505 in software license costs, and $19,075 in emergency response plan development costs (see Exhs. NEGC-JMS-2, Sch. G-8 (Rev.); AG-3-17, Att. A at 3; AG-9-20; AG-9-20 Supp.). According to the Company, its contract labor expense relates to the use of temporary employees to fill full-time positions at the Company (Exh. NEGC-JMS-1, at 22). In its initial filing, the Company proposed to reduce its test year outside services expense by $74,010 to reflect positions held by temporary employees that were subsequently filled by permanent full-time employees (Exh. NEGC-JMS-2, Sch. G-8). During the proceedings, however, NEGC identified an additional $38,353 in costs related to a temporary employee who remains with the Company (Exh. AG-9-20 Supp.). Consequently, NEGC has reduced its proposed adjustment to $35,657, and proposes to include in cost of service $40,974 in contract labor expenses booked to Account 880 (Exhs. NEGC-JMS-1, at 22; NEGC-JMS-2, Sch. G-8 (Rev)).

2. Attorney General Proposal

The Attorney General states that the level of outside services booked to Account 880 is significantly higher than during 2008 (Exh. AG-DJE at 12).[119] The Attorney General further states that while NEGC has appropriately removed the cost of temporary employees who have

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[118] During the test year, NEGC booked a total of $76,631 in contract labor, of which $42,330 was booked to Account 880, Other Expenses; while the remaining $34,301 was booked to Account 903, Customer Records and Collection Expense; Account 920, Administration and General Salaries; and Account 921, Office Supplies and Expenses (Exh. NEGC-JMS-2, Sch. G-8 (Rev.)).

[119] During the test year, NEGC booked $70,910 in outside services expense to Account 880, compared with $56 during 2008 (Exh. AG-3-17, Att. at 3). The Company attributed this increase to increased leak repair activity (Exh. AG-3-17).

been replaced by permanent NEGC employees, Account 880 still includes approximately $29,000 in outside services expense, consisting of software licensing costs and costs related to the development of an emergency response plan (Exhs. AG-DJE at 12; AG-9-20). The Attorney General states that based on her review, the software licensing and emergency response plan costs appear to be of a non-recurring nature (Exh. AG-DJE at 12, citing Exh. AG-9-20). Consequently, the Attorney General concludes that unless NEGC is able to demonstrate that these costs are of a recurring nature, a further reduction to Account 880 expenses of $29,000 is warranted (Exh. AG-DJE at 12).

3. Positions of the Parties

a. Attorney General

The Attorney General argues that certain outside service expenses incurred by NEGC in the test year are non-recurring in nature and, as such, should be excluded from cost of service (Attorney General Brief at 60-61, citing Exh. AG-DJE-1, at 12). On brief, the Attorney General acknowledges that while NEGC has established that approximately $9,000 in software licenses expense is recurring, the Company has failed to demonstrate that the emergency response plan development costs of approximately $20,000 are of a recurring nature (Attorney General Brief at 61, citing Exh. AG-9-20 Supp.). Thus, the Attorney General proposes that the Company's test year O&M expense should be reduced by approximately $20,000 (Attorney General Brief at 61).

b. Company

In addressing the outside service expenses, the Company contends that it has appropriately excluded certain costs from its test year because these involved temporary contractors whose positions were subsequently filled by permanent employees (Company Brief at 19, citing Exh. NEGC-JMS-1, at 22). The Company also argues that it has appropriately included the cost of one particular temporary employee in recognition of the fact that it will continue to rely on contract labor in the future (Company Brief at 19, citing Exh. AG-9-20 Supp.). NEGC does not address the Attorney General's argument concerning the Company's emergency response plan development costs.

4. Analysis and Findings

Test year expenses that recur on an annual basis are eligible for full inclusion in cost of service unless the record supports a finding that the level of the expense in the test year is abnormal. D.P.U. 1270/1414, at 33. During the test year, the Company booked $76,631 in contract labor expense (Exhs. NEGC-JMS-2, Sch. G-8 (Rev.); AG-3-17, Att. A at 3). The Company proposes to exclude a net total of $35,657, comprised of: (1) $1,356 in contract labor booked to Account 880; and (2) $34,301 in contract labor costs booked to other accounts (Exh. NEGC-JMS-2, Sch. G-8 (Rev.)). The Department finds that the proposed reduction to contract labor costs represents a known and measurable change to test year cost of service. Pinehills Water Company, D.T.E. 01-42, at 13-14 (2001); Butterworth Water Company, D.P.U. 85-152, at 12-13 (1987). Therefore, the Department accepts the Company's proposed adjustment.

Turning to the remaining $28,580 identified by the Attorney General, $9,505 represents annually recurring computer software licenses (Exh. AG-9-20 Supp.). As these expenses are annually recurring, the Department will include them in the Company's cost of service. D.P.U. 1270/1414, at 33. The remaining $19,075 relates to the Company's emergency response plan. NEGC's discussion of this expense is confined to a passing reference in Exhibit AG-9-20 that did not include any explanation of the cost or give any indication that the cost was recurring in nature. Furthermore, while the Company supplemented this same exhibit with a detailed explanation of its computer software licenses, including invoices, the Company did not take the opportunity to supplement the record on the issue of its emergency response plan (Exh. AG-9-20 Supp.). Commonwealth Electric Company, D.P.U. 89-114/90-331/91-80 (Phase One) at 82 (1991) (Attorney General provided indications that should have made the company aware that it was being challenged to provide documentation of the reasonableness of the charges). Therefore, the Department finds that the Company has failed to demonstrate that its test year emergency response plan preparation costs are recurring in nature. Accordingly, the Department will reduce the Company's proposed cost of service by $19,075.

C. Transportation and Work Equipment Expense

1. Introduction

During the test year, NEGC booked $491,043 to the transportation and work equipment ("TWE") expense clearing account (Exh. NEGC-JMS-2, Sch. G-7). TWE expenses include the costs associated with vehicles and work equipment such as leases, depreciation, fuel, tires, oil changes, and inspections, as well as labor and related benefits (Exh. NEGC-JMS-1, at 21).

The Company formerly leased a number of vehicles from GE Capital Commercial, Inc. ("GE Capital") (Exhs. DPU-NEGC-3-1, Att. A; AG-1-19, Att. A at 1). In November 2008, GE Capital informed NEGC that it was exiting the leasing business, and thus invoking a provision of the lease that required the Company to buy out the remaining leases (Exh. DPU-NEGC-3-1, Att. A; Tr. 1, at 32-33). NEGC purchased the vehicles formerly under lease in April 2009 (Exhs. DPU-NEGC-3-1; DPU-NEGC-7-2; Tr. 1, at 32-33, 43-44).

To calculate an adjusted TWE expense, the Company removed the test year lease costs associated with the purchased vehicles and replaced that amount with the depreciation expense on company-owned vehicles (Exhs. NEGC-JMS-1, at 21-22; NEGC-JMS-2, Sch. G-7).[120] In addition, a portion of the costs associated with field service employees who performed work on behalf of NEG Appliance were removed from the adjusted TWE expense (Exh. NEGC-JMS-1, at 22).

The Company calculated an adjusted TWE expense of $495,114 (Exh. NEGC-JMS-2, Sch. G-7). Comparing the adjusted expense to the test year TWE expense of $491,043 results in an increase to NEGC's test year cost of service of $4,070 (Exh. NEGC-JMS-2, Sch. G-7).

NEGC asserts that because the lease buy-outs were completed in the test year, it appropriately removed the test year lease costs and replaced the costs with depreciation expense (Company Brief at 19). No other party commented on the proposed TWE expense adjustment on brief.

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120 The purchased vehicles have been included in rate base (Exh. AG-1-19, Att. A at 1).

2. Analysis and Findings

The Department typically includes a test year level of expenses in cost of service, and will adjust this level for known and measurable changes to the test year. D.P.U. 87-260, at 75; D.P.U. 1270/1414, at 33. The Department will exclude from cost of service the test year expense associated with leases that have expired, or that will expire in the early part of the first twelve-month period following the issuance of the rate order. D.P.U. 87-260, at 75.

The Department finds that NEGC's treatment of its TWE account is appropriate. GE Capital's decision to exit the leasing business was outside of NEGC's control (Exhs. DPU-NEGC-3-1; DPU-NEGC-7-2; Tr. 1, at 32-33). The Company has further demonstrated that it attempted to enter into replacement lease arrangements but was unsuccessful in obtaining alternative arrangements before the deadline provided by GE Capital (Exh. DPU-NEGC-7-2). As such, the Department accepts NEGC's adjustments to remove test year lease costs and add the associated depreciation expense on the newly-acquired vehicles. The Department has also examined the Company's removal of costs associated with field service employees who performed work on behalf of NEG Appliance. The Department finds that the treatment of such costs is appropriate and that the TWE clearing ratios have been accurately calculated (Exhs. NEGC-JMS-2, Sch. G-7; NEGC-JMS-3, WP G-7.3; DPU-NEGC-2-3). Therefore, the Department will increase the Company's test year cost of service by $4,070.

D. Interest on Customer Deposits

1. Introduction

As of the end of the test year, December 31, 2009, the customer deposit balance for NEGC was $401,983, with an associated interest expense of $7,389 (Exh. NEGC-JMS-2, Sch. G-9 (Rev.)). The Company proposed to reduce the test year O&M associated interest expense of $7,389 by $3,530 for interest on the test-year-end level of customer deposits (Exh. NEGC-JMS-2, Schs. B (Rev.), G-9 (Rev.)). The Company calculated this proposed adjustment in two steps: (1) by multiplying the test year ending balance of customer deposits by the then-current customer deposit interest rate of 0.96 percent;[121] and (2) by subtracting from that amount the test year interest on customer deposits of $7,389, resulting in the proposed adjustment of $3,530 (Exhs. NEGC-JMS-1, at 23; NEGC-JMS-2, Sch. G-9 (Rev.)). The Company states that this adjustment normalizes interest on customer deposits (Exh. NEGC-JMS-1, at 23). No party commented on this matter.

2. Analysis and Findings

The Department's policy is to treat customer deposits as an offset to rate base and to include in cost of service the interest paid on these deposits. D.P.U. 1720, at 90-91; Eastern Edison Company, D.P.U. 1580, at 46-47 (1984); D.P.U. 1350, at 20-21. NEGC has included the customer deposit balance of $401,983 as an offset to rate base (Exh. NEGC-JMS-2, Sch. B (Rev.)). Consistent with this treatment, the Department finds it appropriate to include in the

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[121] This is the interest rate on two-year treasury notes as of December 31, 2009. Federal Reserve Statistical Release H.15, "Selected Interest Rates", http://www.federalreserve.gov/releases/h15/data/Annual/H15_TCMNOM_Y2.txt

costs of service for NEGC the appropriate interest expense associated with these deposits. D.P.U. 906, at 24.

The Department's regulations require utility companies to pay interest on any deposit, represented by cash or cash-equivalent securities that are held for more than six months. 220 C.M.R. § 26.09. The interest rate is equal to the rate paid on two-year U.S. Treasury notes for the preceding twelve months ending December 31st of each year, as published by the Federal Reserve System in the Federal Reserve Statistical Release G.13 (415), "Selected Interest Rates" during the first week of January.[122] 220 C.M.R. § 26.09(2). The interest rate on two-year U.S. Treasury notes for the year ending December 31, 2010, was 0.70 percent. Federal Reserve Statistical Release H.15, "Selected Interest Rates", http://www.federalreserve.gov/releases/h15/data/Annual/H15_TCMNOM_Y2.txt.

The Department finds it appropriate to apply the most currently available applicable U.S. Treasury rate. Therefore, the Department will apply the lower interest rate of 0.70 percent to the test-year-end balance of customer deposits, producing a net interest expense for NEGC of $2,814 (see Exh. NEGC-JMS-2, Sch. B (Rev.)). Accordingly, the Company's proposed cost of service will be reduced by $716.

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122 The Federal Reserve discontinued publishing G.13 (415) as of January 8, 2002; the same information is provided in Federal Reserve Statistical Release H.15, "Selected Interest Rates."

E. Bad Debt Expense

1. Introduction

During the test year, NEGC booked $387,364 to bad debt expense (Exh. NEGC-JMS-2, Sch. G-10). The Company reduced this amount by $208,655 to account for a prior year true-up relating to the historical treatment of gas related bad debts, resulting in a net test year bad debt expense of $178,709 (Exhs. NEGC-JMS-2, Sch. G-10; DPU-NEGC-3-12). The Company recovers bad debt expense associated with (1) distribution service through base rates, and (2) supply through the CGAC[123] (Exhs. NEGC-JMS-1, at 23; DPU-NEGC-1-2).

The Company determined a representative level of bad debt expense to be recovered through base rates by comparing actual distribution-related net write-offs to firm billed distribution related revenue for the three years ending December 31, 2009, and deriving the three-year weighted average of net write-offs as a percentage of billed distribution revenue (Exhs. NEGC-JMS-1, at 23; NEGC-JMS-2, Sch. G-10). The Company then multiplied the three-year weighted average percentage by test year normalized firm sales revenues to obtain a bad debt allowance (Exhs. NEGC-JMS-1, at 23; NEGC-JMS-2, Sch. G-10).

NEGC calculated a distribution-related bad debt ratio of 1.84 percent which, when applied to the total distribution revenues of $28,935,369,[124] results in a proposed bad debt

[123] The bad debt expense associated with supply is recovered dollar-for-dollar through the CGAC.

[124] The $28,935,369 is composed of $19,805,530 in base distribution revenues and $9,129,839 in LDAC revenue (Exh. NEGC-JMS-2, Sch. G-10 (Rev.)).

allowance of $532,411 (Exh. NEGC-JMS-2, Sch. G-10). Subsequently, the Company revised its proposed bad debt ratio to 1.60 percent to address a concern raised by the Attorney General (Exh. NEGC-JMS-2, Sch. G-10 (Rev.)). Applying the 1.60 percent ratio results in a bad debt allowance of $462,966 (Exh. NEGC-JMS-2, Sch. G-10 (Rev.)). The revised bad debt allowance results in a proposed increase to test year cost of service in the amount of $284,256 (Exh. NEGC-JMS-2, Sch. G-10 (Rev.)).

2. Positions of the Parties

a. Attorney General

The Attorney General notes that because the write-offs in June 2007 included a catch-up adjustment relating to a delay in the proper coding of bad debt accounts, the write-offs in that month are substantially higher than any other month in the years 2007 through 2009 (Attorney General Brief at 53, citing Exhs. AG-DJE-1, at 5; AG-3-15). The Attorney General argues that the catch-up adjustment made in June 2007 causes a disparity between the write-offs booked and the revenues recognized in that year (Attorney General Brief at 53). To correct for this disparity, the Attorney General asserts that the Company should calculate its 2007 write-off percentage without the catch-up adjustment, which reduces NEGC's proposed uncollectible expense by $69,000 (Attorney General Brief at 53-54, citing Exh. AG-DJE-1, at 6-7). As a result, the Attorney General proposes that the Company's bad debt allowance of $532,411 be reduced by approximately $69,000 (Attorney General Brief at 54).

b. Company

NEGC asserts that its treatment of uncollectible expense is consistent with the Department precedent (Company Brief at 20). The Company maintains that it adjusted uncollectible expense by first developing an uncollectible expense ratio using a three-year average of historical bad-debt write offs, net of recoveries, divided by total billed revenues (Company Brief at 20, citing Exh. NEGC-JMS-1, at 23). The Company contends it then multiplied total adjusted base and LDAC revenue by this ratio to determine normalized uncollectible expense for base rates (Company Brief at 20, citing Exh. NEGC-JMS-1, at 23). While NEGC did not address the Attorney General's concerns on brief, the Company accepted the Attorney General's adjustment in its revised revenue requirement (see Exh. NEGC-JMS-2, Sch. G-10 (Rev.)).

3. Analysis and Findings

The Department permits companies to include for ratemaking purposes a representative level of bad debt revenues as an expense in cost of service. D.P.U. 09-39, at 164; D.P.U. 96-50 (Phase I) at 70-71; D.P.U. 89-114/90-331/91-80 (Phase One) at 137-140. The Department has found that the use of the most recent three years of available data is appropriate in the calculation of bad debt. D.P.U. 96-50 (Phase I) at 71. When a company is allowed dollar-for-dollar recovery of bad debt expense associated with supply (commodity related), the appropriate method to calculate bad debt related to distribution is to remove all revenues relating to supply from the company's bad debt calculations. See D.P.U. 07-71, at 106-109.

The record shows that the method used by NEGC to calculate its distribution-related bad debt adjustment is consistent with Department precedent (Exhs. NEGC-JMS-1, at 23; NEGC-JMS-2, Sch. G-10). See D.P.U. 07-71, at 106-109; D.P.U. 96-50 (Phase I) at 70-71; D.P.U. 89-114/90-331/91-80 (Phase One) at 137-140. The Attorney General correctly notes that the Company mistakenly included 2006 costs in its 2007 net write-off amount, which resulted in an elevated level of write-offs for the month of June 2007 (Exh. AG-3-15; Tr. 8, at 970). The higher-than-average write-offs for June 2007 relate to accounts that should have been written off in 2006 (Tr. 8, at 970). As noted above, the Company modified its revenue requirement to incorporate the Attorney General's proposed adjustment (Exh. NEGC-JMS-2, Sch. G-10 (Rev.)). Thus, the Department finds that the Company appropriately eliminated the June 2007 write-offs and annualized the write-offs for the remaining months of 2007 (Exh. NEGC-JMS-2, Sch. G-10 (Rev.)). This modification reduces the three-year average bad debt ratio from 1.84 percent to 1.60 percent. The bad debt ratio of 1.60 percent for NEGC, when applied to the test year normalized distribution revenue of $28,935,369, produces an allowable bad debt expense of $462,966, resulting in an adjustment to the Company's test year cost of service of $284,256. In addition, applying the bad debt ratio of 1.60 percent to the approved revenue increase of $5,072,696 results in an additional adjustment of $81,163. Accordingly, NEGC shall adjust its test year level of bad debt expense of $178,709 by $365,419 ($284,256 + $81,163).

F. <u>Postage Expense</u>

During the test year, NEGC booked $280,366 in postage expense (Exh. NEGC-JMS-2, Sch. G-11). NEGC proposes to increase test year postage expense by $3,569 to incorporate a postage increase that became effective on May 11, 2009, for the full twelve months from January 1, 2009, to December 31, 2009 (<u>See</u> Exhs. NEGC-JMS-1, at 24; NEGC-JMS-2, Sch. G-11; NEGC-JMS-3, WPs G-11, G-11.1, G-11.2; DPU-NEGC-1-21). This adjustment produces a customer billing postage amount of $283,935 (Exhs. NEGC-JMS-2, Sch. G-11; NEGC-JMS-3, WPs G-11, G-11.1, G-11.2). No intervenor commented on NEGC's proposed postage expense adjustment on brief.

The Department recognizes postage expense as a legitimate cost of doing business. If a postage rate increase occurs prior to the issuance of an Order, the increase is eligible for inclusion in cost of service as a known and measurable change to test year expense. D.P.U. 08-35, at 108; D.P.U. 05-27, at 194; D.P.U. 03-40, at 174-175; <u>Massachusetts American Water Company</u>, D.P.U. 88-172, at 23-24 (1989); <u>Massachusetts Electric Company</u>, D.P.U. 800, at 29-30 (1982). A postage increase went into effect during the test year, on May 11, 2009 (Exh. DPU-NEGC-1-21, Att.; <u>see</u> <u>also</u> United States Postal Office press release: http://www.usps.com/communications/newsroom/2009/pr09_018.htm (February 10, 2009)). Therefore, the proposed increase is known and measurable. D.P.U. 08-35, at 108; D.P.U. 05-27, at 194; D.P.U. 90-121, at 118. Accordingly, the Department accepts the Company's proposed adjustment to postage expense of $3,569.

G. Management Support Cost Allocation

1. Company Proposal

a. Introduction

During the test year, NEGC booked $2,018,346 in management support services allocated from Southern Union (Exhs. NEGC-JMS-1, at 24; NEGC-JMS-2, Sch. G-12 (Rev.)). Southern Union allocates three categories of charges to NEGC: (1) joint and common costs ("JCC"); (2) service and management fees; and (3) royalty and license fees (Exh. NEGC-JMS-1, at 24).[125] JCC charges represent an allocation of actual employee and non-employee related costs, along with depreciation expense, that Southern Union incurs to support the operations of all of its divisions and subsidiaries (Exh. NEGC-JMS-1, at 24).[126]

b. Joint and Common Costs

Southern Union directly assigns to a division or subsidiary costs that are incurred on behalf of that entity using intercompany journal entries (Exh. NEGC-JMS-1, at 24). In the case of common charges, Southern Union implemented in 2004 a system of allocating common charges to each of its divisions and subsidiaries on a monthly basis using a three-factor formula, which the Company states is similar to the modified Massachusetts formula

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125 Service and management fees are not directly billed to NEGC, but rather consist of a journal entry derived by multiplying the Company's gross margin by 1.5 percent (Exh. AG-2-1, Att. B at 21; Tr. 1, at 111). In addition, Southern Union assesses each of its affiliates, including NEGC, a royalty and licensing fee equal to one percent of gross margins in exchange for the right to use certain trademarks, trade names, and service marks (Exh. AG-2-1, Att. B at 21).

126 NEGC removed from its cost of service the following costs allocated from Southern Union: (1) $434,212 in service and management fees; and (2) $289,475 in royalty and license fees (Exhs. NEGC-JMS-1, at 24; NEGC-JMS-2, Sch. G-12 (Rev.)).

(Exhs. NEGC-JMS-1, at 24; NEGC-JMS-3, WP G-12.3.2; AG 2-1, Att. B at 15-16; AG-10-7, at 1-2; Tr. 7, at 847-851).[127] Southern Union's formula allocates on an equal basis (1) investment by Southern Union, (2) net margin, and (3) total capital and operating expenses (Exhs. NEGC-JMS-3, WP G-12.3.2; AG-10-19).

First, corporate common costs are separated into three cost allocation pools (Exh. AG-10-19). Each cost allocation pool uses a separate three-factor formula based on an equal weighting of investment, net margin, and expenses to determine the portion of that expense to be charged to each of Southern Union's divisions and subsidiaries, including NEGC (Exhs. NEGC-JMS-3, WP G-12.3.2; AG-10-19; AG-10-22, Atts. B through D). The first allocation method, referred to as the "All Companies" method, is characterized by NEGC as a "default allocation methodology" that is applied to all divisions and subsidiaries (Exhs. NEGC-JMS-3, WP G-12.3.2; AG-10-19). The second allocation method, referred to as the "All Companies But Citrus" method, is applied to all divisions and subsidiaries except for Citrus (Exhs. NEGC-JMS-3, WP G-12.3.2; AG-10-19).[128] This allocation method is used

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127 The Massachusetts formula is a three-part allocator that uses a weighted average ratio comparing gross revenues, plant, and payroll. D.P.U. 08-27, at 85 n.47. The Commonwealth of Massachusetts originally developed the Massachusetts formula in 1919 for the purpose of apportioning income tax liabilities for companies with multi-state operations. See Acts of 1919, c. 355, § 19. Since that time, regulatory commissions across the United States have used this general approach and variations thereon, including the modified Massachusetts formula, to apportion common costs among utility companies that operated in multiple jurisdictions. D.P.U. 08-27, at 85-86 n.47.

128 According to NEGC, Citrus is excluded from certain cost allocations because Citrus is a more independent company that does not receive certain types of services from Southern Union (Exh. AG-10-20).

for all charges to the following corporate cost centers: (1) public affairs and communications; (2) investor relations; (3) legal; (4) executive; (5) environmental; (6) business unit allocations; and (7) business unit direct charges (Exh. AG-10-19). This allocation method is also used to apportion audit fees, debt-related fees, and a portion of employee benefit costs (Exh. AG-10-19). The third allocation method, referred to as the "LDC Only" method, is applicable only to NEGC, Missouri Gas, PEI, and NEG Appliance (Exhs. NEGC-JMS-3, WP G-12.3.2; AG-10-19). This allocation method relates to charges that originate within those divisions of PEPL that support the entire operations of Southern Union, and it is intended to ensure that PEPL, Southern Union, Southern Union Gas Services, and Citrus are not allocated costs that should be borne by LDC operations (Exh. AG-10-20).

In addition to these allocation methods, Southern Union makes certain adjustments relative to Citrus. Because Citrus is responsible for its own financial audits, audit-related expenses included in this cost allocation pool are separately deducted from expenses allocated to Citrus and reallocated among the remaining companies, including NEGC (Exhs. NEGC-JMS-3, WP G-12.3.1; AG-10-26; Tr. 7, at 838-839). In addition, Citrus's benefit-related expenses are adjusted so that benefit costs are matched with Citrus's actual payroll expense (Exhs. NEGC-JMS-3, WP G-12.3.1; AG-10-26). This modification was necessary to prevent an over-allocation of benefit expense to Citrus, because, although certain labor costs are not allocated to Citrus, payroll taxes and certain other employee benefits are allocated using the All Companies allocator (Exh. AG-10-26).

During the test year, NEGC booked $1,503,904 in JCC that had been allocated from Southern Union (Exh. NEGC-JMS-3, WP G-12.1). To determine its proposed level of JCC to include in cost of service, the Company first developed revised three-factor formulas applicable to 2010 and then applied the factors to the test year costs (Exh. NEGC-JMS-1, at 25). Based on revised allocators for All Companies of 1.818 percent, All Companies But Citrus of 2.656 percent, and LDC Only of 14.538 percent, NEGC derived a revised JCC expense of $1,449,581, representing a decrease of $144,328 to its test year JCC (Exhs. NEGC-JMS-1, at 25; NEGC-JMS-3, WPs G-12.1, 12.3.1, 12.3.2).

Next, the Company added $5,387 in various costs that had been identified as having been inadvertently omitted from the test year allocation (Exh. NEGC-JMS-3, WP G-12.5). Next, the Company removed the following allocated expenses: (1) $39,833 in costs relating to Southern Union's airplane subsidiary, SUGAir Aviation Company ("SUG Air"); (2) $42,759 in costs relating to Southern Union's operation of its New York offices; (3) $163,168 in costs relating to Southern Union's restricted stock options; (4) $5,597 in costs relating to Southern Union's supplemental retirement plan costs; (5) $1,996 in costs relating to Southern Union's out-of-period costs, charitable contributions, and promotional expenses; and (6) $13,202 in depreciation expense associated with fully-depreciated Southern Union plant and New York office leasehold changes (Exhs. NEGC-JMS-1, at 25; NEGC-JMS-3, WP G-12.1, WPs G-12.6 through G-12.10, G-12.12.1 through G-12.12.2; AG-1-98, Att.). In addition, the Company increased its JCC by $19,631 to adjust Southern Union salaries based on expected levels for

2011 (Exhs. NEGC-JMS-1, at 25; NEGC-JMS-3, WP G-12.11.1 through G-12.11.2). These adjustments produced a total revised JCC of $1,208,046 (Exh. NEGC-JMS-3, WP G-12.1).

The Company then reduced the $1,208,046 by $260,415, or 21.557 percent, to remove capitalizable JCC (Exhs. NEGC-JMS-1, at 25; NECG-JMS-3, WP G-12.1, G-12.13). Finally, NEGC removed $287 representing the lobbying and advertising portion of Southern Union's American Gas Association ("AGA") dues (Exhs. NEGC-JMS-1, at 25; NEGC-JMS-3, WP G-12.1, G-12.14). These changes resulted in an adjusted JCC allocated to NEGC of $947,343 (Exh. NEGC-JMS-2, Sch. G-12 (Rev.)).

c. Missouri Gas Allocations

In addition to JCC costs allocated from Southern Union, Missouri Gas also provides NEGC with accounts payable, purchasing, fleet management, executive oversight, and gas supply services (Exh. NEGC-JMS-1, at 25). During the test year, the Company did not book any costs allocated from Missouri Gas; rather, the Company's historic practice has been to compute the necessary adjustments as part of Missouri Gas's and NEGC's respective rate cases (Exhs. NEGC-JMS-2, Sch. G-12 (Rev.); AG-10-18).[129]

To recognize its labor and labor-related costs provided by Missouri Gas in the above areas, NEGC increased its management support cost allocation by $306,253

129 NEGC states that if the Department determines that booking these transfers directly through journal entries is preferable, the Company would have no objection to modifying its bookkeeping practices (Exh. AG-10-18).

(Exhs. NEGC-JMS-1, at 25; NEGC-JMS-2, Sch. G-12 (Rev.); RR-DPU-4).[130] The Company derived this expense by first multiplying the hourly rates of the ten Missouri Gas employees who also perform work for NEGC by the percentage of time they devoted to the Company's operations, and then adding a 68.45 percent loading factor to account for payroll taxes, benefits, and injuries and damages (Exhs. NEGC-JMS-3, WP G-12.15; AG-10-33; AG-10-33 Supp. & Att. B; RR-DPU-5, Att.). This loading factor consists of (1) a payroll tax loading factor of 7.67 percent, (2) an injuries and damages loading factor of 2.85 percent, and (3) a pension and benefits loading factor of 57.93 percent (Exh. AG-10-33, Att.).[131]

The sum of the $947,343 in JCC costs and $306,253 in Missouri Gas costs results in a total proposed management support cost allocation to NEGC of $1,253,596 (Exh. NEGC-JMS-2, Sch. G-12 (Rev.)). Consequently, the Company proposes an overall reduction to test year cost of service for management support of $764,750 (Exh. NEGC-JMS-2, Sch. G-12 (Rev.)).

d. Cost Allocation Manual

NEGC states that there are no written policies or procedures that specifically address its cost allocation method (Exh. AG-10-8). Southern Union's Missouri Gas operations, however,

130 NEGC did not include any of Missouri Gas's fleet management costs in its proposed cost of service (RR-DPU-4).

131 During the proceeding, the Company provided a revised combined loading factor of 69.93 percent, consisting of (1) a payroll tax loading factor of 7.84 percent, (2) an injuries and damages loading factor of 3.03 percent, and (3) a pension and benefits loading factor of 58.46 percent (Exh. AG-10-33 Supp., Att. B). NEGC stated that it is not proposing to use this higher, revised loading factor (Exh. AG-10-33 Supp.).

rely on a cost allocation manual ("Missouri CAM") that is filed annually with the Missouri Public Service Commission (Exh. AG-2-1, Atts. A, B). According to NEGC, there are no differences between the cost allocation policies and procedures described in the Missouri CAM and those applied to the Company (Exhs. AG-10-3; AG-10-6).

2. Positions of the Parties

a. Attorney General

i. Joint and Common Costs Allocation

The Attorney General asserts that Southern Union is allocating an excessive level of costs to NEGC because (1) the costs are based on inappropriate allocation factors that are not reflective of cost causation principles, and (2) there are certain costs that should not be recovered from NEGC ratepayers (Attorney General Brief at 17, 18-19, 30-32). The Attorney General proposes to reduce the Company's proposed JCC expense by $192,472 (Attorney General Brief at 17-18, citing Exh. AG-DR at 3). This adjustment produces a revised JCC of $754,871.

In arguing that NEGC's proposed JCC allocation is based on inappropriate allocation factors, the Attorney General first acknowledges that a multi-factor approach, such as a three-or four-factor formula, can result in a reasonable weighting of overall cost drivers, and can be an appropriate means of allocating joint and common corporate costs that benefit multiple subsidiaries or divisions (Attorney General Brief at 20-21, citing Exh. AG-DR at 8). Nevertheless, the Attorney General contends that the three-factor formula the Company employs differs substantially from the widely accepted modified Massachusetts formula, and does not meet the criterion of reflecting reasonable and appropriate cost causation principles (Attorney General Brief at 21, citing Exhs. AG-DR at 9; AG-10-7; Attorney General Reply Brief at 4).

First, the Attorney General maintains that the Company's selection of an investment category as a basis for the three-factor formula is inappropriate (Attorney General Brief at 22). According to the Attorney General, the use of an investment category for this portion of the three-factor formula results in the inclusion of inappropriate items such as goodwill, regulatory assets, other deferred charges, equity investments, and long-term receivables (Attorney General Brief at 22, citing Exh. AG-DR at 9-10; Tr. 7, at 825-826; Attorney General Reply Brief at 4). Therefore, the Attorney General proposes that the Company's investment category be replaced with a net-plant-in-service category for purposes of computing the three-factor formula (Attorney General Brief at 23).

Second, the Attorney General argues that the Company's selection of a total capital and operating expense category as a basis for the three-factor formula should be replaced with an operating and general expenses category (Attorney General Brief at 18, 23). According to the Attorney General, the Company's capital and operating expense category includes not only operating and general expenses, but also includes other inappropriate components such as (1) taxes other than income taxes, (2) depreciation expense, and (3) royalty and management fees (Attorney General Brief at 23, citing Exh. AG-DR at 12). As further explained below, the Attorney General argues that the use of an operating and general expense category will ensure that costs are allocated on the basis of cost causation principles and avoid placing excessive weight on several of the factors (Attorney General Brief at 23, citing Exh. AG-DR at 13-14).

In support of her proposed operating and general expenses allocator, the Attorney General first argues that the Company's "total capital and operating expenses" category includes royalty and management fees Southern Union charges to NEGC that are based on a 2.5 percent of net sales margin (Attorney General Brief at 24, citing AG-DR at 13-14). The Attorney General maintains that this fee is not a cost driver for Southern Union, and further points out that NEGC has acknowledged that royalty and management fees should be excluded from cost of service (Attorney General Brief at 24, citing Exh. NEGC-JMS-1, at 22). To ensure that NEGC's cost allocation factors are consistent with this treatment, the Attorney General proposes to exclude the Company's royalties and management fees from her expense category when determining the appropriate allocation factor (Attorney General Brief at 24).

The Attorney General further advocates that depreciation expense be excluded from the three-factor formulas (Attorney General Brief at 24). According to the Attorney General, because depreciation accruals are a factor in the determination of net plant, the Company's net plant allocator already takes depreciation expense into consideration (Attorney General Brief at 24, citing Exh. AG-DR at 13). Consequently, she maintains that inclusion of a separate depreciation expense component in conjunction with the use of a net plant allocator would result in an over-weighting of plant investment when determining cost causation (Attorney General Brief at 24, citing Tr. 7, at 846-847).

Finally, the Attorney General proposes to exclude the taxes other than income taxes category of expenses from her calculation of the expense component of the three-factor formula (Attorney General Brief at 25). The Attorney General maintains that taxes other than income taxes typically are not included under either the modified Massachusetts formula or similar allocation methods, because (1) property taxes are not considered to be a major cost driver and (2) property taxes are largely a function of plant investment, which is already recognized in a separate category (Attorney General Brief at 25, citing Tr. 7, at 850; Attorney General Reply Brief at 5-6). Similarly, the Attorney General contends that payroll taxes are not a driver of corporate costs, and, in any event, are already recognized through the Company's use of a payroll cost component (Attorney General Brief at 25, citing Exh. AG-DR at 13; Attorney General Reply Brief at 5).

In addition to her concerns about the calculation of NEGC's three-factor formula, the Attorney General disputes the Company's "All Companies But Citrus" allocation method. First, the Attorney General maintains that the labor costs associated with Southern Union's investment relations and executive departments should be allocated to all Southern Union companies, including Citrus (Attorney General Brief at 27, citing Exh. AG-DR at 16-17; Tr. 7, at 35-36; Attorney General Reply Brief at 6). Second, the Attorney General contends that Southern Union's corporate depreciation expense should also be allocated to all Southern Union companies, including Citrus (Attorney General Brief at 27, citing Exh. AG-DR at 17). Finally, the Attorney General argues that, consistent with her recommendation that a portion of Southern Union's payroll expense for its investment relations and executive departments be allocated to Citrus, the maximum percentage of costs applicable to the Citrus component used to allocate employee benefits expense should be increased to 74.24 percent (Attorney General Brief at 29-30, citing Exh. AG-DR at 19).

Turning to specific Southern Union expenses, the Attorney General also argues that Southern Union inappropriately seeks to allocate a portion of $351,253 in expenses to NEGC (Attorney General Brief at 30-32, citing Exhs. AG-DR at 24-25; AG-DR-5). This includes: (1) $3,000 in out-of-period membership fees for the Council on State Taxation paid on behalf of Southern Union; (2) $135,015 in consulting expenses paid to a public relations firm; (3) $154,032 representing a change in the market value of diversified assets; (4) a negative $132,806 in rental income associated with Southern Union's operation of its New York offices;[132] and (5) $192,012 in franchise tax audit-related costs (Attorney General Brief at 31-32, citing Exhs. AG-DR at 24-26; AG-DR-5). The Attorney General argues that the Department should exclude NEGC's allocated share of these costs, totaling $6,737, from the total allocation included in the Company's cost of service (Attorney General Brief at 31-32, citing Exh. AG-DR-5). In addition to these costs, the Attorney General argues that the Department also should exclude all incentive compensation costs from the pool of costs included in the JCC (Attorney General Brief at 31).

132 The Attorney General notes that because the rental costs associated with the operation of Southern Union's New York City offices were removed, the associated rental income from subtenants should also be excluded (Attorney General Brief at 32, citing Exh. AG-DR at 26).

ii. Missouri Gas Allocations

The Attorney General asserts that NEGC's adjustment to increase its test-year expenses for support it receives from Missouri Gas is not fully supported by the evidence and includes inappropriate costs (Attorney General Brief at 32-33). She maintains that Missouri Gas allocated a significantly higher proportion of costs in the test year than in previous years (Attorney General Brief at 33, citing Exhs. AG-DR at 29; AG-10-33(e)). The Attorney General asserts that, in fact, the costs allocated to NEGC differ from those provided in the Missouri CAM filed with the Missouri Public Service Commission (Attorney General Brief at 35, citing Exh. AG-DR at 20-31).

In addition to contesting an increase in costs allocated from Missouri Gas to NEGC, the Attorney General also disputes an increase in the loading rate used by the Company from 68.45 percent to 69.33 percent to gross up the additional benefit and tax costs associated with Missouri Gas employees performing work on behalf of NEGC (Attorney General Brief at 33-34). Not only does the Attorney General contend that the relevant information was received on an untimely basis, she also argues that the 58.46 percent pension and benefits loading rate component of the loading charge inappropriately includes stock options, amortization of Financial Accounting Standards No. 106 ("FAS 106") benefits,[133] and pensions/retirement power account (Attorney General Brief at 34-35, citing Exh. AG-10-33 Supp., Att. B at 16). The Attorney General asserts that excluding these costs

[133] FAS 106 establishes accounting standards for employers' accounting for PBOP and requires accrual rather than cash (pay-as-you-go) accounting for these expenses.

from the loading rate calculation would reduce the pension and benefits loading rate component from 58.46 percent to 49.14 percent, and would produce a combined loading charge similar to that reported during the test year (Attorney General Brief at 35, citing Exh. AG-DR at 28). The changes proposed by the Attorney General result in a reduction in the Missouri Gas allocation of $19,254 (Attorney General Brief at 33, 35, citing Exh. AG-DR at 28).

iii. Cost Allocation Manual

The Attorney General asserts that, despite the large amount of JCC being allocated to NEGC, Southern Union does not have a detailed cost allocation manual that it uses in allocating such costs to NEGC (Attorney General Brief at 35). She contrasts this situation to that of Missouri Gas, which files its Missouri CAM on an annual basis with the Missouri Public Service Commission (Attorney General Brief at 35, citing Exh. AG-DR at 29).

Although Missouri Gas has a cost allocation manual, the Attorney General maintains that the Missouri CAM lacks necessary details and is a high-level document as opposed to a cost manual. The Attorney General points out that there is: (1) no indication in the Missouri CAM that the Company uses three separate factors in allocating JCC; (2) no mention of Southern Union's internal department involved in providing service or the cost type to which each of the separate three factors are applied; (3) no indication that Citrus is excluded from many of the cost allocations; and (4) no mention of how PEPL allocates costs to Southern Union that are then re-allocated to LDCs only (Attorney General Brief at 36). In addition, the Attorney General points out that the Company concedes that there are no written policies and procedures specifically addressing the cost allocation method in use (Attorney General Brief at 36, citing Exh. AG-DR at 29-31).

In view of her identification of numerous problems with both the cost allocation method and the costs that are included in the allocations, the Attorney General asks that the Department direct NEGC to produce and maintain a detailed cost allocation manual that identifies all of its cost allocation methods, policies, and procedures (Attorney General Brief at 36-37). The Attorney General also requests that the Department require the Company to provide such a manual whenever revisions are made to the allocation method (Attorney General Brief at 37, citing Exh. AG-DR at 29-31).

b. Company

i. Introduction

NEGC asserts that the allocation method used to apportion JCC is appropriate and, as such, that the Department should reject the Attorney General's recommendations (Company Brief at 30). The Company also maintains that the costs incurred for services received from Missouri Gas are appropriate and, thus, that the Department should also reject the Attorney General's proposed disallowance (Company Brief at 30).

ii. Joint and Common Costs Allocation

The Company asserts that Southern Union's allocation method is similar to the modified Massachusetts formula, which is widely accepted within the utility industry and which the Department approved in D.P.U. 08-35, and the Missouri Public Service Commission has adopted (Company Brief at 28, citing Exhs. AG-10-7; AG-10-19; AG-10-20; Company Reply

Brief at 21-22). NEGC argues that the Attorney General's proposed cost allocation method ignores cost causation principles (Company Brief at 28).

According to the Company, the Attorney General fails to provide any Department precedent on disallowing the costs in the allocators in dispute (Company Brief at 28, <u>citing</u> Tr. 7, at 826-827). Moreover, the Company defends its use of a total capital and operating expense component in its three-factor formula, claiming that due to the variation in tax rates and the variation in Company employees' payroll subject to those different tax rates, payroll expense cannot be a comprehensive cost driver (Company Brief at 29, <u>citing</u> Tr. 7, at 829-833). NEGC contends that the inclusion of payroll taxes as well as payroll expense is appropriate, and that the Attorney General fails to provide any compelling argument against their inclusion in the three-factor formula (Company Reply Brief at 21).

With regard to Citrus, the Company asserts that Southern Union's investor services and executive departments do not provide support to Citrus and, therefore, it would be inappropriate to allocate those costs to Citrus (Company Brief at 29, <u>citing</u> Exhs. AG-10-19; AG-10-20). NEGC maintains that the Attorney General's argument that Southern Union provides support to Citrus in those areas is mere speculation rather than fact based on record evidence (Company Brief at 30, <u>citing</u> Tr. 7, at 835-836).

NECG contends that its three-factor formula has been in place since 2004, and that this automated system fairly apportions common costs among all of Southern Union's operations (Company Reply Brief at 21-22). The Company maintains that adoption of the Attorney General's proposal would require manual adjustments (Company Reply Brief at 22). NEGC asserts that while these manual adjustments would add a greater level of complexity to the allocation of common costs, the net results would produce cost differences that are not significant enough to justify the expenditure that would be required (Company Reply Brief at 22).

iii. Missouri Gas Allocations

The Company argues that the Attorney General incorrectly asserts that NEGC failed to provide a reasonable level of support for the costs allocated from Missouri Gas and, specifically, for the loading rate (Company Brief at 30). The Company maintains that it has fully justified the loading rate and that its proposed costs should be approved (Company Brief at 30, citing Exh. AG-10-33 Supp.).

3. Analysis and Findings

a. Introduction

Southern Union is a stand-alone operating company; NEGC and Missouri Gas do not operate as wholly owned subsidiaries, but rather as divisions of Southern Union (Exh. AG-1-98, Att.). Nevertheless, Southern Union's system of allocating JCC to its divisions and subsidiaries is the same as a utility holding company uses to allocate common costs among regulated and nonregulated subsidiaries, whether directly from a parent or through the use of a service company. See D.P.U. 09-39, at 245-247; D.P.U. 08-27, at 78, 83-86; D.P.U. 05-27, at 220-221. Therefore, the Department will examine NEGC's allocated costs from Southern Union and Missouri Gas using the affiliate transaction standard.

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; D.P.U. 89-114/90-331/91-80 Phase One at 79-80; Milford Water Company, D.P.U. 92-101, at 42-46 (1992); D.P.U. 85-137, at 51-52. In addition, 220 C.M.R. § 12.04(3) provides that an 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.

The services Southern Union provides to NEGC are necessary to the Company's business, and thus specifically benefit NEGC. Moreover, these activities do not duplicate services provided by the Company's local personnel. Nevertheless, the Attorney General has raised issues concerning the total expense attributable to and allocation of the JCC, as well as the total expense attributable to and allocation of costs from Missouri Gas. The Attorney General also raises issues about NEGC's documentation of its cost allocation system. Each of these contested issues is discussed in detail below.

b. Joint and Common Costs Allocation

i. Allocation Factors

The Attorney General contends that the Company's proposed JCC costs are based on inappropriate allocation factors, and that several modifications are warranted (Exh. AG-DR at 20). The Attorney General further argues that certain costs allocated through the JCC should not be recovered from NEGC's ratepayers (Exh. AG-DR at 22-26). In response, the Company maintains that both its allocation factors and the underlying costs are justified and should be accepted (Company Brief at 30).

The Massachusetts formula is a well-established allocation method that is familiar to utilities and regulators. For many years, federal and state regulatory commissions have recognized both the original Massachusetts formula and those variations that have developed over time as suitable allocation methods (see Exhs. AG-10-7(a); AG-DR at 7-8). See also D.P.U. 08-27, at 85 n.47; Eastern Edison Company, D.P.U. 1130, at 29-31 (1982). Regardless of the particular allocation method ultimately selected, the Department requires that the allocation method be driven by cost causation principles. D.P.U. 85-137, at 51-52. The Department will now examine the Company's allocation methods.

The Attorney General contends that the Department should direct the Company to replace the investment component of its three-factor formula with a net plant allocation component, in order to eliminate from the calculations non-plant related items such as goodwill, regulatory assets, other charges, equity investments, and long-term receivables (Attorney General Brief at 22, citing Exh. AG-DR at 10-11). The Company maintains that the

Attorney General has offered no evidence to justify the exclusion of these components from its allocation method (Company Brief at 28-30). The Company's derivation of its investment allocator, however, demonstrates that goodwill and regulatory assets represent 54.6 percent of the total investment ascribed to NEGC (Exh. AG-10-22, Att. A). The Department is unpersuaded that balance sheet components such as goodwill and regulatory assets are appropriate cost drivers for NEGC. Moreover, the components are not generally included in rate base. Therefore, we find that NEGC's proposed investment allocator is not based on cost causation. Therefore, we accept the Attorney General's proposed modification of the Company's three-factor formula to rely on net plant instead of net investment in its calculation.

The Attorney General also argues that the Department should replace the total capital and operating expense component in NEGC's three-factor formula with an operating and general expenses allocation component, in order to eliminate the effects of double counting the effect of expenses such as royalty and management fees, depreciation expense, and property and payroll taxes (Attorney General Brief at 23-25). We cannot reasonably interpret the royalty and management fees Southern Union assesses on its divisions and subsidiaries to be cost drivers. Insofar as the Company has excluded royalty and management fees from cost of service, these expenses are no longer factors in NEGC's cost to provide service to its customers.[134] The Company contends that different tax rates and Social Security tax payments

134 Although NEGC has not sought rate recovery of these expenses, we find it appropriate to comment upon these types of costs in general. As the Department has stated previously, "holding companies, in their efforts to derive income in addition to that obtained through dividends, frequently resort to all sorts of contractual relations with the operating utilities which they control. These contracts in any rate proceeding

warrant the inclusion of payroll and property taxes in the allocator. Payroll and property taxes, as well as depreciation expense, are functions of payroll expense and plant investment, and thus are already components of the operating and general expenses and net plant allocators. Therefore, inclusion of these taxes and depreciation in the Company's three-factor formula would distort the resulting allocator. The Department finds that NEGC's proposed operating expense allocator is not based on cost causation. Therefore, we accept the Attorney General's proposed modification of the Company's three-factor formula to rely on an operating and general expenses allocation component.

Based on our findings above, the Department accepts the use of the Attorney General's proposed three-factor allocators. Accordingly, we will use the following allocators to determine the level of management support costs the Company may include in its cost of service:

All Companies	1.9180 percent
All Companies But Citrus	2.5977 percent
LDCs Only	12.5207 percent

We now address the proposed allocation of costs among Southern Union's divisions and subsidiaries. The Attorney General argues for several modifications to the Company's

necessarily are subject to suspicion and to careful scrutiny." Boston Edison Company/Boston Edison Mergeco Electric Company, D.P.U./D.T.E. 97-63, at 63 n.20 (1998), citing Department of Public Utilities 1932 Annual Report to the Legislature at 7. The Company-excluded expenses are examples of the types of charges that the Department found troublesome as far back as 1932. Given that background, rate recovery of royalty fees and undefined management expenses is highly unlikely.

allocations to Citrus. First, the Attorney General proposes that a portion of labor costs associated with Southern Union's investor relations, communications, environmental, legal, and executive departments be allocated to Citrus (Attorney General Brief at 26, citing Exh. AG-DR at 6-7, 16). Southern Union and El Paso operate Citrus as a joint venture, with PEPL bearing the primary responsibility for management of Citrus (Exhs. AG-1-2, Att. 2, at 4; AG-10-19). Moreover, Southern Union recognizes Citrus as an equity investment (Exhs. AG-1-2, Att. 1, at 21, 97; AG-10-19). However, we must consider these facts in conjunction with all of the evidence in this case. There is uncontroverted evidence that Southern Union allocates costs related to other Southern Union divisions to Citrus (Exh. AG-10-19, Att. at 5-28). For example, Southern Union allocates costs relating to its accounting, risk management, treasury, taxes, information technology, human resources, and internal audit divisions (see, e.g., Exh. AG-10-19, Att. at 4). Under these circumstances, we are unpersuaded that Southern Union's executive operations are as remote from Citrus as the Company argues. Accordingly, the Department finds that the Company has failed to substantiate its argument that none of Southern Union's executive costs should be allocated to Citrus. Therefore, using the information provided in Exhibit AG-10-19, we have reallocated executive expense using the "All Companies" allocator as opposed to the "All Companies But Citrus" allocator. The effect of this executive-related adjustment on the Company's allocated share of Southern Union's common costs is provided below.

The Attorney General also proposes that an appropriate level of depreciation expense be allocated to Citrus (Attorney General Brief at 26). According to the Company, Southern

Union ceased its prior practice of allocating depreciation expense to Citrus in December of 2006, because of Citrus's status as a jointly-held business and because of questions as to whether Southern Union's joint operating agreement with El Paso would permit the allocation of depreciation expenses to Citrus (Exh. AG-10-31; RR-DPU-62). Section 2.01 of Article II of the joint operating agreement provides:

> All ordinary and necessary costs associated with the direct operation of Citrus shall be accrued and paid by Citrus. Such costs shall include, but not be limited to, direct operating expense, repairs, maintenance, capital additions and replacements, retirements, abandonments, and direct administration. Any costs or expenses incurred by Operator in rendering direct operating services to affiliates or subsidiaries of Operator that are not related to Citrus shall be allocated to such affiliate or subsidiary and not to Citrus.

(RR-DPU-63).

Southern Union incurs depreciation expense on its assets (Exh. AG-10-19, at 5-28). Depreciation expense is unquestionably an ordinary and necessary cost for any business. We do not see that the joint operating agreement prohibits the allocation of depreciation expense to Citrus. Moreover, regardless of the other arrangements that may exist between Southern Union and El Paso, it would be inequitable to compel NEGC's customers to subsidize Citrus's operations. The Department finds that the Company has failed to justify the exclusion of depreciation expense to Citrus. Therefore, using the information provided in Exhibit AG-10-19, we have reallocated depreciation expense using the "All Companies" allocator instead of the "All Companies But Citrus" allocator. The effect of this depreciation-related adjustment on the Company's allocated share of Southern Union's common costs is provided below.

Because Southern Union uses two different allocators for payroll expense and related benefits, the above change to the allocation of executive expenses also affects the maximum benefits expense allocable to Citrus. Using the information provided in Exhibit AG-10-26 and Record Request DPU-59, the Department has recalculated the appropriate allocation factor by removing \$151,994 in payroll associated with Southern Union's investor service department from the total allocable payroll expense of \$10,091,567, producing a revised allocable payroll expense of \$9,939,573. This amount, divided by total payroll expense of \$13,953,213 provided in Record Request DPU-59, produces a revised allocation factor of 73.122 percent. Accordingly, the Department will apply a maximum benefits allocation to Citrus of 73.122 percent.

Application of the revised three-factor formulas to the information provided in Record Request DPU-59, as well as the reallocation of executive payroll expense and revised maximum allocator to Citrus, results in an adjusted test year JCC of \$1,354,847 for NEGC. Therefore, the Department will use this revised test year JCC as the basis for determining the level of JCC to include in the Company's cost of service.

ii. Cost Components Subject to Allocation

NEGC has proposed a total net reduction of \$241,537 to its adjusted test year JCC representing various items, including adjustments for previously unrecorded expenses, costs relative to SUG Air, restricted stock options, Southern Union's operation of its New York offices, supplemental retirement plans, assorted miscellaneous expenses, and depreciation expense (see Exh. NEGC-JMS-1, at 24-25). The Company's allocated portion of these expenses is derived from the allocators that were calculated based on the three-factor formulas (Exhs. NEGC-JMS-1, at 25; NEGC-JMS-3, WP G-12.1). Consistent with the revised three-factor formulas derived above, the Department has recalculated the Company's adjustments. As a result of this recalculation, the total net reduction to NEGC's revised test year JCC expense is $242,177, producing a net revised JCC of $1,111,104.

The Attorney General proposes a number of additional adjustments to the Company's JCC. The Attorney General proposes to remove $107,280 in Southern Union incentive compensation expense (Exh. AG-DR at 24). The Department has excluded these expenses from the Company's cost of service (see Section V.3.b., above). As the Department has already excluded these costs from NEGC's cost of service, removing these expenses from the Company's management support expense would constitute double counting. Therefore, the Department finds that no further adjustment for incentive compensation is required.

The Attorney General identifies five additional categories of expenses, totaling $351,253, that she maintains should be excluded from the total pool of costs allocated under the JCC (Exh. AG-DR at 22-26). The Company does not specifically challenge the Attorney General's proposed exclusions. First, the Attorney General proposes to exclude $3,000 in dues paid to the Council on State Taxation. The evidence demonstrates that the annual dues to this organization are $3,000, and that the Company included both its 2009 and 2010 membership dues in its proposed cost of service (Exh. AG-10-11, Att. B). It is inappropriate to include two annual payments in a single twelve-month test year. D.P.U. 86-280-A at 81.

Accordingly, the Department will remove $3,000 in dues from the pool of common costs to be allocated to NEGC.

Second, the Attorney General proposes to exclude $135,015[135] in costs associated with Sard Verbennin & Company, because the costs in the nature of a lobbying type of activity that benefits shareholders rather than ratepayers (Exh. AG-DR at 25). The Department's long-standing policy is to exclude lobbying activities from cost of service. New England Telephone and Telegraph Company, D.P.U. 86-33-G at 101 (1989); D.P.U. 1720, at 70-78. Based on review of the firm's billings, the Department concludes that this firm's primary role for Southern Union is not lobbying, but rather communications consulting in high-profile situations, such as may be expected in gas-related incidents and environmental litigation (Exh. AG-DR at 25; RR-DPU-64, Att.). The Department finds these types of activities to be legitimate operating expenses. D.P.U. 89-114/90-331/91-80 (Phase One) at 131-132; D.P.U. 86-33-G at 146. Nonetheless, in reviewing the invoices, we determine that the Company has provided insufficient evidence to demonstrate that the costs are known and measurable (RR-DPU-64, Att.). Specifically, for two months, the invoices delineate work performed, totaling $25,015 (RR-DPU-64, Att.). The remaining invoices are monthly retainers and do not specify any actual work that Sard Verbinnin & Company performed on behalf of Southern Union (RR-DPU-64, Att.). See D.T.E. 05-27, at 241-242. Thus, we find

135 In asserting that $135,015 should be removed from the pool of common costs, the Attorney General has misread the Company's exhibit, which states that $10,000 previously had been removed due to a 2008 year-end accrual, leaving $125,015 relating to Sard Verbennin & Company (RR-DPU-64, Att. at 1).

it appropriate to include only $25,015 and remove the remaining $100,000 from the pool of common costs to be allocated to NEGC.

Third, the Attorney General proposes to remove $154,032 in expenses related to a "change in [market] value of diversified assets" (Exh. AG-DR at 26). The expense appears to be an accounting accrual entry (Exh. AG-10-25, Att. B). There is no information on the purpose of the accounting entry, the nature of these diversified assets, or whether the accounting adjustments have any ratemaking implications. In the absence of additional information on this particular activity, the Department will remove $154,032 in expenses related to this accounting adjustment from the pool of common costs to be allocated to NEGC.

Fourth, the Attorney General has proposes to remove $132,806 in sub-tenant rental income being derived from Southern Union's New York offices because the Company has removed the corresponding rental expense from cost of service (Exh. AG-DR at 26). Southern Union regularly uses the New York offices for meetings with investors, bankers, and credit rating agencies, as well as for the primary office of Southern Union's chairman of the board and his staff and the investor relations department (Exh. AG-10-32). Because of prior rate agreements in connection with Missouri Gas, the Company has elected to exclude the associated rent expense, leasehold improvement amortizations, and artwork from the cost of service of its gas distribution operations (Exh. AG-10-32).[136] Because the Company has removed NEGC's allocated share of these expenses from its proposed cost of service, the

136 NEGC has included the furniture, computer equipment, and other related items located at the New York offices in its depreciation expense calculations (Exh. AG-10-32).

Department finds it appropriate to remove the associated revenues so that all of the benefits derived from these subleases are properly assigned to the shareholders who are bearing all of the associated costs. See Lowell Gas Company, D.P.U. 19037/19037-A at 17 (1977); Cape Cod Gas Company, D.P.U. 19036/19036-A at 13-14 (1978). Accordingly, the Department will increase the pool of common costs to be allocated to NEGC by $132,806.

Fifth, the Attorney General proposes to remove $192,012 in costs related to an audit of the Company's Massachusetts franchise taxes for the years 2004 through 2007. This audit took place during the test year (Tr. 8, at 963-964). Based on the Company's description of this activity, the Department considers these audits to be periodically recurring activities. Test year expenses that do not recur on an annual basis but rather are demonstrated to recur periodically over time are normalized so that the cost of service will include only the appropriate portion of the expense. D.P.U. 93-60, at 170. This allocation is determined by examining the cycle of the expense and apportioning only an annualized amount to the cost of service. D.P.U. 1270/1414, at 33. Based on the four years of Massachusetts franchise taxes that were the subject of the audit, and the two-year period between 2007, which was the final year included in the audit, and the 2009 test year, the Department concludes that a six-year normalization of expense produces a reasonable level of audit expense to include in cost of service. Normalizing the $192,012 in audit expense over six years produces an annualized audit expense of $32,002. Accordingly, the Department will remove $160,010 in audit expense from the pool of common costs to be allocated to NEGC.

iii. Joint and Common Costs Conclusion

To derive the allowable JCC expense, the Department has first reduced the Company's test year allocation to NEGC of $1,593,909 by $239,062 to recognize both the 2010 pool reallocations and the revised three-factor formulas as determined above. From this net expense of $1,354,847, the Department has also removed the various Company-proposed adjustments, as revised based on the revised three-factor formulas. These total adjustments of $238,644, along with a reduction of $5,452 in miscellaneous adjustments offered by the Attorney General,[137] result in a total adjusted JCC of $1,110,752. After deducting 21.557 percent, or $239,445 in capitalized amounts, as well as a revised American Gas Association lobbying expense of $281 derived from the revised allocators, the total allowable JCC expense is $871,026.

c. Missouri Gas Allocation

The allocations from Missouri Gas consist exclusively of payroll expense and payroll-related items, such as benefits (Exh. NEGC-JMS-3, WP G-12.15). Therefore, the Department has examined the allocation method used to apportion Missouri Gas costs to NEGC.

137 The $5,452 in miscellaneous expenses is derived by first removing (1) $3,000 reduction in membership dues, (2) $100,000 reduction in Sard Verbennin & Company retainer fees, (3) $154,032 reduction relating to diversified assets, (4) $132,806 increase in rental income, and (5) $160,010 reduction in audit fees. The resulting sum of $284,236 was then multiplied by the revised allocation factor of 1.918 percent (All Companies), providing an initial allocation to NEGC of $5,452.

The Company's payroll allocations are based on the number of invoices processed by those Missouri Gas employees providing accounts payable services, and based on discussions with other Missouri Gas employees as to their specific tasks and estimates (Exh. AG-10-33). The Department has previously criticized payroll expense allocations based on estimates. Cape Cod Gas Company/Lowell Gas Company, D.P.U. 18571/18572, at 8-10 (1976). Nonetheless, in this situation, the Department has compared the estimates provided by Missouri Gas's employees with their specific duties, and taken into consideration the relative sizes of NEGC and Missouri Gas. Based on this comparison, and the additional consideration that the Company has not included Missouri Gas's fleet management services in its allocation, the Department is satisfied that the estimates provided by Missouri Gas employees present a reasonable basis on which to determine the proportion of their total expense that should be allocated to NEGC (Exh. AG-10-33; RR-DPU-4; RR-DPU-5). Therefore, the Department accepts the Company's proposed payroll expense of $181,807.

Turning to the 68.45 percent loading factor used by Missouri Gas, this factor was derived based on actual data for 2009, adjusted for wage and salary increases granted to Missouri Gas employees (Exh. AG-10-33, Att.; RR-DPU-5).[138] The Attorney General contests the Company's pension and benefits loading factor, arguing that the factor contains inappropriate expenses such as $2,664,792 in FAS 106 amortization, $524,877 in other pension-related expenses, and $562,381 in stock options (see Exh. AG-10-33 Supp., Att. B

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138 As noted in n.130, above, NEGC provided a revised loading factor of 69.33 percent, however, the Company indicated that it was not proposing to use this higher revised loading factor (Exh. AG-10-33 Supp.).

at 6). Concerning Missouri Gas's FAS 106 amortization and other pension-related expenditures, NEGC has a reconciling pension/PBOP adjustment factor ("PAF") through which it recovers these costs as part of the LDAC. New England Gas Company, D.P.U. 08-66/09-93, at 1 (2010). The Company's PAF mechanism, however, does not make provision for pension-related costs that are not directly allocated to the Company, but rather only recognizes such costs through a cost of service adjustment submitted as part of a general rate case (Exhs. NEGC-JDS-1-15, at 9-11; AG-10-18). Therefore, the Department will include the FAS 106 amortization and other pension-related costs in the Company's pension and benefits loading factor.

Turning to the stock options expense, Missouri Gas booked $562,381 in stock option expense during the test year (Exh. AG-10-33 Supp., Att. B at 6). Consistent with our treatment of stock options above, the Department will exclude $562,381 in stock option expense from the total $23,529,302 in Missouri Gas's pension and benefits expense. This adjustment produces a revised pension and benefits expense of $22,966,921, and a revised pension and benefits loading factor of 57.07 percent.

The revised 57.07 percent pension and benefits loading factor, combined with the proposed payroll tax loading factor of 7.84 percent and proposed injuries and damages loading factor of 3.03 percent, produce a total loading factor of 67.94 percent. Application of this loading factor to the $181,807 in payroll expense produces a total loading charge of $123,520, and a total Missouri Gas expense allocation to NEGC of $305,327. The Company has proposed an increase to test year cost of service for Missouri Gas allocations of $306,253

(Exh. NEGC-JMS-2, Sch. G-12 (Rev.)). Accordingly, the Department will reduce the Company's proposed cost of service by $926.

Based on the foregoing analysis, the Department finds that the allowable level of expenses allocated from Missouri Gas is $305,327. Accordingly, the Department will use this revised expense level to determine the Company's management support expense to be included in its cost of service.

d. Cost of Allocation Manual

The Company indicates that the procedures and policies contained in the Missouri CAM are equally applicable to the operations of NEGC (Exhs. AG-2-1, Att. B; AG-10-3). The Missouri CAM makes reference to the JCC, and includes as one of its appendices a reference to certain electronic files that are used in the JCC model (Exhs. AG-2-1, Att. B at 11; AG-10-9, Atts. A through O).

The Department has reviewed the Missouri CAM, including the electronic spreadsheets. While the Missouri CAM includes some description of the JCC, such as the use of a three-factor formula, and provides electronic spreadsheets showing how the allocation formulas work, the Missouri CAM lacks the level of narrative needed to understand the mechanics of the allocators or how the various calculations interact with one another (Exh. AG-10-9, Atts. A through O). The Company has conceded that there are no written policies and procedures specifically addressing the cost allocation method (Exh. AG-10-8). Without written documentation describing the procedures Southern Union uses to allocate costs among its various divisions and subsidiaries, neither the Department nor any intervenor would be able to independently verify the Company's calculations or evaluate whether the Company's proposed allocators are based on cost causation principles. Moreover, the absence of written policies and procedures leaves Southern Union's cost allocation process vulnerable to error or a result-driven outcome.

Based on the foregoing analysis, the Department directs NEGC to prepare and maintain a detailed cost allocation manual that clearly identifies all of its cost allocation methods, policies and procedures. This cost allocation manual should (1) clearly identify which of Southern Union's divisions and subsidiaries are covered, (2) provide a complete explanation of how each cost allocation factor is determined, and (3) specify those costs to which each of these factors is applied. The cost allocation manual should also clearly describe any division- or subsidiary-specific modification to the cost allocation process, such as for those currently relating to Citrus and PEPL. The Company is directed to submit this cost allocation manual to the Department and all parties in this proceeding no later than four months from the issuance date of this Order and, thereafter, whenever revised.

e. Conclusion

The Department has approved a total management support expense of $1,176,857, consisting of $871,026 in JCC and $305,327 in allocations from Missouri Gas. The Company has proposed a total management support expense of $1,253,596, consisting of $947,343 in JCC and $306,263 in allocations from Missouri Gas. The Company's test year management support expense was $2,018,346, which includes $434,212 in management and support fees and $289,475 in royalty and licensing fees that NEGC proposed to removed from its cost of service. Therefore, the Department finds that the reduction to the Company's test year cost of service is $841,983. The Company proposes an overall reduction to test year cost of service of $764,750. Accordingly, the Department will reduce the Company's proposed cost of service by an additional $77,233.

H. Professional Fees

1. Introduction

During the test year, NEGC booked $717,946 in professional fees expense (Exhs. NEGC-JMS-2, Sch. G-13; NEGC-JMS-3, WP G-13.1).[139] NEGC proposes to increase its test year professional fees expense by $45,057 for an adjusted test year amount of $763,003 (Exhs. NEGC-JMS-2, Sch. G-13 (Rev.)). No intervenor commented on NEGC's proposed adjustments.[140]

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139 The Company charged $1,200,911 as professional fees in the test year, but removed $33,260 in legal fees related to the union contract renegotiation and $449,705 in self-insured deductible expenses for engineering and legal services primarily related to a gas explosion incident in Somerset, Massachusetts (Exhs. NEGC-JMS-1, at 26; NEGC-JMS-2, Sch. G-16 (Rev.); NEGC-JMS-2, Sch. G-18 (Rev.); NEGC-JMS-3, WP G-13.1; Tr. 3, at 368-370).

140 The proposed adjustments include: (1) an increase of $157,060 in test year professional fees expense to reflect the reversal of out-of-period accruals (Exhs. NEGC-JMS-1, at 26; NEGC-JMS-3, WP G-13.1; AG-NEGC-19-35; Tr. 3, at 370-375); (2) the inclusion of $9,617 in actuarial fees that were excluded from the original calculation of test year professional fees expense (Exh. NEGC-JMS-2, Sch. G-13 (Rev.); Tr. 3, at 389-393); and (3) the removal of $121,620 in professional fees related to legislative advocacy, amounts recoverable through the residential conservation surcharge and conservation clause factors, and a prorated portion of actuarial fees applicable to NEG Appliance and PEI Power Corporation, whose employees are covered under NEGC's pension and PBOP plans (Exhs. NEGC-JMS-1, at 26; NEGC-JMS-3, WP G-13.1; Tr. 3, at 376-379, 389-391).

2. Analysis and Findings

The Department allows a company to recover professional service or consulting fees that were booked during the test year if the fees are reasonable and if the services provide value to the company. D.T.E. 03-40, at 148, 153; D.T.E. 01-56, at 69; D.T.E. 98-51, at 47; D.P.U. 92-210, at 51-52. The Department reviews whether the specific charges incurred were reasonable, which entails an examination of matters such as the nature of the services performed, the hourly charges, and the cost of auxiliary services (including overhead and out-of-pocket expenses such as travel). D.P.U. 89-114/90-331/91-80 (Phase One) at 44. The Department next determines whether the utility has a reasonable process in place for an on-going evaluation of the cost-effectiveness of the services provided. D.P.U. 89-114/90-331/91-80 (Phase One) at 44-45. Finally, the Department reviews whether the Company obtained the service through a competitive bid. For those outside services that were not competitively bid, the company should be prepared to justify why competitive bidding was not used and why its choice of service provider was reasonable and effective. D.P.U. 93-60, at 233; D.P.U. 92-250, at 128-129.

NEGC claims a professional fees expense of $763,003. The Company has provided invoices in support of its professional fees expense (Exh. DPU-NEGC-1-15, Att.). A review of the invoices, however, supports only $738,705 in professional expense. Specifically, the acceptable invoices from Dively & Associates ($147,524), Barton Law Office ($10,454), and Keegan Werlin ($229,931) amount to less than the $400,394 reported by the Company for these three providers (Exhs. NEGC-JMS-3, WP G-13.1; DPU-NEGC-1-15, Att.). Further, the Department finds that the invoices from Donnelly & Panaggio totaling $2,196 are so heavily redacted that we are unable to confirm that the work was performed on behalf of NEGC (Exh. DPU-NEGC-1-15, Att.). In addition, the Company failed to provide any invoices to support the inclusion of $9,617 in fees associated with McConnell and Jones' actuarial services.

The professional fee invoices accepted by the Department for approval are typically broken down by the nature of services performed, the hourly charges, and the cost of auxiliary services (see Exh. DPU-NEGC-1-15, Att.). We find that the services rendered by the various providers are those customarily required for regulated gas utilities (see Exh. DPU-NEGC-1-15, Att.). Further, we are satisfied that the hourly charges for these services and the cost of auxiliary services are reasonable and consistent with services of this nature. Thus, we find the Company's expense level to be reasonable. Moreover, we find that the services provided value to the Company in its performance of its regulatory responsibilities and requirements.

While NEGC concedes that it does not have an ongoing evaluation process for the cost-effectiveness of the services provided, the Company does consider the periodic rebidding of long-term engagements with particular vendors in response to pricing increases, performance issues, and to determine whether other vendors may offer added value or pricing advantages (Exhs. DPU-NEGC-1-16, at 1; DPU-NEGC-1-18; Tr. 2, at 277). Further, the Company attempts to forecast and anticipate legal expenses at the beginning of each year, and strives to hold expenses to budgeted levels (Tr. 2, at 314). Thus, we find that there is a reasonable process in place for evaluating the services provided.

Finally, NEGC did not issue RFPs for the services provided in the test year by the non-legal and legal vendors (Exh. DPU-NEGC-1-16; Tr. 2, at 276-277). The Department, however, recognizes that an outside firm's long-term relationship and institutional experience with a company can, in certain circumstances, justify a lack of competitive bidding in securing such professional services. D.T.E. 05-27, at 241; D.T.E. 03-40, at 148-149; D.T.E. 02-24/25, at 192-193; D.T.E. 01-56, at 76.

In this regard, the record reveals that the Company relies on long-term relationships with several of its non-legal vendors whose services tend not to dramatically change in scope or price from year to year (Exh. DPU-NEGC-1-16, at 1, 2; Tr. 2, at 276-277). Further, the Company originally retained at least three of the Company's non-legal vendors through an RFP process conducted within the past three to four years (Exhs. DPU-NEGC-1-16; DPU-NEGC-1-17; Tr. 2, at 276-278). Similarly, NEGC relies on established relationships with several of its legal service providers, and seeks to contain costs by not conducting RFPs for every routine legal matter (Exh. DPU-NEGC-1-16, at 1; Tr. 2, at 279-282, 303-304, 310-313). Therefore, the Department finds that the prior institutional relationships and expertise provided by NEGC's professional consultants satisfy the competitive bidding requirement in this instance. D.P.U. 08-35, at 117; D.T.E. 05-27, at 241. Going forward, we expect that NEGC will continue to evaluate its relationships with its non-legal and legal vendors and will issue RFPs and seek re-bids where appropriate. The Company is under a continuing obligation to contain costs and, as such, must be prepared to demonstrate the propriety of the selection of its professional service providers or risk disallowance of expenses associated with those vendors.

Based on the above analysis, the Department will allow $738,705 as an annual level of professional fees expense. Accordingly, the Company's proposed cost of service will be reduced by $24,298.

I. Union Contract Negotiation and Strike Contingency

1. Introduction

During the test year, NEGC booked $33,260 in union contract negotiations and strike contingency expense (Exhs. NEGC-JMS-2, Sch. G-16 (Rev.); NEGC-JMS-3, WP G-16.2). NEGC began contract negotiations with its union during the test year, which concluded with a new contract that took effect on May 1, 2010 (Exhs. NEGC-JMS-1, at 27; AG-1-42, Att. B at 7; Tr. 3, at 398-408; Tr. 5, at 668-679). As a result of these contract negotiations, NEGC incurred $255,637 in union contract negotiation costs and $15,378 in strike contingency costs, for a total expense of $271,015 (Exh. NEGC-JMS-2, Sch. G-16 (Rev.); RR-DPU-32 Supp., Att. A at 5). Of the $255,637 in union contract negotiation costs, $18,665 represented expense incurred during the test year, and $236,972 was incurred in 2010 (Exh. NEGC-JMS-3, WP G-16.2; RR-DPU-32, Att.; RR-DPU-32 Supp., Att. A). Of the $15,378 in strike contingency costs, $783 represented expenses incurred during the test year and the remaining $14,595 represented the amortization of NEGC's strike contingency expense associated with its previous union contract that took effect May 1, 2006 (Exhs. NEGC-JMS-3, WP G-16.2; AG-1-42, Att. A).

The Company states that union contract negotiation costs include: (1) legal and consulting costs; (2) amounts paid to union representatives during their participation in negotiations; (3) rental of off-site meeting rooms for contract negotiators; and (4) bonuses paid to union employees upon completion of the contract negotiations pursuant to the final approved contract (Exhs. NEGC-JMS-3, WP G-16.1; AG-19-34; Tr. 3, at 399-403; Tr. 8, at 1019; RR-DPU-32; RR-DPU-32 Supp. Att. A). NEGC states that strike contingency costs included: (1) measures taken to protect critical distribution system valves; (2) locking gas caps for vehicles; (3) padlocks and key locks for protecting distribution infrastructure; and (4) retention of security guards (Exh. NEGC-JMS-3, WP G-16.1; Tr. 3, at 398-403; Tr. 8, at 1019; RR-DPU-32, Att.; RR-DPU-32 Supp. Atts. A through D).

The Company proposes to normalize these costs over three years consistent with the three-year term of the union contract (Exhs. NEGC-JMS-1, at 27; NEGC-JMS-2, Sch. G-16 (Rev.); Tr. 3, at 402). The Company's proposed normalization results in an annual cost of $90,338, and, thus, NEGC proposes to increase its test year cost of service by $57,078 (Exh. NEGC-JMS-2, Sch. G-16 (Rev.); Tr. 3, at 402).

2. Positions of the Parties

NEGC argues that the Department has permitted recovery of strike contingency costs as recurring reasonable costs that are necessary to ensure continued operation in a safe and reliable manner in the event that a new contract cannot be ratified (Company Brief at 22-23, citing D.T.E. 01-56, at 64). Thus, the Company maintains that it appropriately normalized both its costs associated with negotiating its union contract and its strike preparation costs (Company Brief at 23). No other party commented on this matter on brief.

3. Analysis and Findings

a. Standard of Review

The Department has denied companies' recovery of expenses incurred as a result of strikes on the grounds that they are non-recurring in nature. D.P.U. 93-60, at 136-137; D.P.U. 1350, at 90; Cambridge Electric Light Company, D.P.U. 1015, at 21 (1982). Nonetheless, the Department has found that preparation for a potential labor strike is essential to ensure that a company is able to continue to operate in the event of a strike. D.P.U. 08-35, at 159; D.T.E. 03-40, at 177; D.T.E. 01-56, at 65. Moreover, the Department has determined that a company may need to update or develop new strike contingency plans each time it negotiates a labor contract. D.P.U. 08-35, at 159; D.T.E. 03-40, at 177; D.T.E. 01-56, at 65-66.

Union contract negotiations are integral to the collective bargaining process. Nantucket Electric Company, D.P.U. 1530, at 30-31 (1983). Therefore, it is appropriate to treat them in the same manner as strike contingency costs. For both strike contingency costs and union contract negotiation costs, the Department typically normalizes such costs over the length of the union contract in question so that a representative amount is included in the utility's cost of service. D.T.E. 03-40, at 177-178; D.T.E. 01-56, at 66; D.P.U. 1530, at 31.

b. Union Contract Negotiation Expense

NEGC was engaged in contract negotiations during the test year and regularly participates in collective bargaining in order to arrive at union contracts. Thus, the Department finds that the union contract negotiation activities in this instance are recurring. See D.T.E. 01-56, at 65-66. Having found that union contract negotiation activities are recurring, the Department must determine whether the Company has demonstrated the reasonableness of the incurred costs. D.P.U. 10-55, at 310-311.

The Company has proposed to include in cost of service $68,000 in one-time bonuses that were paid to union employees upon the ratification of the union contract (RR-DPU-32 Supp., Att. A at 3-4). NEGC claims that this practice is "one, maybe two contracts old, so it was something that the union was clearly looking for . . . in order to secure their acceptance of the new contract" (Tr. 5, at 671-672). While such payments may not be unusual in the collective bargaining process, the fact that such payments were made does not necessarily mean that similar payments will be negotiated as part of future collective bargaining efforts. Different circumstances may be present three years from now that could result in a different outcome. Consequently, we find that these costs are not periodically recurring. Accordingly, we will remove the bonuses of $68,000 from the recoverable level of union negotiation expense.

The Company has provided supporting documentation for the remaining $187,637 in union contract negotiation costs (RR-AG-18; RR-DPU-32 Supp., Atts. A through D). Based on our review of this information, the Department finds that the $187,637 in union contract negotiation costs are reasonable. Accordingly, we will include these expenses in the recoverable level of union contract negotiation costs.

c. Strike Contingency Expense

As noted above, NEGC was engaged in contract negotiations during the test year, and regularly engages in collective bargaining to negotiate every union contract. Therefore, the Department finds that the strike contingency costs incurred during the test year are in this instance are recurring. See D.T.E. 01-56, at 65-66. Having found that those costs are recurring, the Department must determine whether the Company has demonstrated the reasonableness of the incurred costs. D.P.U. 10-55, at 310-311.

The strike contingency expenses incurred during the test year consist of security measures taken to ensure the continuation of safe operations (e.g., securing protect critical distribution system valves, and arranging for security guards) (RR-DPU-32 Supp., Att. A). As part of its public service obligation, it is critical that the Company be able to continue operating in the event of a strike. D.P.U. 08-35, at 159; D.T.E. 03-40, at 177; D.T.E. 01-56, at 65. Thus, the Department finds the Company's strike contingency expenses incurred during the test year to be reasonable. NEGC, however, also proposes to include in its strike contingency costs $14,595 that it states is the remaining amortization associated with its previous union contract (Exh. NEGC-JMS-1, at 27). We recently reiterated our policy that in granting recovery of strike contingency costs, we do not guarantee full recovery of the costs. D.P.U. 10-55, at 312. Instead, we normalize the costs so that a representative amount is included in the utility's cost of service. D.P.U. 10-55, at 312. Accordingly, the Department disallows recovery of the $14,595 in costs related to its prior union contract and allows the amount of $783 in the Company's cost of service for strike contingency expenses.

d. Normalization

The Department typically normalizes union contract negotiation and strike contingency costs over the length of the union contract in question so that a representative amount is included in the utility's cost of service. D.T.E. 03-40, at 177-178; D.T.E. 01-56, at 66; D.P.U. 1350, at 90. In this case, we find that NEGC has appropriately proposed to normalize its strike contingency costs and union contract negotiation costs over a period equal to the length of the contract, i.e., three years. Thus, we approve the Company's proposed normalization period.

e. Conclusion

Based on the foregoing analysis, the Department has included in NEGC's cost of service $783 in strike contingency costs and $187,637 in union contract negotiation costs, for a total of $188,420. Normalization of these costs over three years results in an annual expense of $62,807. Accordingly, the Company's proposed cost of service will be reduced by $27,531.

J. Rate Case Expense

1. Introduction

In its initial filing, NEGC estimated that it would incur $985,519 in rate case expense associated with this rate case (Exhs. NEGC-JMS-2, Sch. G-19). NEGC's proposed rate case expenses includes expert services related to: (1) legal representation; (2) cost of capital analysis; (3) cost of service analysis; and the (4) decoupling and TIRF proposals, updated marginal cost study, allocated cost study, and rate design proposal[141] (Exh. NEGC-JMS-2, Sch. G-19). NEGC issued requests for proposals ("RFPs") for each of the aforementioned expert services (Exhs. DPU-NEGC-1-2; DPU-NEGC-1-3, Att.).

In addition to the rate case expense attributable to the instant matter, NEGC also seeks to recover the unamortized balance of rate case expense from the Company's last rate case, D.P.U. 08-35, which totals $701,500 (Exhs. NEGC-JMS-1, at 30, 32; NEGC-JMS-2, Sch. G-19 (Rev.)).[142] Thus, NEGC initially sought a total rate case expense of $1,687,019 (Exh. NEGC-JMS-2, Sch. G-19).

Based on its final invoices and estimated invoices to complete the compliance filing,[143] NEGC proposes a total rate case expense of $1,021,414, exclusive of the unamortized balance from D.P.U. 08-35 (Exhs. NEGC-JMS-2, Sch. G-19 (Rev.); DPU-NEGC-5-7 Supp., Att. A). Including the balance from the previous rate case, the Company seeks $1,722,914 in total rate case expense recovery (Exh. NEGC-JMS-2, Sch. G-19 (Rev.)).

NEGC submits that the total rate case expense of $1,722,914 normalized over a five-year period yields an annual expense of $344,583 (Exh. NEGC-JMS-2, Sch. G-19

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141 The Company selected one provider to perform work on all four of these issues (see Exhs. DPU-NEGC-1-3, Att. at 28-47; DPU-NEGC-1-8(A) at 3).

142 In D.P.U. 08-35, at 134, 136, the Department approved the amount of $1,126,872 for the Company's rate case expense, to be normalized over a six-year period.

143 As discussed below, NEGC provides the following estimates to complete the compliance filing: (1) $2,552 for the cost of capital analysis; (2) $10,000 for services related to the decoupling and TIRF proposals, updated marginal cost study, allocated cost study, and rate design proposal; (3) $6,000 for the cost of service analysis; and (4) $20,000 for legal services (Exh. DPU-NEGC-5-7 Supp., Att. A).

(Rev.)). Alternatively, the Company proposes that if the unamortized balance of rate case expense incurred in D.P.U. 08-35 is excluded from the calculation of overall rate case expense subject to normalization in this case, a three-year normalization should be applied to the total rate case expenses incurred in this matter (Exhs. NEGC-JMS-1, at 33; AG-22-16). Normalizing the proposed rate case expense of $1,021,414 over three years produces an annual expense of $340,471.

2. Positions of the Parties

a. Attorney General

The Attorney General raises several arguments regarding NEGC's proposed recovery of rate case expense. First, the Attorney General argues that the Department should limit the Company's recovery of rate case expense associated with the decoupling and TIRF proposals, updated marginal cost study, allocated cost study, and rate design proposal (Attorney General Brief at 81). The Attorney General contends that the costs associated with these services were unreasonably and imprudently incurred and were not adequately controlled though a competitive solicitation, in contravention of Department precedent (Attorney General Brief at 81, citing D.P.U. 07-71, at 139-140; D.T.E. 03-40, at 149, 153; D.T.E. 02-24/25, at 192; D.T.E. 98-51, at 61). In particular, the Attorney General notes that the Company failed to provide a "clear, well-documented and thorough explanation" as to why it retained the highest bidder to the RFP for these services (Attorney General Brief at 82). In this regard, the Attorney General contends that NEGC's selection process for outside service providers was not scientific, did not include a formal scoring system, and was not particularly long or laborious

(Attorney General Brief at 82, citing Tr. 2, at 252-253, 256). The Attorney General asserts that, because NEGC has failed to justify the selection of the highest bidder, the Department should at least limit rate case expense recovery for these services to the amount of the lowest bid (Attorney General Brief at 82, citing D.P.U. 09-39, at 287; D.P.U. 08-35, at 130-131).

Second, the Attorney General takes issue with NEGC's proposed recovery of rate case expense associated with its cost of service witness (Attorney General Brief at 82). The Attorney General argues that, because this provider was the only respondent to an RFP sent to four prospective bidders, and the Company did not consider soliciting additional bids from another group of prospective service providers due to time constraints, NEGC did not engage in a competitive bidding process for these services (Attorney General Brief at 82-83, citing Exhs. DPU-NEGC-1-3, Att.; DPU-NEGC-1-5; Tr. 2, at 264). The Attorney General contends, therefore, that the Company had no objective benchmark against which to measure the prudence of the selection of this bidder (Attorney General Brief at 83). Further, the Attorney General rejects any notion that this provider possesses a unique, institutional knowledge of the Company, sufficient to warrant an exception to the Department's requirement of a competitive solicitation (Attorney General Brief at 84). For these reasons, the Attorney General asserts that the Department should disallow the rate case expense associated with this service provider (Attorney General Brief at 84).

Third, the Attorney General argues that the Department should limit the amount of recoverable rate case expense associated with legal services because retained counsel was not the most cost-effective bidder (Attorney General Brief at 84). The Attorney General contends that the Company rejected an aggressively discounted (and lowest overall) bid and instead selected the highest bidder of the three respondents to the RFP because of time constraints and the ability of the highest bidder to "ramp-up" for litigation (Attorney General Brief at 84, citing Tr. 2, at 265). The Attorney General claims that the aforementioned rejected bidder has extensive experience before the Department and expertise in rate cases (Attorney General Brief at 84-85, citing Exh. DPU-NEGC-1-4, Att. at 125-129). Further, the Attorney General notes that NEGC pre-selected its legal counsel before the issuance of the RFP, and would retain another bidder only if there was a compelling reason to do so (Attorney General Brief at 85, citing Exh. DPU-NEGC-1-5). For these reasons, the Attorney General asserts that the Department should limit the recovery of rate case expense for legal services to the amount of the lowest bid (Attorney General Brief at 85).

Finally, the Attorney General argues that the unamortized balance of rate case expense from D.P.U. 08-35 should not be included in the rate case expense allowed for recovery in this case (Attorney General Brief at 54). The Attorney General contends that the purpose of including the normalized rate case expense in the cost of service is not to guarantee a dollar-for-dollar recovery of rate case expense (Attorney General Brief at 54, citing Exh. AG-DJE-1, at 6-7). Further, the Attorney General asserts that the circumstances of this case are not unique, and NEGC has not demonstrated why it should be treated differently from other utilities that come before the Department (Attorney General Reply Brief at 9).

According to the Attorney General, the issue is one of symmetry (Attorney General Brief at 55; Attorney General Reply Brief at 9-10). The Attorney General argues that, because there is no refund to customers in situations where the period between rate cases is longer than expected and rates still reflect recovery of rate case expense after those costs have been fully amortized, there should be no recovery of unamortized rate case expense where the period between rate cases is shorter than expected (Attorney General Brief at 54-55, citing Exh. AG-DJE-1, at 6-7).[144] Moreover, the Attorney General rejects the Company's assertion that denial of the unamortized balance from D.P.U. 08-35 would result in financial harm to the Company (Attorney General Reply Brief at 10-11). The Attorney General argues that the approval or denial of this expense will not impact achievement of the authorized rate of return differently from the approval or denial of any other adjustment proposed by the Company (Attorney General Reply Brief at 10-11).

In sum, the Attorney General argues that NEGC's rate case expense should be normalized in accordance with Department precedent so that a representative annual amount of rate case expense, and not dollar-for-dollar recovery, is included in NEGC's cost of service (Attorney General Brief at 55, citing D.P.U. 10-55, at 339; D.P.U. 09-39, at 295-296; D.P.U. 09-30, at 241; D.PU. 08-35, at 135; D.P.U. 08-27, at 75-76. In this regard, the Attorney General maintains that the Department should reject NEGC's request for a three-year normalization period if the unamortized balance of rate case expense from D.P.U. 08-35 is

[144] In particular, the Attorney General notes that NEGC did not propose to credit customers with any over-recovery of rate case expense that occurred during the eleven-year interim between the Company's rate cases in D.P.U. 96-60 and D.T.E. 07-46 (Attorney General Reply Brief at 10). As such, the Attorney General asserts that the Company should not be able to prospectively recover rate case costs from D.P.U. 08-35 (Attorney General Brief at 54-55; Attorney General Reply Brief at 10).

excluded from recovery (Attorney General Brief at 56, citing Exh. AG-DJE-1, at 8; D.P.U. 09-30, at 242; 08-27, at 76-77).

b. Company

NEGC argues that it has met the Department's standard with respect to rate case expenses incurred in this case, as it engaged in a competitive bidding process for all its outside rate case consultants (Company Reply Brief at 11, citing Exh. DPU-NEGC-1-5). With respect to NEGC's cost of service consultant, the Company contends that there was adequate time for all four bidders to submit a response to the RFP, but only the retained consultant decided to bid (Company Reply Brief at 11, citing Exhs. DPU-NEGC-1-3, Att.; DPU-NEGC-1-5).

Further, NEGC argues that where it did not select the lowest bidder, it nevertheless satisfied Department precedent by conducting a structured, objective competitive bidding process and choosing the bidders that would provide services at a reasonable cost based on their experience, knowledge of the Company, and ability to efficiently support the Company in this case (Company Reply Brief at 11-12, citing Exh. DPU-NEGC-1-3, Att.; D.T.E. 03-40, at 153). The Company contends that, based on these criteria, its selection of its consultant for services related to the decoupling and TIRF proposals, updated marginal cost study, allocated cost study, and rate design proposal, as well as its retention of legal counsel, was appropriate (Company Reply Brief at 11-13, citing Exhs. DPU-NEGC-1-5; DPU-NEGC-5-7 Supp.).

NEGC rejects the Attorney General's assertion that the Company's normalization proposal is asymmetrical (Company Reply Brief at 11, citing Attorney General Brief at 54-56, 81-85; Attorney General Reply Brief at 9-11).[145] NEGC concedes that its normalization proposal to include the unamortized balance of rate case expense from D.P.U. 08-35 is a departure from Department precedent, but the Company argues that these unamortized expenses are "real costs" that the Company incurred to maintain its financial integrity (Company Brief at 31). NEGC claims that a write-off of these expenses, which total $701,500, is "very significant and represents nearly 26 percent of adjusted net income" (Company Brief at 25, 32, citing Exh. NEGC-JMS-1, at 28).

Further, NEGC argues that the Department's normalization precedent is premised on the assumption that the historical average time span between rate cases is normal and representative of the expected time span in the future (Company Brief at 24, 31, citing Exh. NEGC-JMS-1, at 26-27). The Company contends that the time span between the instant matter and its last several rate cases has not achieved a result that is consistent with this assumption (Company Brief at 24; Company Reply Brief at 14).[146] Thus, NEGC claims that

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145 In particular, NEGC rejects the Attorney General's assertion that that the Company has been over-recovering the rate case expense it incurred in D.P.U. 96-60 (Company Reply Brief at 13, citing Attorney General's Reply Brief at 10). The Company argues that its annual returns filed with the Department over the past decade demonstrate the financial distress the Company has faced, including in the time period covered by D.P.U. 96-60 where the Company was vastly under-earning for several years (Company Reply Brief at 13, citing Exhs. AG-NEGC-1-12; AG-NEGC-7-9; AG-NEGC-12-28-A; AG-NEGC-12-28-B).

146 NEGC notes that it has only been 2.17 years since its last rate case, D.P.U. 08-35, which in turn was filed 1.10 years from the previous case, D.P.U. 07-46 (Company Brief at 24). The Company states that, prior to D.P.U. 07-46, it had been slightly over eleven years since it had filed for a rate increase, during which time its customers experienced the benefit of having no increase in their base rates (Company Brief at 24, citing Exh. NEGC-JMS-1, at 27).

applying the Department's traditional methodology in the current case yields a five-year normalized time span, which is not representative of the Company's actual experience or expected ongoing rate case activity (Company Brief at 25, citing Exh. NEGC-JMS-1, at 29). The Company contends that its proposal will result in a reasonable normalized level of rate case expense and will allow the Company to avoid the financial harm that will occur if it cannot recover the unamortized balance from D.P.U. 08-35 (Company Brief at 25, citing Exh. NEGC-JMS-1, at 30; Company Reply Brief at 14). Conversely, NEGC asserts that a stringent adherence to Department precedent in this case will prevent the Company from achieving its authorized rate of return during the first twelve months for which rates are in effect, and will be "self-defeating" in terms of attempting to structure adequate rate recovery to avoid frequent rate cases (Company Brief at 26, 31-32).

NEGC also argues that another option available to the Department is to allow the costs to be amortized and recovered through a reconciling factor (Company Reply Brief at 14). The Company asserts that this approach would achieve the objectives of the Department's historical normalization methodology in circumstances in which its historical methodology produces an unfair and abnormal level of ongoing annual cost (Company Reply Brief at 14-15).

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. D.P.U. 07-71, at 99;

D.T.E. 05-27, at 157; D.T.E. 98-51, at 61-62.[147] Second, such expenses must be reasonable, appropriate, and prudently incurred. D.P.U. 09-30, at 227; D.T.E. 98-51, at 58; D.P.U. 95-118, at 115-119; D.P.U. 84-32, at 14.

The overall level of rate case expense among utilities has been, and remains, a matter of concern for the Department. D.P.U. 07-71, at 99; D.T.E. 03-40, at 147; D.T.E. 02-24/25, at 192; D.P.U. 93-60, at 145. Rate case expense, like any other expenditure, is an area where companies must seek to contain costs. D.P.U. 07-71, at 99; D.T.E. 03-40, at 147-148; D.T.E. 02-24/25, at 192; D.P.U. 96-50 (Phase I) at 79. All companies are on notice that the risk of non-recovery of rate expense 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. 09-39, at 290-293; D.P.U. 09-30, at 238-239; D.T.E. 03-40, at 153. Further, the Department has found that rate case expenses will not be allowed in cost of service where such expenses are disproportionate to the relief being sought. See Barnstable Water Company, D.P.U. 93-223-B at 16 (1993). Moreover, in its continuing scrutiny of the overall level of rate case expense, the Department may require shareholders to shoulder a portion of the expense. D.P.U. 08-35, at 135.

[147] While petitioners may seek recovery of rate case expense incurred on a fixed-fee basis for work performed after the close of the evidentiary record (e.g., for completion of necessary compliance filings), the reasonableness of the fixed fees must be supported by sufficient evidence. D.T.E. 02-24/25, at 196.

b. Competitive Bidding

i. Introduction

The Department has consistently emphasized the importance of competitive bidding for outside services in a petitioner's overall strategy to contain rate case expense. See, e.g., D.T.E. 05-27, at 158-159; D.T.E. 03-40, at 148; D.T.E. 02-24/25, at 192. If a petitioner elects to secure outside services for rate case expense, it must engage in a competitive bidding process for these services. D.P.U. 07-71, at 99-100, 101; D.T.E. 03-40, at 153.

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

The Department does not seek to substitute its judgment for that of a petitioner in determining which consultant may be best suited to serve the petitioner's interests, and obtaining competitive bids does not mean that a company must necessarily retain the services of the lowest bidder regardless of its qualifications. D.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.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.T.E. 03-40, at 153.

The Attorney General questions the solicitation process undertaken for services related to the: (1) decoupling and TIRF proposals, updated marginal cost study, allocated cost study, and rate design proposal; and (2) cost of service analysis. Neither the Attorney General nor any other party questions the competitive solicitation process for the remaining rate case services. The Attorney General, however, challenges the cost-effectiveness of the legal counsel selected. Given the importance of a competitive solicitation process in containing rate case expense, the Department first will evaluate the Company's RFP process used to solicit bids for all of the non-legal and legal consultants in this case, and then we will address the Company's selection of each of its consultants.

ii. The RFP Process

The record demonstrates that by mid-January 2010, NEGC was prepared to file the instant rate case and began to assemble the necessary materials to begin the RFP process (Tr. 2, at 272-273). By early February 2010, NEGC had issued RFPs for the services rendered by each expert or consultant in this case, including legal services (Exhs. DPU-NEGC-1-2; DPU-NEGC-1-3, Att.).[148] The RFPs followed the same general form used in the Company's last rate case, D.P.U. 08-35, and were modified to meet the specific needs of the instant case (Tr. 2, at 249). Each RFP contained a description of the scope of work and the criteria upon which each bidder would be evaluated (Exh. DPU-NEGC-1-3, Att.). The Company selected the potential bidder pool based in part on familiarity with certain consultants, and following internal discussions and additional research regarding the field of experts who had testified before the Department in recent rate cases (Tr. 2, at 249-250). NEGC solicited a number of experienced prospective bidders for each of the aforementioned non-legal and legal services (See Exh. DPU-NEGC-1-2; DPU-NEGC-1-3, Att.).

NEGC did not use a formal selection process to evaluate, score, and select a winning bid, though it was prepared to do so if the bids proved to be more competitive (Tr. 2, at 252). Instead, in selecting its consultants, the Company relied on internal discussions and deliberation among the chief operating officer of Southern Union and the chief operating officer of NEGC (Tr. 2, at 249-250). These officials evaluated the reasonableness of each

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[148] It is somewhat unclear when the RFP for legal services was issued, as the first page of each RFP related to legal services is dated January 8, 2010, while the remaining pages are dated February 8, 2010 (Exh. DPU-NEGC-1-3, Att. at 13-27).

RFP, and gave particular weight to the capability of the bidders and the estimated costs submitted in response to the RFPs (Tr. 2, at 251-252). The Company, however, maintains that each evaluation criteria set forth in the RFPs was considered in assessing the bids (Tr. 2, at 252).

Based on the foregoing, the Department finds that the Company conducted a fair, open, and transparent RFP process to generate bids from potential non-legal and legal consultants necessary for completion of this rate case. While the Company admittedly conducted the RFP process under a compressed timeframe, the Department is satisfied that, in this case, the timeframe did not compromise the pool of prospective bidders or have any adverse effect on the quality of the bids received by the Company. Further, we conclude that NEGC's bid evaluation process was adequately structured to allow the Company to determine the capabilities, approach, and pricing offered by the various service providers. Specifically, we determine that the Company's informal scoring system was sufficient to provide an objective benchmark to measure the reasonableness of the costs of the various services. We shall address the prudency and cost-effectiveness of the Company's decision to select particular consultants below.

c. Company's Rate Case Consultants

i. Cost of Capital Services

Neither the Attorney General nor any other party challenges the retention of the cost of capital consultant in this matter. Nevertheless, the Company still has the burden to demonstrate that its selection of this service provider was prudent and appropriate. D.T.E. 98-51, at 58; D.P.U. 95-118, at 115-119; D.P.U. 84-32, at 14.

The record shows that NEGC issued an RFP to four potential cost of capital consultants and received two responses (Exhs. DPU-NEGC-1-2; DPU-NEGC-1-3, Att. at 1-12; DPU-NEGC-1-4, Att. at 1-48; DPU-NEGC-1-5, at 1). The RFP clearly set forth the scope of work to be performed and the criteria upon which each bidder would be evaluated (Exh. DPU-NEGC-1-3, Att.). NEGC selected a consultant who provided the same type of services for the Company in its last rate case, D.P.U. 08-35 (Exh. DPU-NEGC-1-5, at 1). NEGC, therefore, was familiar with the consultant's performance and, in turn, the consultant was familiar with the Company's operations (See Exh. DPU-NEGC-1-5, at 1). Conversely, NEGC had not previously worked with the particular individual consultants proposed by the rejected bidder, and the Company had no previous experience with this bidder's work on capital structure or rate of return issues (Exh. DPU-NEGC-1-5, at 1).

Regarding cost containment with respect to NEGC's cost of capital consultant, the record demonstrates that the selected consultant offered a not-to-exceed lump sum for filing preparation work, and its overall estimate of costs was commensurate with the actual costs incurred by the Company for these services in D.P.U. 08-35 (Exhs. DPU-NEGC-1-4, at 28, 32; DPU-NEGC-1-5). Further, the estimate was significantly less than that submitted by the other bidder for the same services in the instant case (Exhs. DPU-NEGC-1-4, at 9; DPU-NEGC-1-5). Moreover, the total costs ultimately charged by this consultant in the instant case, exclusive of estimated costs for compliance work, were less than the estimated costs (Exh. DPU-NEGC-5-7 Supp., Att. A).

The Department finds that NEGC's prior relationship with the winning bidder, the bidder's familiarity with the Company's operations, and the Company's lack of experience with the rejected bidder, combined to render the selection of the retained bidder a logical choice. Further, we are satisfied that the Company took appropriate steps to contain costs related to the bidder's services by accepting a bid that included a not-to-exceed lump sum for a portion of the work and was reflective of the actual costs of the same type of work previously performed in NEGC's last rate case. Moreover, the total costs associated with this provider were not unreasonable or disproportionate to the work provided. Based on these considerations, we conclude that the Company's selection of the retained bidder was reasonable and appropriate and the costs associated with this provider were prudently incurred.

ii. Rate Design, Decoupling, TIRF, and Allocated Cost of Service Study

As set forth above in Section V.J.2., the Attorney General argues that the costs associated with the services for rate design, decoupling, TIRF, and the allocated cost of service study were unreasonably and imprudently incurred and were not adequately controlled though a competitive solicitation (Attorney General Brief at 81-82). Further, the Attorney General contends that the Company failed to justify the selection of the highest bidder to the Company's RFP for these services (Attorney General Brief at 82, citing, e.g., D.P.U. 09-39, at 287; D.P.U. 08-35, at 130-131). For these reasons, the Attorney General proposes that the

Department should at least limit rate case expense recovery for these services to the amount of the lowest bid (Attorney General Brief at 82).

The Company has the burden of demonstrating that its selection of this service provider was prudent and appropriate. D.P.U. 09-39, at 287; D.T.E. 05-27, at 158-159; D.T.E. 98-51, at 59-61. This burden is especially great where the Company did not choose the lowest bidder, and the best evidence to aid the Company in satisfying its burden is contemporaneous documentation of its well-analyzed decision making. D.P.U. 08-35, at 130-131; D.T.E. 03-40, at 83-84, 153.

The record shows that NEGC issued an RFP to five potential service providers and received two responses (Exhs. DPU-NEGC-1-2; DPU-NEGC-1-3, Att. at 28-47; DPU-NEGC-1-4, Att. at 138-177; DPU-NEGC-1-5, at 1-2; Tr. 2, at 257). NEGC retained the higher of the two bidders (Exh. DPU-NEGC-1-5, at 1-2). As noted above in Section V.J.3.b., NEGC did not use a formal evaluation process or scoring system to rank the bids (Tr. 2, at 252). The record demonstrates, however, that the Company gave careful consideration to price and non-price factors before selecting the provider that it believed would provide the best combination of price and quality of service (Exh. DPU-NEGC-1-5, at 1-2; Tr. 2, at 273-275). In this regard, the Company considered that the retained bidder is experienced, has presented before the Department on numerous occasions, and has provided specific marginal and allocated cost studies and rate design services to the Company in its last two rate cases (Exhs. DPU-NEGC-1-4, Att. at 141; DPU-NEGC-1-5, at 2). Further, the bidder provided a comprehensive bid response that included a detailed scope of work and a breakdown of costs attributable to the services sought by the RFP (Exh. DPU-NEGC-1-4, Att. at 139-156).[149]

Conversely, NEGC was unfamiliar with the rejected bidder's work product quality, standards, and efficiency, and the Company was concerned that this bidder substantially underestimated the time required to support discovery, hearing, and other post-filing processes (Exh. DPU-NEGC-1-5, at 2). Such concerns are reasonable given that a review of this bidder's RFP response reveals that it is not as comprehensive as the selected consultant and is focused almost solely on the proposed decoupling mechanism and TIRF, but not on the updated marginal cost study, allocated cost study, or rate design analysis sought by the RFP (Exh. DPU-NEGC-1-4, Att. at 167-171).

Further, although the selected service provider did not provide the lowest bid, it did offer a not-to-exceed lump sum for filing preparation work and a blended hourly rate for a project team of five or more members (Exh. DPU-NEGC-1-5, at 1-2). Conversely, as noted above, the bid provided by the rejected bidder included only work related to the proposed decoupling and TIRF mechanism, with a cost estimate that was nearly half that provided by the retained bidder (Exh. DPU-NEGC-1-4, Att. at 154, 171; DPU-NEGC-1-5, at 1-2; Tr. 2, at 273-274). Thus, had the rejected bidder provided a comprehensive bid, it is reasonable to

149 While neither the RFP nor this bidder's response expressly discusses the proposed TIRF, both reference a proposed capital tracking mechanism similar to that approved by the Department in D.P.U. 09-30 (Exhs. DPU-NEGC-1-3, Att. at 28; DPU-NEGC-1-4, Att. at 149; RR-DPU-19). The Department finds, therefore, that the RFP adequately sought bids for the proposed TIRF, and the bidder's response includes an estimate for this work (see RR-DPU-19).

expect that the estimated cost difference between the two bids would have significantly diminished. Moreover, we find that, when considering the overall scope of work to be provided by the selected consultant, the total expenses associated with this service provider are proportional to the services provided, and comparable to those charged by this consultant for similar work provided in the Company's last two rate cases (Exhs. DPU-NEGC-1-4, at 154; DPU-NEGC-1-5, at 1-2; DPU-NEGC-5-7 Supp., Att. A).

Based on these considerations, we conclude that NEGC has demonstrated that it carefully evaluated both price and non-price factors, and selected a service provider who possesses expertise and experience, knowledge of Department ratemaking precedent, familiarity with NEGC's operations, and a comprehensive understanding of the tasks for which it was requested to bid (Exhs. DPU-NEGC-1-4, Att. at 140-154; DPU-NEGC-1-5, at 2; Tr. 2, at 273-275). Further, the Company has demonstrated adequate cost-control features associated with this consultant's services, and the total costs associated with this service provider were not unreasonable or disproportionate to the overall scope of work provided (Exhs. DPU-NEGC-1-4, at 154; DPU-NEGC-1-5, at 2; DPU-NEGC-5-7 Supp., Att. A). As such, we conclude that the Company's selection of the retained bidder was reasonable and appropriate and that the costs associated with this provider were prudently incurred.[150]

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[150] NEGC states that it considered issuing separate RFPs for the decoupling and TIRF services, but determined it was more cost effective to group these services together with the marginal and allocated cost studies and rate design (Exh. DPU-NEGC-5-10). The Company notes that any cost savings resulting from a comparison of hourly rates would likely have been lost given the increased time that separate consultants would need to devote to the discovery and evidentiary hearing phases of this case

iii. Cost of Service Consultant

The Attorney General argues that NEGC did not engage in a competitive bidding process for these services because the retained cost of service consultant was the only respondent to an RFP sent to four prospective bidders, and that the Company did not consider soliciting additional bids from another group of prospective service providers due to time constraints (Attorney General Brief at 82-83, citing Exhs. DPU-NEGC-1-3, Att.; DPU-NEGC-1-5; Tr. 2, at 264). Further, the Attorney General asserts that the Company had no objective benchmark to measure the prudence of the selection of this bidder, and that there is no special relationship between the provider and Company to warrant an exception to the Department's requirement of a competitive solicitation (Attorney General Brief at 83). Thus, the Attorney General asserts that the Department should disallow the rate case expense associated with this service provider (Attorney General Brief at 84).

The record shows that NEGC issued an RFP to four potential consultants and received one response (Exhs. DPU-NEGC-1-2, at 1; DPU-NEGC-1-3, Att. at 48-59; DPU-NEGC-1-4, Att. at 182-206; DPU-NEGC-1-5, at 1; Tr. 2, at 262). The retained consultant performed the same services for the Company in D.P.U. 08-35, and the Company has maintained an ongoing working relationship with this consultant for several years (Exh. DPU-NEGC-1-5, at 1). Thus, contrary to the Attorney General's assertions that there is no special relationship between the provider and Company, we determine that the consultant is conversant with the

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(Exh. DPU-NEGC-5-10). The Department is satisfied that, in the instant case, the Company's choice to group these four services together was reasonable.

Company's operations and personnel. Further, the retained consultant offered a not-to-exceed, capped bid in this case that, while higher than the estimate provided in D.P.U. 08-35, amounts to less than the actual expenses incurred in that previous rate case (Exh. DPU-NEGC-1-5, at 1; Tr. 2, at 262-264).[151] Moreover, the costs associated with this provider are not disproportionate to the services provided. Thus, we determine that it was not necessary, in this instance, for the Company to reopen its RFP process to solicit additional bids.

Based on these considerations, we find that the competitive solicitation process was adequate to establish a benchmark for the capabilities, approach, and pricing for the services sought by the RFP. Thus, we conclude that an additional competitive solicitation for these services was unnecessary and would have constituted an inefficient use of the Company's resources. For all of the above reasons, we find that the Company's selection of the retained bidder was reasonable and appropriate, and that the costs associated with this provider were prudently incurred.

iv. Legal Services

The Attorney General argues that the Department should limit the amount of recoverable rate case expense associated with legal services because the Company rejected an aggressively discounted (and lowest overall) bid from an experienced bidder, and instead selected the highest bidder of the three respondents to the RFP because of time constraints and

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[151] Given the issues presented in this case, we find that the bid provided by the consultant is not unreasonable, even assuming that the consultant would realize some efficiencies from its representation of NEGC in the prior rate case (see Tr. 4, at 552-553, 558-559).

the ability of the highest bidder to "ramp-up" for litigation (Attorney General Brief at 84-85, citing Exh. DPU-NEGC-1-4, Att. at 125-129; Tr. 2, at 265). Further, the Attorney General notes that NEGC pre-selected its legal counsel before the issuance of the RFP, and would retain another bidder only if there was a compelling reason to do so (Attorney General Brief at 85, citing Exh. DPU-NEGC-1-5). The Attorney General asserts that the Department should limit the recovery of rate case expense for legal services to the amount of the lowest bid (Attorney General Brief at 85).

NEGC concedes that its long-standing regulatory counsel was its preferred choice of legal counsel for this rate case given the firm's rate case experience and its well-developed working relationship with the Company (Exh. DPU-NEGC-1-5, at 2). Nevertheless, the Company conducted a competitive solicitation process in order to obtain the best legal counsel and representation available at the most cost-effective rate (Exh. DPU-NEGC-1-5, at 2). NEGC contends that these objectives were achieved through the RFP process, as a review of the other bidders' responses to the RFP raised doubts about their capabilities and overall costs to perform the required services (Exh. DPU-NEGC-1-5, at 2-3; Tr. 2, at 264-265).

The record shows that NEGC issued an RFP for legal services to five law firms and received three responses (Exhs. DPU-NEGC-1-2, at 2; DPU-NEGC-1-3, Att. at 13-27; DPU-1-4, Att. at 49-137; DPU-NEGC-1-5, at 2-3). The Company chose the highest bidder (Exhs. DPU-NEGC-1-4, at 49-137; DPU-NEGC-1-5, at 2-3). The Company has the burden to demonstrate that its selection of this service provider was prudent and appropriate. D.T.E. 05-27, at 158-159; D.T.E. 98-51, at 59-61. This burden is especially great where the

Company did not choose the lowest bidder, and the best evidence to aid the Company in satisfying its burden is contemporaneous documentation of its well-analyzed decision making. D.P.U. 08-35, at 130-131; D.T.E. 03-40, at 83-84, 153.

NEGC rejected one bidder because the Company was unable to ascertain from the bid a reliable estimate of overall cost (Exh. DPU-NEGC-1-5, at 2-3; Tr. 2, at 264-265). The Company determined that, unless the firm relied on its most junior attorneys billing at their lowest rates, any blended rate that could be discerned from the bid would be higher than the discounted flat rate offered by the winning bidder (Exh. DPU-NEGC-1-5, at 2-3; Tr. 2, at 264). A review of the rejected bidder's proposal validates the Company's concerns. While the RFP response identifies the various personnel expected to work on the case, and their respective rates, the bidder did not provide an estimate of the overall costs, or a blended rate for its attorneys (Exh. DPU-NEGC-1-4, Att. at 62-63). Thus, there is no way to determine the overall cost that the Company could be expected to incur from this firm's representation.

NEGC states that the lowest bidder aggressively discounted its bid, but that the Company had concerns with the firm's level of experience in rate case matters, as well as the availability of resources necessary to litigate this proceeding (Exh. DPU-NEGC-1-5, at 3; Tr. 2, at 265). A review of the record demonstrates that this provider offered a blended hourly rate for attorney work that was less than the accepted bid (Exh. DPU-NEGC-1-4, Att. at 83, 111). This firm, however, has not represented a gas or electric distribution company in a rate case since 2002, well before the introduction of decoupling mechanisms and infrastructure replacement cost recovery trackers (Exh. DPU-NEGC-1-4, Att. at 125-126).

While we do not suggest that this bidder lacks the legal skill necessary to litigate such a case, it was not unreasonable for NEGC to determine that any cost savings achieved through a lower rate could potentially be diminished by the need of the rejected bidder to devote additional time to preparing and presenting the various issues in this case.

The retained bidder is an experienced law firm, well known to the Department. It has represented gas and electric distribution companies in recent rate cases involving decoupling and capital tracking mechanisms (Exh. DPU-NEGC-1-4, Att. at 85; see also D.P.U. 10-55). Moreover, this firm represented NEGC in its last two rate cases and, therefore, is very familiar with the Company's operations and has cultivated an effective working relationship with Company personnel (Exhs. DPU-NEGC-1-4, Att. at 85; DPU-NEGC-1-5, at 3). Based on these considerations, it is understandable that this firm was the Company's preferred choice to provide legal services.

Notwithstanding the above, however, the same rules apply to the retention of legal services as non-legal consultants. That is, the Company must strive to contain costs associated with legal services. In this regard, the record demonstrates that legal counsel selected by the Company offered a fee proposal that contained cost-control features. Specifically, the retained bidder offered discounted hourly rates in the early stages of the case and a flat fee based upon a blended rate for the remainder of the proceeding (Exh. DPU-NEGC-1-4, Att. at 83; Tr. 2, at 267). The discounted rates and the flat, blended rate were not inconsequential reductions from the rates normally charged by the lead attorneys assigned to the case (Exh. DPU-NEGC-1-4, Att. at 83). Further, the retained bidder offered a monthly discount to the Company if the total hours worked in a given month exceeded the hours worked in the same month relative to the prior rate case, D.P.U. 08-35 (Exh. DPU-NEGC-1-4, Att. at 83; Tr. 2, at 267).[152] In addition, the estimated range of overall legal expenses quoted by the retained bidder is within the range expected for a proceeding of this magnitude and comparable to the firm's overall charges in the Company's last rate case.

For these reasons, we reject the Attorney General's arguments concerning the retention of legal counsel in this case. We find that, in this instance, the Company has sustained its burden of demonstrating that the selection of the retained bidder was reasonable and appropriate and that the costs associated with this provider were prudently incurred. We stress, however, that our decision today should not deter experienced law firms such as the two rejected bidders from responding to future RFPs from utilities seeking rate case legal representation. Nor should the retained law firm read our decision today as an endorsement of its retention as counsel in future rate cases. We expect that all electric and gas distribution companies will continue to use a fair, open, and transparent RFP process to select legal counsel, and we will continue to require companies to demonstrate that such selection satisfies the Department's long-standing service provider retention requirements.

d. 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

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[152] The record reveals that the Company has benefited from this discount on five occasions throughout the course of this case, for a total savings of $37,500 (Exh. DPU-NEGC-5-7(B) Supp. at 2).

services performed. D.T.E. 03-40, at 157; D.T.E. 02-24/25, at 193-194; D.T.E. 01-56, at 75; D.T.E. 98-51, at 61; D.P.U. 96-50 (Phase I) at 79. Further, we have stated that failure to provide this information could result in the Department's disallowance of all or a portion of rate case expense. D.T.E. 02-24/25, at 193; D.P.U. 96-50 (Phase I) at 79. No intervenor commented on the particular invoices submitted by the Company.

The Department has reviewed the invoices and finds that they are properly itemized for allowable expenses with two exceptions concerning legal expenses. First, the Department finds that two entries, totaling $720, were improperly billed to this matter and, therefore, are disallowed for recovery (Exh. DPU-NEGC-5-7(C) Supp. at 11, 36). Second, the legal expenses include $39,670 for in-house photocopying charges (Exh. DPU-NEGC-5-7(C) Supp. at 22, 40, 51, 71, 87, 101). While we acknowledge that legal counsel likely engaged in in-house photocopying, the only documentation of this activity is a line-item amount on the various legal bills. There is no evidence to support the number of copies made, or the per-page charge. As such, we are unable to discern whether the charges for the photocopying were reasonable or excessive. Consequently, we disallow the charges related to legal counsel's in-house photocopying.

We note that the Company has included in its rate case expense $38,552 in fees related to completion of the rate proceeding (Exh. DPU-NEGC-5-7 Supp., Att. A). These include fees for the following items: (1) cost of capital analysis; (2) the decoupling and TIRF proposals, updated marginal cost study, allocated cost study, and rate design proposal; (3) cost of service analysis; and (4) legal representation; (Exh. DPU-NEGC-5-7 Supp., Att. A).

The Department's long-standing precedent allows only known and measurable changes to test year expenses to be included as adjustments to cost of service. D.T.E. 03-40, at 161; D.T.E. 02-24/25, at 195; D.T.E. 98-51, at 61-62. Proposed adjustments based on projections or estimates are not known and measurable, and recovery of those expenses is not allowed. D.T.E. 03-40, at 161-162; D.T.E. 02-24/25, at 196; D.T.E. 01-56, at 75. The Department does not preclude the recovery of fixed fees for completion of compliance filing work in a rate case, but the reasonableness of the fixed fees must be supported by sufficient evidence. D.T.E. 03-40, at 162; D.T.E. 02-24/25, at 196. Given an adequate showing of the reasonableness of fixed contracts to complete a case after the record closes and briefs are filed, a company may qualify to recover such expenses. D.T.E. 03-40, at 162; D.T.E. 02-24/25, at 196. We have stated that documented and itemized proof, however, is a prerequisite to recovery. D.T.E. 03-40, at 162; D.T.E. 02-24/25, at 196. Assuming that the fixed fee agreement is properly supported, the fact that the consultants and the company have agreed to complete the service for a fixed fee gives the Department a level of confidence in the reasonableness of the level of effort and consequent expenditure to carry the case through to the compliance filing. See D.P.U. 10-55, at 338.

As noted above, with two exceptions, the Company is permitted to recover the rate case expense amounts submitted at the close of the record. NEGC did not negotiate any separate fixed fee contracts with its remaining consultants or legal counsel for the work necessary to complete this case (See Exh. DPU-NEGC-1-4, Att. at 32-37, 82-84, 154-156).[153] NEGC's proposed adjustments for compliance work are based on projections or estimates and are not known and measurable (Exh. DPU-NEGC-5-7 Supp., Att. A).

Consistent with long-standing precedent, because the proposed rate case expense adjustments are based upon estimates or projections to complete this proceeding, they are insufficient to demonstrate known and measurable changes that permit recovery of those expenses. D.T.E. 03-40, at 161-162; D.T.E. 02-24/25, at 195-196; D.T.E. 01-56, at 75; D.T.E. 01-50, at 22. Accordingly, we disallow the estimated costs to complete this proceeding, which total $38,552.

e. Normalization of Rate Case Expenses

As set forth above, NEGC argues that, in order to avoid the write-off of a substantial amount of the uncollected balance of rate case expense incurred in D.P.U. 08-35, the Department should include this amount in the overall calculation of rate case expense in this case (see, e.g., Company Brief at 31). Though not raised on brief, the Company in its testimony and discovery responses asserts that if the unamortized balance of rate case expense incurred in D.P.U. 08-35 is excluded from the calculation of overall rate case expense subject to normalization in this case, the Department should apply a three-year normalization period to the total rate case expenses incurred in this matter (Exhs. NEGC-JMS-1, at 32-33; AG-22-16).

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153 It appears that the Company's cost of service consultant included in its bid response to the RFP costs associated with post-briefing work (Exh. DPU-NEGC-1-4, Att. at 188, 193). Given that this provider's total costs exceeded the fixed bid amount (see Exh. DPU-NEGC-5-7 Supp., Att. A), however, the Company is not entitled to recover any further costs associated with this provider.

The Attorney General asserts that the Department should reject the Company's proposal to allow recovery of the unamortized balance of rate case expense from D.P.U. 08-35, and instead should apply the traditional normalization precedent to the total rate case expenses incurred in the instant case (Attorney General Brief at 54-55, citing D.P.U. 10-55, at 339; D.P.U. 09-39, at 295-296; D.P.U. 09-30, at 241; D.PU. 08-35, at 135; D.P.U. 08-27, at 75-76).

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.T.E. 05-27, at 163; D.T.E. 03-40, at 163; D.T.E. 02-24/25, at 197; D.T.E. 98-51, at 62; D.P.U. 95-40, at 57-58. The Department's practice is to normalize rate case expenses so that a representative annual amount is included in the cost of service. D.T.E. 05-27, at 163; D.T.E. 03-40, at 163; D.T.E. 02-24/25, at 191; D.T.E. 01-56, at 77; D.T.E. 98-51, at 53; D.P.U. 96-50 (Phase I) at 77; The Berkshire Gas Company, D.P.U. 1490, at 33-34 (1983). Normalization is not intended to ensure dollar-for-dollar recovery of a particular expense; rather, it is intended to include a representative annual level of rate case expense. D.T.E. 05-27, at 163; D.T.E. 03-40, at 163-164; D.T.E. 02-24/25, at 191; D.P.U. 96-50 (Phase I) at 77. The Department has previously determined that the basis for developing rate case expense is to identify the most likely period of time in which a company would incur a future rate case expense. See D.P.U. 92-78, at 57, citing D.P.U. 1490. The intent of the Department is to allow a company to normalize and recover sufficient revenues during that time period to meet the expense when it is likely to be incurred again. D.P.U. 92-78, at 57.

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.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 (1986).

We find that the representative level of rate case expense to be included in rates is the normalized amount of rate case expense incurred in this proceeding. Because the Company has filed a base rate proceeding before the normalization period of its last rate case ended, the rate case expense associated with D.P.U. 08-35 is no longer subject to recovery. See, e.g., D.P.U. 91-106/91-138, at 19-21. Further, the Department finds no compelling reason to accord these expenses special consideration and include them in the annual normalization amount approved in this proceeding. See D.P.U. 91-106/91-138, at 20-21. The Company determined the timing of the filing of this rate case, and did so with full knowledge of the Department's normalization precedent. As noted above, normalization is not intended to ensure dollar-for-dollar recovery of a particular expense. 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.

Based on the average interval of its last four rate case filings, the Department concludes that the appropriate normalization period for NEGC is five years.[154] The Department concludes that mechanical application of this method does not produce an unreasonably long normalization period, and that the facts of this case do not warrant a departure from the Department's general precedent in applying this mathematical formula. We do not find that NEGC's "under-recovery" of its normalized rate case expense from D.P.U. 08-35 will have an adverse effect on the Company's financial integrity, especially considering the base rate increase authorized by this Order and with the Department's approval of a decoupling mechanism and TIRF.

Based on the above considerations, we reject the Company's proposal to recover the unamortized balance of rate case expense from D.P.U. 08-35. Further, we decline to normalize the recoverable rate case expense associated with the instant case over a shorter period than provided by our traditional normalization methodology.

Finally, we have previously determined that there are clear benefits to shareholders from approval of rate increases. See, e.g., D.P.U. 10-55, at 343; D.P.U. 08-35, at 135. The Company's proposal that its rate case expense be amortized and recovered through a reconciling mechanism is in direct conflict with the Department's determination that it may be appropriate for shareholders to shoulder a portion of such expense. D.P.U. 10-55, at 343;

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154 The Company's last four rate cases include the current case, D.P.U. 08-35, D.T.E. 07-46, and D.P.U. 96-60 (Exh. NEGC-JMS-2, Sch. G-19 (Rev.)). The sum of the three time intervals between these cases (2.17 plus 1.10 plus 11.07), divided by three and rounded to the nearest whole number, results in a normalization period of five years (Exh. NEGC-JMS-2, Sch. G-19 (Rev.)).

D.P.U. 08-35, at 135.[155] Thus, we find it inappropriate to establish a reconciling mechanism to recover rate case expense. In addition, as one means to demonstrate that rate case expense has been contained, the Department directs gas and electric companies in future rate case filings to consider proposals for some portion of the rate case expense to be borne by shareholders.

4. Conclusion

The Department has adjusted rate case expense as set forth above, and denies recovery of the unamortized balance from D.P.U. 08-35. These findings result in an allowable rate case expense recovery of $948,472. Further, as explained above, the Department finds that the reasonable normalization period for rate case expense is five years. Thus, the Department concludes that the correct level of normalized rate case expense is $189,694 (i.e., $948,472 divided by five years).

The Company booked $379,771 in test year rate case expense, representing what the Company refers to as its amortized rate case expense amounts from D.T.E. 07-46 and D.P.U. 08-35 (Exhs. NEGC-JMS-2, Schs. G-1 (Rev.), G-19 (Rev.)). The Company proposed a reduction in test year cost of service of $35,188 (Exhs. NEGC-JMS-2, Schs. G-1 (Rev.),

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155 The Company's proposal to amortize its costs and recover them through a reconciling mechanism is also in direct conflict with the Department's long-standing precedent that such costs should be normalized. See, e.g., D.T.E. 05-27, at 163; D.T.E. 03-40, at 163-164; D.T.E. 02-24/25, at 191, 197; D.P.U. 96-50 (Phase I) at 77; see also D.P.U. 91-106/91-138, at 20 (other than in specific instances where it has approved a cost tracking mechanism, the Department does not intend rates to be fully reconciling).

G-19 (Rev.)).[156] Accordingly, the Department will further reduce NEGC's cost of service by $154,889 to reflect the annual level of normalized rate case expense of $189,694.

K. Leak Repair Expenses

1. Introduction

During the test year, the Company booked $1,003,715 in expenses associated with the maintenance of mains (Account 887) (Exhs. NEGC-JMS-2, Sch. G-2 (Rev.) at 1, line 53; AG-3-17, Att. A at 5). Of the seven components of mains maintenance expenses, payroll ($427,206) and outside services ($406,243) account for 83 percent of the 2009 total expenses (Exh. AG-3-17, Att. A at 5). The corresponding expense in 2008 was $597,607, with payroll ($253,779) and outside services ($226,490) accounting for 80 percent of the 2008 total expenses (Exh. AG-3-17, Att. A at 5). Therefore, of the $406,108 increase in total mains maintenance expense from 2008 to 2009, $353,181 or 87 percent is accounted for by increases in payroll and outside services expenses (Exh. AG-3-17, Att. A at 5).

The Company explained that the increase in outside services expense from 2008 to 2009 was due to the increase in the number of leaks repaired (Exh. AG-9-17). During the test year, the Company reported to have discovered 709 leaks compared to 502 discovered in 2008 (Exh. AG-4-26, Att.). In 2009, the Company repaired 731 leaks compared to 428 leaks

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156 The Company's proposed reduction in test year cost of service is derived by taking its proposed rate case expense, including the unrecovered balance of rate case expense from D.P.U. 08-35, of $1,722,914 normalized over five years for an annual expense of $344,583 (Exh. NEGC-JMS-2, Sch. G-19 (Rev.)). The Company then subtracted the $344,583 from its prior rate case amortization of $379,771 (Exh. NEGC-JMS-2, Sch. G-19 (Rev.)).

repaired in 2008 (Exhs. AG-4-26, Att.; AG-9-19, Att.).[157] The Company indicated that in 2009, it paid one of its outside vendors, Century Paving and Construction, the amount of $184,720 for outside services compared to $103,337 paid in 2008 (Exh. AG-9-17).[158]

2. Positions of the Parties

a. Attorney General

The Attorney General claims that the $1,004,000[159] expense charged to the Company's maintenance of mains Account 887 in 2009 represents an increase of $406,000 or 68 percent over the maintenance of mains expense of $598,000 incurred in 2008 (Attorney General Brief at 56, citing Exh. AG DJE-1, at 8). The Attorney General contends that the increase in outside services expenses booked to Account 887 is due to the increase in the number of leaks repaired from 2008 to 2009, and represents an abnormal and non-recurring expense that must be normalized to reflect the expense based on a more representative number of leaks repaired (Attorney General Brief at 57-58, citing Exh. AG 3-17).

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157 From 2005 through 2007, the Company reported to have discovered 417, 345, and 322 leaks, respectively, and for the same period repaired 381, 293, and 377 leaks (Exhs. AG-4-26, Att.; AG-9-19, Att.). The Company also provided the number of leaks repaired for each month from January 2006 through October 2010 (Exh. AG-9-19, Att.).

158 Of the $406,243 outside expense incurred in 2009, the Company listed eight vendors, including Century Paving and Construction, that accounted for $395,392 or 97 percent of the 2009 total outside services expense (Exhs. AG-3-17, Att. A at 5; AG-9-17). The other vendors were (1) the police departments of Fall River, Plainville, Somerset, and Swansea, (2) the towns of North Attleboro and Westport, and (3) New England Utility (Exh. AG-9-17). The same group of vendors accounted for $187,879 or 83 percent of the 2008 total outside expense of $226,490 (Exhs. AG-3-17, Att. A at 5; AG-9-17).

159 In her brief, the Attorney General rounded the $1,003,715 booked by the Company in the test year to $1,004,000 (see, e.g., Attorney General Brief at 56).

In support of her position, the Attorney General notes that the amount paid by the Company for outside contractors for leak repairs increased from $188,000 in 2008 to $395,000 in 2009, representing an increase of $207,000 or 110 percent (Attorney General Brief at 57, citing Exh. AG DJE-1, at 9). The Attorney General also notes that the number of leaks repaired increased from 428 in 2008 to 731 in 2009, representing a 71 percent increase (Attorney General Brief at 57). The Attorney General states that the 731 leaks repaired in 2009 represents an increase of approximately 98 percent over the 370 average leaks repaired from 2005 through 2008 (Attorney General Brief at 58, citing Exh. AG DJE-1, at 9-10). Noting that the number of leaks discovered in 2008 exceeded the number of leaks repaired in 2008 by 74, the Attorney General presumes that the increase in the number of leaks repaired in 2009 would have been partly due to the leaks discovered in 2008 but not repaired in that year (Attorney General Brief at 58, citing Exh. AG DJE-1, at 9-10).

Reasoning that NEGC's 2009 leak repair expense does not represent the cost incurred to repair a normal annual level of leaks, the Attorney General proposes a method for normalizing the test year leak repair expense based on what she suggests to be a more representative annual level of leaks repaired and cost per leak (Attorney General Brief at 58-60). The Attorney General first observes that the most recent twelve months of available data ended October 31, 2010, show that the number of leaks repaired was 530 (Attorney General Brief at 58, citing Exh. AG DJE-1, at 10). The Attorney General claims that the Company did not dispute that the number of leaks repaired in the 2009 test year was significantly higher than in any other recent period (Attorney General Brief at 58, 60; Attorney

General Reply Brief at 11, citing Company Brief at 34). Accordingly, the Attorney General suggests that this 530 leaks repaired could serve as a reasonable basis for calculating a normalized leak repair expense level (Attorney General Brief at 58, citing Exh. AG-DJE-1, at 10).

The Attorney General disputes the Company's claim that any decrease in the number of leaks repaired from the 2009 levels, compared to the leaks repaired during the twelve-month period ended October 31, 2010, is being offset by increases in the cost-per-leak repair (Attorney General Reply Brief at 11, citing Company Brief at 33). Noting that the cost-per-leak repair in the twelve months ended October 31, 2010, was $748.34 compared to the 2009 test year cost of $540.89, or a 38.3 percent increase, the Attorney General claims that the Company has provided no evidence that the cost-per-leak repair incurred in that twelve-month period is representative of the normal cost-per-leak repair that will be incurred prospectively (Attorney General Reply Brief at 59).

In addition, the Attorney General contends that the higher cost of asphalt is the only source of the increase in the cost that was cited by the Company (Attorney General Reply Brief at 11, citing Company Brief at 33). The Attorney General claims that the only component of the contract of the Company with Century Paving and Construction that changed within the existing price structure is the 25 percent increase in the base level of material asphalt cost (Attorney General Reply Brief at 11, citing Company Brief at 33). Noting that during the test year, the Company paid $184,720 to Century Paving and Construction for leak repairs, and assuming that 100 percent of the amount paid to Century Paving and Construction was solely for asphalt, an assumption she characterized to be "most conservative," the Attorney General reasons that an increase of 25 percent in the price of asphalt would result in adjusted payment to Century Paving and Construction of $230,900, or an increase of $46,180 (Attorney General Reply Brief at 11-12, citing Exh. REB-JMS-3).

The Attorney General added this $46,180 increase to the $395,392 total actual expense for outside services in 2009, resulting in revised expense of $441,572 (Attorney General Reply Brief at 12). The Attorney General claims that this amount represents the total 2009 leak repair expense for outside services adjusted for the increase in the price of asphalt (Attorney General Reply Brief at 12, citing Exh. REB-JMS-3). Based on the 731 leaks repaired in 2009, the Attorney General claims that the pro forma cost-per-leak repair in 2009, adjusted for the increase in the price of asphalt, would be $604.06 ($441,572 / 731) (Attorney General Reply Brief at 12).

Multiplying this adjusted test year cost-per-leak repair of $604.06 by the 530 leaks repaired during the twelve-month period ended October 31, 2010, results in an annual level of leak repair expense from outside services equal to $320,155, which the Attorney General observes to be $75,237 less than the 2009 actual leak repair expense from outside services of $395,392 (Attorney General Reply Brief at 12). The Attorney General, accordingly, recommends that the Department reduce the Company's proposed cost of service by $75,237, in order to normalize the test year leak repair expense (Attorney General Reply Brief at 12).

b. <u>Company</u>

The Company asserts that its leak repair expense is reasonable and consistent with the costs associated to maintain the system in a prudent, safe, and reliable manner (Company Brief at 32). The Company claims that the actual repair cost has increased significantly due to the price of asphalt, which is driven in part by the price of oil (Company Brief at 32, <u>citing</u> Tr. 8, at 1004; RR-AG-17). The Company states that in 2008, it was paying approximately $54 dollars per ton of asphalt but is currently paying approximately $70 per ton, or an increase of 25 percent, for a material that is both vital and integral to the Company's ability to repair leaks (Company Brief at 33, <u>citing</u> Tr. 8, at 1004-1005). The Company also points out that the cost of leak repairs is interrelated with the costs associated with excavation and construction (Company Brief at 33, <u>citing</u> Tr. 8, at 1004).

The Company disputes the Attorney General's position that leak repair costs incurred during the test year are unrepresentative. NEGC contends that there is no evidence in the record to support a contention that the cost of oil, which drives the price of asphalt, will be falling to levels experienced in 2008 (Company Brief at 32, <u>citing</u> Exh. RR-AG-17; Tr. 8, at 1004-1005). The Company adds that, for a number of reasons, it has used Century Paving and Construction since 2006 because, throughout the term of the contract, the non-asphalt price to the Company has remained flat, and that the only component of the contract that changed within the existing price structure is the base level of material asphalt cost (Company Brief at 33, <u>citing</u> Tr. 8, at 1004-1005; RR-AG-17).

The Company asserts that the drivers of cost increases are not within its control and that the increased costs associated with its leak repairs are derived not from some anomaly but rather from a sharp increase in costs seen in the oil market that occurred in 2009, with no indication that costs will recede at any point in the near future (Company Brief at 33). The Company claims such an increased level of leak repair costs is required in order to maintain the high level of replacement activity proposed by the Company during the course of this proceeding (Company Brief at 33-34, citing Exh. NEGC-REB-JMS-3).

The Company claims that the Attorney General's own witness conceded that his position on this matter was based on a series of assumptions and that, if the cost per leak were higher as a permanent condition, then his adjustments would have to be modified accordingly (Company Brief at 34, citing Tr. 7, at 887-888). The Company claims that, although it has repaired more leaks during the test year than in the prior years, it has also shown that the costs incurred are not abnormal but rather reflect the actual costs incurred to make such repairs (Company Brief at 34). The Company concludes that its leak repair expense is reasonable and prudently incurred and therefore should be accepted by the Department (Company Brief at 34).

3. Analysis and Findings

It is well-established Department precedent that base rate filings are based on an historic test year, adjusted for known and measurable changes. See D.P.U. 1580, at 13-17, 19; Massachusetts Electric Company, D.P.U. 136, at 3 (1980); Chatham Water Company, D.P.U. 19992, at 2 (1980); Massachusetts Electric Company, D.P.U. 18204, at 4 (1975); New England Telephone &Telegraph Company, D.P.U. 18210, at 2-3 (1975); Boston

Gas Company, D.P.U. 18264, at 2-4 (1975). In establishing rates pursuant to G.L. c. 164, § 94, the Department examines a test year, which usually represents the most recent twelve-month period for which complete financial information exists, on the basis that the revenue, expense, and rate base figures during that period, adjusted for known and measurable changes, provide the most reasonable representation of a distribution company's present financial situation, and fairly represent its cost to provide service. See Ashfield Water Company, D.P.U. 1438/1595, at 3-4 (1984). The selection of the test year is largely a matter of a distribution company's choice, subject to Department review and approval. See D.P.U. 07-50-A at 51.

The Department has stated that test year expenses, which recur on an annual basis, are eligible for full inclusion in cost of service unless the record supports a finding that the level of the expense in the test year is abnormal. D.P.U. 1270/1414, at 33. If a finding is made that the test year expense is abnormal, it is necessary to normalize the expense to reflect the amount that is likely to recur on a normal annual basis. D.P.U. 1270/1414, at 33. In addition, the Department has stated that the "normalization of an expense is not intended to ensure dollar-for-dollar recovery of a particular expense, rather is intended to recover a representative annual level of [such an] expense." D.P.U. 10-55, at 312 n.217, citing D.P.U. 07-71, at 103; D.T.E. 05-27, at 163; D.T.E. 03-40, at 163-164; D.P.U. 91-106/91-138, at 20-21.

Here, the Attorney General has proposed to normalize the Company's test year leak repair expense because she claims that the 731 leaks repaired during the 2009 test year are abnormally high. Instead, she recommends using the 530 leaks repaired during the twelve-month period ended October 31, 2010, as the more representative number of leaks repaired. Based on this lower number of leaks repaired and taking into account changes in the cost of outside services, the Attorney General proposed a pro forma normalization adjustment that would reduce the Company's test year leak repair expense by $75,237. In making such an adjustment, the Department must first accept the Attorney General's calculations for the number of leaks repaired during the test year. We address this matter below.

The record shows that for the period 2005 through 2009, the Company discovered 417, 345, 322, 502, and 709 leaks, respectively (Exh. AG-4-26, Att.). These annual leaks discovered represent the following annual changes: negative 17 percent from 2005 to 2006; negative seven percent from 2006 to 2007; 56 percent from 2007 to 2008; and 41 percent from 2008 to 2009 (Exh. AG-4-26, Att.). The record also shows that for the same period 2005 through 2009, the Company repaired 381, 293, 377, 428, and 731 leaks, respectively (Exh. AG-4-26, Att.). These annual leaks repaired represent the following annual changes: negative 23 percent from 2005 to 2006; 29 percent from 2006 to 2007; 14 percent from 2007 to 2008; and 71 percent from 2008 to 2009 (Exh. AG-4-26, Att.).

Regarding the Attorney General's claim that the 731 total leaks repaired in 2009 is abnormally high, we note that the total leaks discovered in 2009 increased by 41 percent from the 2008 (Exh. AG-4-26, Att.). This 41 percentage increase in total leaks discovered, however, is still relatively low compared to the 71 percent increase in total leaks repaired from 2008 to 2009 (Exh. AG-4-26, Att.).

The record also shows that for years 2005 through 2009, the Company discovered 113, 58, 94, 101, and 146 Grade 1 leaks, respectively (Exhs. AG-4-26, Att.; AG-9-19, Att.).[160] These annual Grade 1 leaks discovered represent the following annual changes: negative 49 percent from 2005 to 2006; 62 percent from 2006 to 2007; seven percent from 2007 to 2008; and 45 percent from 2008 to 2009.

The record further shows that for years 2005 through 2009, the Company repaired 115, 59, 94, 101, and 146 Grade 1 leaks, respectively (Exhs. AG-4-26, Att.; AG-9-19, Att.). These annual Grade 1 leaks repaired represent the following annual changes: negative 49 percent from 2005 to 2006; 59 percent from 2006 to 2007; seven percent from 2007 to 2008; and 45 percent from 2008 to 2009. The annual percent changes in Grade 1 discovered and annual percentage changes in Grade 1 leaks repaired are equal, except for the period from 2006 to 2007 where the increase in Grade 1 leaks discovered was 62 percent compared to 59 percent increase in Grade 1 leaks repaired. This phenomenon is explained by the fact that Grade 1 leaks are considered to warrant immediate action, so the Company repairs them immediately when discovered (Exh. AG-12-25; Tr. 5, at 626).

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160 Pursuant to industry standards, gas leaks are classified as: (1) Grade 1, a leak that represents an existing or probable hazard to persons or property, and requires immediate repair or continuous action until the conditions are no longer hazardous; (2) Grade 2, a leak that is recognized as being non-hazardous at the time of detection, but, requires scheduled repair based on probable future hazard; and (3) Grade 3, a leak that is non-hazardous at the time of detection and can be reasonably expected to remain non-hazardous. <u>The Gas Piping Technology Committee Guide for Gas Transmission and Distribution Piping Systems</u>, Material Appendix G-192-11; <u>see</u> <u>also</u> 49 C.F.R. Part 192, §§ 192.615(a)(1); 192.703(c); 220 C.M.R. § 101.06(21)(e).

Although the percentage increases of Grade 1 leaks discovered and repaired from 2008 to 2009 were both equal to 45 percent, this component increase does not appear to fully explain the 71 percent increase in total leaks repaired over that period. As discussed below, the number of Grade 2 and Grade 3 leaks discovered and repaired could explain this difference.

More specifically, in 2008 and 2009, the Grade 2 leaks discovered and repaired increased by 54 percent and 67 percent, respectively (Exh. AG-9-19, Att.). During the same years, the Grade 3 leaks discovered and repaired increased by 29 percent and 93 percent, respectively (Exh. AG-9-19, Att.). Thus, the remaining unexplained 26 percent increase in total leaks repaired in 2008 and 2009 (71 percent for total repairs minus 45 percent for Grade 1) is explained by the increases in the number of Grade 2 and Grade 3 leaks repaired.

The record shows that for the years 2005 through 2009, the percentages of Grade 1 leaks repaired compared to the total annual number of leaks repaired are: 30 percent, 20 percent, 25 percent, 24 percent, and 20 percent, respectively (Exhs. AG-4-26, Att.; AG-9-19, Att.). These relatively stable annual percentages of the number of Grade 1 leaks repaired, relative to total annual number leaks repaired, indicate that, to a certain degree, Grade 1 leaks influence and determine the number of Grade 2 and Grade 3 leaks repaired.

For example, the record shows that in prioritizing its main replacement projects for leak-prone pipes, including bare steel and cast iron mains, the Company makes a continuing record of the locations of leaks (1) discovered, (2) repaired, and (3) discovered and repaired (i.e., Grade 1 leaks) (Tr. 5, at 627). After a certain period of time when new leaks arise that require immediate repairs, i.e., Grade 1, in that same segment of pipe where leaks were previously repaired, the Company would decide to replace the entire pipe instead of just clamping or repairing the new Grade 1 leaks discovered (Tr. 5, at 627-628). Thus, replacing the entire segment of that leak-prone pipe would necessarily eliminate all the Grade 2 leaks, as well as all the Grade 3 leaks that could have accumulated in that pipe segment for a considerable period of time. Therefore, this replacement of a leak-prone pipe arising from the occurrences of Grade 1 leaks correspondingly increases the number of Grade 2 and Grade 3 leaks repaired.

Based on the above considerations, and given the various types of material and structural configurations of the Company's distribution mains, services, and other related facilities, including the length of time that those facilities have been in the ground under the continuing impacts of weather and the environment, it would be difficult if not impossible for the Department in this case to determine and establish an annual number of leaks that would reasonably represent the number of annual future leaks that will be repaired by the Company. In the case of Grade 1 leaks, it would be virtually impossible to establish such a representative number of leaks repaired because the occurrence of those leaks cannot be reliably predicted, but must be repaired immediately. In this circumstance, the Department finds that the Company's booked expense associated with the maintenance of mains is appropriate for inclusion in NEGC's cost of service.

We deny the Attorney General's recommendation to use the 530 leaks repaired over the twelve-month period ended October 1, 2010, and accept the 731 leaks repaired by the

Company during the test year. Accordingly, we reject the Attorney General's recommendation to reduce the Company's test year leak repair expense by $75,237.

L. Depreciation Expense

1. Introduction

During the test year, NEGC booked $3,747,606 in depreciation expense (Exhs. NEGC-JMS-2, Sch. G-1 (Rev.) line 26). NEGC proposed to increase this test year depreciation expense by $128,398 (Exhs. NEGC-JMS-2, Sch. G-1 (Rev.) line 26; NEGC-JMS-2, Sch. G-22 (Rev.) line 51). In determining this proposed adjustment, the Company used the same depreciation accrual rates approved in its last rate case, D.P.U. 08-35 (Exhs. NEGC-JMSw-1, at 8; NEGC JMS-1, at 34; RR-DPU-8 Att. A at 1).[161]

The Company first calculated a total depreciation expense of $4,010,330 by applying account-specific depreciation accrual rates to the test year-end depreciable plant balances in its Fall River and North Attleboro service areas (Exhs. NEGC-JMS-1, at 34; NEGC-JMS-2, Sch. G-22 (Rev.) line 46). Then the Company reduced this amount by $134,326,[162] which represents the depreciation expense associated with the transportation and power-operated equipment that was previously leased by NEGC but included in the buy-out of that lease

161 The Company stated that it did not prepare an updated depreciation study because there have been no operational or other changes that have occurred in the past three years that could change the results of the deprecation study filed and approved in D.P.U. 08-35 (Exh. NEGC-JMSw-1, at 8). The Company provided the prior deprecation study that was approved in D.P.U. 08-35 (Exh. AG-4-34, Att. (B)).

162 This depreciation expense adjustment of $134,326 consists of $123,367 for transportation equipment and $10,959 for power-operated equipment (Exh. NEGC-JMS-2, Sch. G-22 (Rev.) lines 38 and 42).

(Exhs. NEGC-JMS-1, at 34; NEGC-JMS-2, Schs. G-7 (Rev.) line 6, G-22 (Rev.) line 47; NEGC-JMS-3, WP G-7, line 6). This reduction results in an adjusted total depreciation expense of $3,876,004 (Exh. NEGC-JMS-2, Sch. G-22 (Rev.) line 48). The difference between this amount and the test year booked depreciation expense of $3,747,606 is $128,398, representing the Company's proposed adjustment (Exhs. NEGC-JMS-2, Schs. G-1 (Rev.) line 26, G-22 (Rev.) line 51).

2. Positions of the Parties

a. The Attorney General

The Attorney General did not contest the Company's use of its existing depreciation accrual rates.[163] She proposes a reduction in the Company's pro forma depreciation expense in the amount of $45,000, however, claiming that this adjustment will prevent NEGC from over-recovering depreciation expenses on Accounts 305, 311, and 366 during the time that rates established in this case are in effect (Attorney General Brief at 64-65, citing Exh. AG-DJE at 15; RR-DPU-60).

In support of her proposal, the Attorney General observes that the Company's proposed pro forma depreciation and amortization expense calculation indicates that several of the Company's plant accounts were nearly fully depreciated as of December 31, 2009 (Attorney General Brief at 64, citing Exh. NEGC-JMS-2, Sch. 6). The Attorney General argues that if the pro forma depreciation expense on these plant accounts is not adjusted, the Company's

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[163] In determining the proposed pro forma adjustment in the Company's depreciation expense described below, the Attorney General applied the accrual rates in the depreciation study filed and approved in D.P.U. 08-35.

rates will continue to reflect recovery of that depreciation expense even after the plant is fully depreciated (Attorney General Brief at 64, citing Exh. AG-DJE-1, at 15). The Attorney General's proposed pro forma reduction in the Company's depreciation expense in the amount of $45,000 is based on the application of a method that considers, among other factors, the remaining net plant balance as of December 31, 2009, the cost of removal net of salvage value, and the remaining balance to be recovered spread over the remaining life of the plant (Attorney General Brief at 64-65, citing Exh. AG-DJE-1, at 15).

The Attorney General claims that the Company does not dispute that some of its plant accounts will be fully depreciated, or nearly fully depreciated, by the time the rates in this case take effect, and that absent any adjustment to the depreciation expense on those accounts, the Company's rates will continue to reflect depreciation on those plant accounts after they are fully depreciated (Attorney General Reply Brief at 13).[164] Regarding the Company's assertion that there is no precedent to support her proposed adjustment, the Attorney General argues that the Company does not cite any cases in which the Department has rejected such an adjustment, and that such an adjustment to avoid over-recovery of depreciation on fully-depreciated plant accounts would not be inconsistent with any Department precedent (Attorney General Reply Brief at 13, citing Company Brief at 35).

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164 The Attorney General, for example, notes that the remaining net plant balance in Account 366 as of December 31, 2009 was $19,500 and that the annual depreciation on that account is $19,270 (Attorney General Brief at 64, citing Exh. AG-DJE-1, at 15). The Attorney General argues that by the end of year 2010, that account would have been fully depreciated (Attorney General Brief at 64, citing Exh. AG-DJE-1, at 15).

b. Company

NEGC contends that the Attorney General's proposal to reduce the Company's proposed depreciation expense by $45,000 is unfair and unprecedented and, thus, must be rejected (Company Brief at 35, citing Attorney General Brief at 64-65)). The Company states that the Attorney General's recommendation is based on post-test-year plant adjustments and claims that the Attorney General cannot cite any precedent in which the Department has made this type of post-test-year adjustment affecting depreciation expense (Company Brief at 35, citing Tr. 7, at 889). In addition, the Company asserts that the Attorney General's proposal fails to recognize depreciation expense associated with post-test-year additions to rate base that would affect NEGC's depreciation expense (Company Brief at 35, citing Tr. 8, at 890).

3. Analysis and Findings

Depreciation expense allows a company to recover its capital investments in a timely and equitable fashion over the service lives of the investments. D.P.U. 08-27, at 110; D.T.E. 98-51, at 75; D.P.U. 96-50 (Phase I) at 104; D.P.U. 84-135, at 23. Depreciation studies rely not only on statistical analysis but also on the judgment and expertise of the preparer. D.P.U. 08-27, at 110; D.T.E. 02-24/25, at 132; D.P.U. 92-210, at 71; D.P.U. 92-111, at 121; The Berkshire Gas Company, D.P.U. 905, at 13-15 (1982). In addition, the Department has stated that it is necessary to go beyond the numbers presented in a depreciation study and consider the underlying physical assets. D.P.U. 08-27, at 110; D.P.U. 92-250, at 64; D.P.U. 905, at 13-15.

Based on our review of the record in this case, it is reasonable to accept the Company's proposition that there has been no significant change in its operations that could materially affect the results of the deprecation study filed and approved in D.P.U. 08-35. Accordingly, we find that using the depreciation accrual rates approved in D.P.U. 08-35 in this case would result in just and reasonable rates.

Regarding the Attorney General's proposal to reduce the Company's pro forma depreciation expense by $45,000, the record demonstrates that this adjustment is associated with three accounts: (1) Account 305 (structures and improvements, production plant); (2) Account 311 (liquefied petroleum gas equipment, production plant); and (3) Account 366 (structures and improvements, distribution plant) (RR-DPU-60, Sch. DJE-4;[165] see also Exh. NEGC-JMS-2, Schs. B (Rev.), C (Rev.)). In calculating her proposed adjustment, the Attorney General first calculated for each account the total balance to be recovered, which is equal to the net plant as of December 31, 2009, plus the cost of removal net of salvage value (Tr. 7, at 900-904, 906-907; RR-DPU-60, Sch. DJE-4).[166] Next, the Attorney General divided the total account balance to be recovered by the remaining life of the respective plant asset to determine the annual recovery amount (Tr. 7, at 900-904, 906-907; RR-DPU-60,

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165 Record Request DPU-60 revises Schedule DJE-4 and the other schedules in Exhibit AG-DJE-1 that are affected by this proposed adjustment (Tr. 7, at 901-902).

166 More specifically, to determine the cost of removal/salvage, the Attorney General multiplied the account gross plant as of December 31, 2009, by the cost of removal/salvage factor based on the depreciation study approved in D.P.U. 08-35 (RR-DPU-60, Sch. DJE-4).

Sch. DJE-4).[167] Finally, because the Attorney General noted that the result of her calculation was less than the annual depreciation, she took the difference of these two items for each of the three accounts and added those differences to derive her proposed adjustment (Tr. 7, at 900-904, 906-907; RR-DPU-60, Sch. DJE-4). The total of the differences for those three accounts is $45,602 (see RR-DPU-60, Sch. DJE-4).[168] The Attorney General further stated there are no other accounts that would need such an adjustment (Tr. 7, at 906-907).

The Attorney General's proposal attempts to track depreciation expense by specific plant accounts to prevent over-recovery of depreciation expense. The remaining life depreciation method, as used by NEGC, is designed to account for any previous under- or over-accruals to plant accounts. D.P.U. 08-27, at 103; Boston Gas Company, D.P.U. 19470, at 46, 51 (1978). There is, however, little recent Department precedent on the arguments raised in this proceeding. Therefore, in order to evaluate the merits of the Attorney General's proposal, the Department will rely on analogous case law.

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167 The calculated total balance to be recovered for Account 305, Account 311 and Account 366 are $179,119, $64,936, and $95,069, respectively, while the corresponding remaining lives of the asset are 22 years, 12 years and 23 years (see RR-DPU-60, Sch. DJE-4).

168 The annual depreciation associated with Account 305, Account 311, and Account 366 is $21,088, $23,184, and $19,270, respectively (Exh. NEGC-JMS-2, Sch. G-22 (Rev.)). The corresponding annual recovery, based on the Attorney General's method of calculations but without rounding to the nearest $1,000, are $8,142, $5,647, and $4,151, respectively (see RR-DPU-60, Sch. DJE-4). The difference between the annual depreciation and annual recovery are $12,946, $17,537, and $15,119, respectively, for a total of $45,602 (see RR-DPU-60, Sch. DJE-4).

In the past, the Department has accepted cost of service adjustments similar to that proposed by the Attorney General, such as those relating to expiring leases. D.P.U. 10-55, at 266-267; D.P.U. 09-39, at 158-159; D.P.U. 89-114/90-331/91-80 (Phase One) at 153; D.P.U. 87-260, at 75. In those cases, however, the relevant leases were due to expire shortly after the issuance of the Department's Orders. Although other lease expense had been included in cost of service, there was no evidence that additional leases would be executed. In contrast, it is undisputed that NEGC has added plant of various types on an ongoing basis, and will continue to do so annually. Even if the Company no longer incurs depreciation expense on these particular plant accounts, there are other plant accounts for which the Company will incur depreciation expense in the future.

Based on the foregoing analysis, the Department is unpersuaded that a reduction to NEGC's proposed depreciation expense for Accounts 305, 311, and 366 is warranted. Therefore, the Department declines to accept the Attorney General's proposal.

To calculate NEGC's annual depreciation expense, the Department has applied the accrual rates approved in D.P.U. 08-35 to the Company's depreciable plant balances included in rate base.[169] As noted in Section V.B.4., above, the Department has excluded from cost of service $17,861 in depreciation expense associated with disallowed plant investment. The Department has also excluded from rate base $192,082 in joint capitalizable plant (see Section V.H., above). To derive the depreciation expense associated with excluded joint

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169 The Company's revised cost of service schedules incorporate an offset of $184,888 that was attributed to the additional construction work in progress identified by the Company during the proceedings (Exhs. NEGC-JMS-2, Sch. C-1; AG-9-5).

capitalized plant, the Department has multiplied the $192,082 by 4.38 percent, representing the Company's composite depreciation accrual rate applicable to depreciable plant (i.e., plant investment less land) (see Exh. NEGC-JMS-2, Sch. G-22 (Rev.)). This calculation produces a depreciation expense of $8,413. Therefore, the Department will reduce the Company's proposed depreciation expense by an additional $8,413, resutling in a total reduction of $26,274. Accordingly, the Department will reduce NEGC's proposed cost of service by $26,274.

M. Property Taxes

1. Introduction

During the test year, NEGC booked $1,129,926 in property tax expense associated with utility property (Exh. NEGC-JMS-2, Sch. G-23). The Company proposes to increase its test year cost of service by $45,194 for property tax expense (Exh. NEGC-JMS-2, Sch. G-23). To calculate this adjustment, the Company first determined that its total net plant subject to property taxes as of December 31, 2008, was $54,466,872 (Exh. NEGC-JMS-3, WPs G-23.3 to G-23.6). The Company then divided its total tax payments relating to its December 31, 2008 plant assessment of $1,136,869 by the $54,466,872 net plant subject to property taxes, producing an effective tax factor of 2.0873 percent (Exhs. NEGC-JMS-1, at 34-35; NEGC-JMS-3, WP G-23.1). This effective tax rate of 2.0873 percent, multiplied by the Company's net plant subject to property taxes of $56,298,574, produced a pro forma property tax expense of $1,175,120, representing an increase of $45,194 to test year cost of service

(Exhs. NEGC-JMS-2, Sch. G-23; NEGC-JMS-3, WP G-23.1 (Rev.)). No party commented on this matter on brief.

2. Analysis and Findings

The Department's general policy is to base property tax expense on the most recent property tax bills a utility receives from communities in which it has property. D.P.U. 08-35, at 150; D.P.U. 96-50 (Phase I) at 108-109; D.P.U. 86-280-A at 7, 17; Colonial Gas Company, D.P.U. 84-94, at 19 (1984). NEGC's shorthand approach to calculating property tax is inconsistent with the Department's policy.

While property taxes are assessed to the Company as of January 1st of each year, taxing authorities operate on a fiscal year basis ending June 30th (RR-DPU-23). Consequently, taxing authorities send out their first and second fiscal quarter tax billings during the third and fourth calendar quarters of the year being assessed, based on one-fourth of the prior fiscal year's total final tax amount (RR-DPU-23). Consequently, the Company's tax billings for the third and fourth quarters of 2010 are each equal to approximately one-fourth of its final 2009 tax assessment (RR-DPU-23, Atts. B, C). Based on the most recent property tax bills received by the Company for the third and fourth quarter of 2010, totaling $569,695, NEGC's annualized municipal tax expense totals $1,139,390, which represents an increase of $9,464 to NEGC's test year cost of service (see RR-DPU-23, Att. B). Because the Company had proposed an increase of $45,194 to its property tax expense, the Department accordingly will reduce NEGC's proposed cost of service by $35,730.

N. NEG Appliance Allocations

1. Company's Proposal

NEG Appliance is a wholly owned subsidiary of Southern Union that is engaged in the following activities: (1) rental of residential gas-fired water heaters to homeowners; (2) rental of commercial gas-fired water heaters to business/property owners; (3) rental of residential conversion burners used to convert oil systems to natural gas burning systems; (4) rental of commercial conversion burners to property owners; and (5) provision of maintenance and repair services for customer-owned gas equipment (Exhs. NEGC-JMS-1, at 12; AG-21-2). During the test year, NEG Appliance reported $2,974,250 in operating revenues and a net operating margin after direct expenses of $2,639,989 (Exh. AG-21-2, Att. B).

The Company proposes several adjustments to its cost of service to remove expenses incurred by NEGC for the benefit of NEG Appliance (Exhs. NEGC-JMS-1, at 35; NEGC-JMS-2, Sch. G-24). First, the Company removed labor, benefits, and payroll tax expenses that are chargeable to NEG Appliance for: (1) three company employees who are directly assigned to NEG Appliance; (2) other NEGC employees who charge time directly to NEG Appliance; (3) NEGC administrative and customer service employee costs allocable to NEG Appliance; and (4) TWE costs incurred by NEGC employees who perform work for NEG Appliance (Exh. NEGC-JMS-1, at 35; NEGC-JMS-2, Schs. G-4 through G-7 (Rev.)).[170]

Second, the Company allocates to NEG Appliance various overhead costs associated with the following categories: (1) customer related costs (e.g., billing, call center, postage,

[170] These costs are described in Sections V.A. and V.C., above.

and banking); (2) shared office space and storage space costs (e.g., rent, electricity, and gas); (3) depreciation and amortization expense, property taxes, and return on shared Company-owned property; (4) insurance expenses; and (5) telecommunications expenses (Exhs. NEGC-JMS-1, at 36; NEGC-JMS-2, Sch. G-24 (Rev)).). These costs are incurred initially by NEGC, which then allocates them to NEG Appliance through Account 922, Administrative Expenses Transferred (Exh. AG-1-57).

Whenever possible, NEGC allocates costs to NEG Appliance based on causal factors, such as number of customers, number of employees, and square footage (Exh. DPU-NEGC-3-19). For instance, customer-related costs, including phone costs for communicating with customers, are allocated on the basis of customer bills (Exh. DPU-NEGC-3-19). Costs associated with NEGC's Main Street office and warehouse are allocated based on the relative square footage used by NEG Appliance compared to the space used by the Company at each of these locations (Exh. DPU-NEGC-3-19). Other employee-related costs, such as depreciation on furniture and equipment, as well as workers' compensation insurance, are allocated based on the relative number of employees (Exh. DPU-NEGC-3-19). When a causal factor cannot be specifically identified, costs are allocated to NEG Appliance on the basis of a three-part factor consisting of net margin, expenses, and investment consistent with the method used by Southern Union to allocate management and administrative costs to its respective business units (Exh. NEGC-JMS-1, at 35-36; DPU-NEGC-3-19). NEGC represents that its allocation method is similar to the "modified Massachusetts formula"[171] used by Southern Union to allocate costs among its FERC-regulated operations (Exh. AG-10-7).[172]

During the test year, the Company allocated $342,084 in non-payroll-related costs to NEG Appliance through Account 922 (Exhs. NEGC-JMS-2, Sch. G-24 (Rev.); AG 1-57). In its initial filing, NEGC proposed to increase its allocation of overhead costs to NEG Appliance by $34,918, to $377,002 (Exh. NEGC JMS 2, Sch. G-24). During the proceedings, the Company proposed to revise the allocation factor for Other Customer Records & Collections Expense from an across-the-board 14.47 percent to an activity-specific range from zero to 19.79 percent, based on: (1) what NEGC considered to be a more detailed allocation approach; and (2) NEGC's determination that its initial allocator, which was based solely on customer bills, failed to recognize that NEG Appliance customers were billed for both appliance and gas service on the same bill (Exh. NEGC-REB-JMS-1, at 1; Tr. 8, at 1062-1066).

NEGC's non-payroll related activities and its respective revised allocation factors are outlined in the following table:

171 See Section V.G.1.b., above, for a general description of the modified Massachusetts formula.

172 Southern Union's FERC-regulated operations include PEPL, Sea Robin Pipeline Company LLC, Trunkline LNG Holdings, LLC, and its interest in Florida Gas (see Exhs. AG-1-2, Att. 1 at 6; AG-1-98, Att.).

Activity	Allocation Factor
Billing, Bill Printing, Postage	19.79%
Customer Call Center	4.17%
Payments and Payment Processing	4.17%
Collection Activities	4.17%
All Other	4.17%
Laundry	2.86%
Customer 800 Number and Online Bill Payment	4.17%
Insurance, Telecommunications, Depreciation	4.94%

(Exh. NEGC-REB-JMS-1; Tr. 8, at 1062).

The Company's revised allocators result in a total overall allocation of payroll-related expense to NEG Appliance of 2.27 percent, and a total overall allocation of non-payroll expense to NEG Appliance of 13.25 percent (see Exh. NEG-REB-JMS-1, at 1).[173] These allocation factors, applied to the respective expense categories, result in a total overhead cost allocation to NEG Appliance of $349,681, representing a decrease of $7,597 to the Company's test year allocation (Exhs. NEGC-JMS-2, Sch. G-24 (Rev.); NEGC-REB-JMS-1; Tr. 8, at 1066).

2. Attorney General's Proposal

The Attorney General notes that the amount of overhead costs that the Company transferred to NEG Appliance decreased from $662,000 in 2008 to $320,000 in 2009

173 The payroll allocator of 2.27 percent is derived by dividing the total allocated payroll of $12,010 by the total payroll of $529,553 (Exh. NEGC-REB-JMS-1, at 1). The non-payroll allocator of 13.25 percent is derived by dividing $305,808 in allocated non-payroll-related costs by total non-payroll costs of $2,307,729 (Exh. NEGC-REB-JMS-1, at 1).

(Exh. AG-DJE-1, at 13). According to the Attorney General, the Company failed to explain the decrease in allocation of expenses to NEG Appliance that occurred during this period (Exh. AG-DJE-1, at 14). Therefore, the Attorney General proposes to increase the Company's allocation of costs to NEG Appliance to the 2008 level of $666,000 (Exh. AG-DJE-1, at 15).

In addition, the Attorney General notes that NEGC's customer records and collections expense initial allocator attributes all activities related to customer records and collections solely to gas distribution operations, and thus gives appliance customers a "free ride" (Exh. AG-DJE-1, at 15). She proposes that where customer records and collections expenses are associated with customers who have both gas distribution service and appliance service, the expense should be allocated to both the gas distribution service and the appliance service, rather than just to the gas distribution service (Exh. AG-DJE-1, at 15).

3. Positions of the Parties

a. Attorney General

The Attorney General contends that the Company's initial billing, printing, and postage allocator of 14.47 percent, as well as its revised 4.17 percent allocator used for most other payroll-related expenses, are without merit and should be rejected (Attorney General Brief at 62-63; Attorney General Reply Brief at 13). According to the Attorney General, the Company's initial customer billing allocation method was flawed because accounts with both gas and appliance service were allocated exclusively to the Company (Attorney General Brief at 63).

Turning to the Company's proposed 4.17 percent allocation factor for most of NEG Appliances' other non-payroll related costs, the Attorney General contends that NEGC's proposed allocator is inappropriately based on total revenues (Attorney General Brief at 62-63). In support of her position, the Attorney General reasons that the Company's allocator includes gas cost revenues that are recovered through a pass-through mechanism, and are not indicative of cost causation (Attorney General Brief at 63). She maintains that a revenue-based allocator results in an "illogical" situation whereby NEGC's allocation of costs will depend on gas price variability (Attorney General Brief at 63; Attorney General Reply Brief at 12-13). The Attorney General argues that for accounts with gas and other services on the same bill, the allocation to NEG Appliance should be based on the method provided in Exhibit NEGC-AG-1-49, which results in a billing, printing, and postage allocation to NEG Appliance of 19.79 percent, and consequent reduction of $140,833 in expenses to be allocated to the Company (Attorney General Brief at 62-63, citing Tr. 9, at 1062-1063; RR-DPU-60; Attorney General Reply Brief at 13).

b. Company

The Company maintains that its revised cost allocation method for NEG Appliance addresses the Attorney General's initial concern that NEG Appliance customers were not being allocated an appropriate share of NEGC's expenses (Company Brief at 34-35). According to the Company, it has revised its cost allocation method to provide a more detailed and specific approach using cost causation principles that addresses the Attorney General's concerns regarding the use of a bill-based allocation factor (Company Brief at 34-35; Company Reply

Brief at 6). The Company argues that NEGC's revised cost allocation should be adopted because it addresses the Attorney General's concerns about proper cost causation relating to the allocation of customer bill-related costs, while simultaneously taking into consideration other appropriate factors in allocating costs that are not specifically bill related (Company Brief at 35). The Company claims that its revised approach results in a decrease in expenses allocated to NEG Appliance compared to NEGC's initial allocator (Company Reply Brief at 6, citing Exh. NEGC-REB-JMS-1, at 1; Tr. 8, at 1066).

NEGC argues that the Attorney General's proposed allocations are inappropriate and inconsistent with her own arguments regarding cost causation principles (Company Reply Brief at 7). NEGC contends that the Attorney General's objections to its revised allocation method are also misplaced because the Company's approach relies on net margins, versus gross revenues, as specifically sought by the Attorney General (Company Reply Brief at 6, citing RR-AG-24). The Company maintains that, to the extent the Department finds it appropriate to allocate costs to NEG Appliance on the basis of net margins, the evidence supports an overall reduction of $45,473 in the allocation of expenses to NEG Appliance (Company Reply Brief at 6). Therefore, the Company concludes that the Attorney General's arguments on this issue should be rejected (Company Reply Brief at 6).

4. Analysis and Findings

Because NEG Appliance is an affiliate of NEGC, the Department's goal is to ensure that there is no cross-subsidization between NEG Appliance and the Company and that costs incurred by NEGC for the benefit of NEG Appliance are properly allocated to NEG

Appliance. While the Department had previously accepted the Company's allocations to NEG Appliance, the Attorney General has contested several of the allocation factors, as well as the overall increase in costs being borne by NEGC's gas distribution operations. Moreover, NEGC has proposed to revise one of the allocation factors, resulting in a greater allocation of costs to NEGC. The Department addresses each of these issues below.

The Department has reviewed the Company's proposed allocators. NEGC proposes to disaggregate its payroll and non-payroll costs associated with billing, credit, and collection, and apply a series of activity-specifc allocators to these expense categories (Exh. NEGC-REB-JMS-1, at 1). These allocators are intended to replace the Company's originally proposed across-the-board allocator of 14.47 percent (Tr. 8, at 1062-1066). The payroll expense of supervisory staff involved in credit and collections, billing, and field services, is based on time spent on NEG Appliance's operations, while the Company's services supervisor's payroll expense has been allocated on the basis the proportion of warehouse operations used by NEG Appliance (Exh. NEGC-REB-JMS-1, at 1-4). Based on our review, we find that these allocators are more directly related to the underlying costs, and thus result in a more accurate measure of the costs associated with NEG Appliance's operations than through the use of an across-the-board allocator. The Department has also examined the proposed non-payroll allocator of 19.79 percent for costs related to billing, printing, and postage expenses. This allocator is based on billable premises (i.e., the sum of appliance service bills and one-half of bills where gas and appliances are billed jointly, divided by total bills issued) (Exhs. NEGC-REB-JMS-1, at 2; NEGC-AG-1-49 Supp., Att.; AG-3-20 Supp.). Out of

17,192 bills issued to customers receiving service from both the Company and NEG Appliance, 5,937 customers received a single bill for both NEGC and NEG Appliance, 5,589 NEGC customers are billed separately for gas service, and 5,666 NEG Appliance customers are billed separately for appliance service (Exh. NEGC-JMS-3, WP G-24.13). An additional 35,184 bills are issued to customers receiving service only from NEGC, and 2,403 bills are issued to customers who receive service only from NEG Appliance (Exh. NEGC-JMS-3, WP G-24.13). In view of this division of billing arrangements to customers served by both NEGC and NEG Appliance, the Department finds that an allocation of customer-related costs based on billable premises is more indicative of cost causation than an allocator based on the number of bills issued. Therefore, the Department approves the Company's proposed 19.79 percent allocator for billing, printing, and postage expenses.

The Company proposes to allocate to NEG Appliance 4.17 percent of expenses related to NEGC's: (1) call center; (2) payments and payment processing; (3) collections activities; (4) customer 800 telephone service; and (5) online bill paying services (Exh. NEGC-REB-JMS-1, at 1). For calendar year 2009, this allocator is based on NEG Appliance's adjusted total revenues relative to those of the Company (Exh. NEGC-REB-JMS-1, at 2). While the Attorney General is concerned that fluctuations in gas prices render the use of total revenues unreliable for cost allocation purposes, the Department is unpersuaded, without further evidence, that commodity cost fluctuations have a significant effect on the allocation of costs to NEG Appliance. Therefore, the Department declines to adopt the Attorney General's proposal, and accepts the Company's 4.17 percent allocator used to derive the billing, credit, and collection allocation.

The Company applies a general allocator of 4.94 percent to apportion certain types of insurance and telecommunication expenses, as well as depreciation expense, to NEG Appliance (Exh. NEGC-JMS-3, WP G-24). This general allocator is derived from the three-factor allocation method used to apportion management support costs from Southern Union, consisting of an equal weighting of (1) investment, (2) net margin, and (3) total capital and operating expenses (Exhs. NEGC-JMS-3, WP G-24.1, at 4; AG-10-22, Atts. A through C). The Department has applied a different allocation method to the Company's management support expense using a plant, net margin, and total operating expense allocator (see Section V.G.3.b., above). We find that this same allocator is appropriate to use as a general allocator to allocate insurance, telecommunication, and depreciation expenses to NEG Appliance. Consistent with this revised allocation method, the Department has recalculated the Company's general allocator using the Company's and NEG Appliance plants', net margin, and total operating expense data provided in Exhibit AG-DR-3, at 1. Based on this adjustment, the Department has derived a revised general allocator of 5.858 percent. Accordingly, the Department will use a general allocator of 5.858 percent to allocate insurance and telecommunications expense. Application of this revised general allocator to the Company's appliance allocation provided in Exhibit NEGC-JMS-2, Sch. G-24 (Revised) produce revised allocations to NEG Appliance of $13,427 in other insurance expense and $5,800 in general long-distance telephone and communications expense.

In addition to these O&M expense adjustments, the revised general allocator affects the allocation of depreciation expense to NEG Appliance. Based on the application of the revised general allocator of 5.858 percent, NEG Appliance's allocated portion of depreciation expense increases from $14,988 to $15,399. This adjustment of $411 has been incorporated in Schedule 3 of this Order.

Finally, the Company allocated $335 in property tax expense based on NEG Appliance's proportional use of NEGC's warehouse at 66 5th Street in Fall River (Exh. NEGC-JMS-3, WP G-24.1, at 1). The most recent quarterly property tax bill associated with this property is for $4,768, which corresponds to an annual property tax expense of $19,072 (RR-DPU-23, Att. C at 22). Using the 1.71 percent property tax allocator for NEG Appliances as derived in Section V.M., below, the Department finds that NEG Appliance's allocated portion of the property tax associated with this building is $326 (see Exh. NEGC-JMS-3, WP G-24.1; RR-DPU-23-C at 22, 32). This adjustment has been incorporated in Schedule 7 of this Order.

These increases, less the increases associated with depreciation and property tax expense, produce a total allocation to NEG Appliance of $330,454, representing a decrease of $11,360 to the test year allocation of $342,084. Because NEGC has proposed to reduce its test year cost of service by $7,597, the Department will reduce the Company's proposed cost of service by an additional $4,033.

O. Inflation Allowance

1. Introduction

NEGC proposed an inflation adjustment of $78,528 (Exh. NEGC-JMS-2, Sch. G-25). The Company used the gross domestic product implicit price deflator ("GDPIPD") to calculate the inflation allowance (Exhs. NEGC-JMS-1, at 36; NEGC-JMS-2, Sch. G-25). The Company applied the GDPIPD from the midpoint of the test year to the midpoint of the rate year, which resulted in a 1.96 percent inflation factor (Exh. NEGC-JMS-2, Sch. G-25). The Company multiplied the inflation factor by its residual O&M expenses of $3,992,420, thus producing an inflation adjustment of $78,528 (Exh. NEGC-JMS-2, Sch. G-25). The Company contends that its inflation adjustment complies with Department policy (Company Brief at 27, citing Exhs. NEGC-JMS-1, at 34; NEGC-JMS-2, Sch. G-25). No other party commented on the Company's proposed inflation allowance on brief.

2. Analysis and Findings

The inflation allowance recognizes that known inflationary pressures tend to affect a company's expenses in a manner that can be measured reasonably. D.T.E. 02-24/25, at 184; D.T.E. 01-56, at 71; D.T.E. 98-51, at 100-101; D.T.E. 96-50 (Phase I) at 112-113. 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. The Department permits utilities to increase their test year residual O&M expense by the projected GDPIPD from the midpoint of the test year to the midpoint of the rate year. D.P.U. 08-35, at 154-155;

D.T.E. 02-24/25, at 184; D.P.U. 95-40, at 64; D.P.U. 92-250, at 297-298. In order for the Department to allow a utility to recover an inflation adjustment, the utility must demonstrate that it has implemented cost containment measures. D.P.U. 09-30, at 285; D.P.U. 08-35, at 154; D.T.E. 02-24/25, at 184.

NEGC has undertaken a number of efforts to reduce the Company's O&M costs. With respect to health care, the Company has introduced a cost sharing method to its workforce that shares the total cost of health care with employees on an 80/20 percent company to employee cost basis (Exh. AG-1-52). Such cost sharing produces incentives for employees to use the least cost insurer. The Company has also incorporated a preferred provider arrangement into its health care administration agreement with its third-party administrator (Exh. AG-1-52). This arrangement provides a financial incentive for employees to utilize a medical provider that participates in an approved network, which helps control costs through network discounts (Exh. AG-1-52). In addition, the Company has implemented coverage for preventative services, designed to indentify medical conditions early in order to prevent more serious conditions (and higher costs) later (Exh. AG-1-52).

NEGC also contains costs associated with workers' compensation and auto and general liability insurance by utilizing an insurance broker whose fee is negotiated directly (RR-DPU-25). The current broker arrangement has been negotiated for a three-year period, which reduced the annual cost from the previous term (RR-DPU-25). Under the May 2010 union contract, NEGC also reduced the terms of its Company match to its 401(k) plan for certain union members, e.g., recent hires (compare Exh. AG-1-42, Att. A at 65 and Exh. AG-1-42, Att. B at 62).

Accordingly, we find that NEGC has implemented cost containment measures, and that the Company has calculated its proposed inflation allowance consistent with Department precedent. Therefore, the Department finds that an inflation allowance adjustment equal to the most recent forecast of GDPIPD for the appropriate period as proposed by NECG, applied to the Company's approved level of residual O&M expense, is proper in this case. As shown on Table 1, the resulting inflation allowance for NEGC is $78,251.[174]

[174] This amount is $277 less than the Company's proposal due to the Department's use of a composite inflation factor of 1.96 percent.

TABLE 1

Test Year O&M Expense per Books:		$29,064,311
Less:		
Payroll Expense		$7,512,174
Payroll Taxes		$643,981
Employee Benefits		$5,195,690
Transportation Clearing		$491,043
Contract Labor		$76,631
Interest on Customer Deposits		$7,389
Uncollectible Expense		$178,709
Postage Expense		$280,366
Management Support Cost Allocation		$2,018,346
RCS Expense		$63,099
Union Contract		$33,260
Professional Fees		$717,946
Supply Plan		$346,000
Insurance Premiums		$471,699
Self Insurance Deductible		$914,156
Rate Case Expense		$379,771
Rents and Leases		$70,699
Miscellaneous Interest		$16,242
Miscellaneous Other		$1,117,514
Depreciation		$3,747,606
Taxes Other Than on Income		$1,727
Property Taxes		$1,129,926
Applicance Company Allocations		($342,084)
		$25,071,890
O&M Expenses Subject to Inflation per Company:		$3,992,421
Less Department Adjustments:		$0
Residual O&M Expense:		$3,992,421
Projected Inflation Rate:		1.96%
Inflation Allowance:		$78,251
Company Proposal:		$78,528
Difference:		($277)

P. Attorney General Consultant Expenses

1. Introduction

Pursuant to G.L. c. 12, § 11E(b), the Attorney General may retain experts or other consultants to assist her in Department proceedings involving rates, charges, prices, and tariffs of an electric, gas, generation, or transmission company subject to the Department's jurisdiction. The cost of retaining such experts or consultants cannot exceed $150,000 per proceeding unless otherwise approved by the Department based upon exigent circumstances. G.L. c. 12, § 11E(b). All reasonable and proper expenses for such experts or consultants are to be borne by the affected company and are recoverable through the company's rates without further approval by the Department. G.L. c. 12, § 11E(b).

In this case, the Department authorized the Attorney General to spend up to $150,000 for outside experts and consultants. D.P.U. 10-114, Order on Attorney General's Notice of Retention of Experts and Consultants at 4-5 (October 27, 2010). NEGC reports that the fees related to the Attorney General's experts and consultants total $115,965, as of February 17, 2011, and additional fees are expected to be incurred (Exh. DPU-NEGC-5-8(A) Supp.).

2. Company's Proposal

NEGC proposes to include a factor in its LDAC to recover the Attorney General's consultant expenses ("AGCE") (Exhs. NEGC-JDS-1-15, at 11-12; DPU-NEGC-1-19). The factor is designed to recover the AGCE from all customers based on annual throughput (Exhs. NEGC-JDS-1-15, at 11-12; DPU-NEGC-1-19, at 1). NEGC proposes to apply the Bank of America prime lending rate on unrecovered balances for the AGCE, consistent with the rate used for all LDAC reconciling mechanisms (Exhs. NEGC-JDS-1-15, at 25; DPU-NEGC-1-20). The Company states that information pertaining to these expenses will be filed with the Department consistent with the filing requirements of all costs and revenue information included in the LDAC (Exhs. NEGC-JDS-1-15, at 26; DPU-NEGC-1-19, at 1). No party commented on NEGC's proposed treatment of the Attorney General's consulting expenses on brief.

3. Analysis and Findings

In authorizing the Attorney General to spend up to $150,000 for outside experts and consultants in this proceeding, the Department did not address the merits of NEGC's proposed recovery mechanism, stating that this issue would be addressed during the course of the instant rate proceeding. D.P.U. 10-114, Order on Attorney General's Notice of Retention of Experts and Consultants at 4 (October 27, 2010). The Department has broad discretion in selecting an appropriate rate recovery mechanism. See American Hoechest Corp. v. Department of Public Utilities, 379 Mass. 408, 411-413 (1980) (the Department is free to select or reject particular method of regulation as long as choice not confiscatory or otherwise illegal).

General Laws c. 12, § 11E(b) provides that all reasonable and proper expenses for the Attorney General's experts or consultants are recoverable through a company's rates without further approval by the Department. NEGC's proposed recovery mechanism achieves this result. The LDAC allows NEGC to recover, on a fully reconciling basis, costs that have been determined to be distribution-related but, because they are reconciling, are more appropriately recovered outside base rates (see Exh. NEGC-JDS-1-15, at 1).[175] The Company's LDAC is applicable to all firm customers, i.e., both sales and transportation customers. (Exh. NEGC-JDS-1-15, at 1). As such, we conclude that NEGC's proposal to recover the AGCE through its LDAC is reasonable and appropriate and, thereby, approved.[176]

VI. CAPITAL STRUCTURE AND RATE OF RETURN

A. Introduction

The Company proposes a 9.08 percent[177] 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 (Exhs. NEGC-FJH at 2-3; NEGC-FJH-1, Sch. 1, at 1). In addition, the Company presents a separate WACC of 9.21 percent as an alternative if its proposed RDM is not approved (Exh. NEGC-FJH at 2-3). These rates are based on a proposed capital structure of 49.83 percent long-term debt and 50.17 percent common equity (Exhs. NEGC-FJH at 2-3; NEGC-FJH-1, Sch. 1, at 1). The Company proposes a cost of long-term debt of 7.50 percent and a rate of return on common equity ("ROE") of

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175 The Department has approved recovery through the LDAC of the Attorney General's expenses for consultants and experts pursuant to G.L. c. 12, § 11E(b) in D.P.U. 10-55, at 426 and D.P.U. 09-30, at 408.

176 As the Department gains more experience with these types of expenses, we will consider whether these expenses are better recovered through base rates instead of in a reconciling mechanism.

177 The Company transposed the weighted long-term debt figure in the approval column of the table it provided; that is, based on the resulting calculation, the figure is intended to be 3.74 percent rather than 3.47 percent (Exh. NEGC-FJH, at 3).

10.65 percent, or 10.90 percent if the RDM is not approved (Exhs. NEGC-FJH at 2-3, 5, 8, 64-66; NEGC-FJH-1, Sch. 1, at 1-2).

In determining its proposed ROE, the Company applies the discounted cash flow model ("DCF model"), the capital asset pricing model ("CAPM"), and the risk premium model ("RPM") using the market and financial data developed from a proxy group of nine gas distribution companies ("utility proxy group") (Exhs. NEGC-FJH at 4, 11-12; NEGC-FJH-1, Sch. 4, at 1, Sch. 8, Sch. 9, Sch. 10, Sch. 11, at 1-10, Sch. 12, at 1-2, 9, Sch. 15, at 1-3, Sch. 16, at 1, Sch. 18, at 2). The Company also applies the same three market-based models (DCF model, CAPM, and RPM) to a proxy group of domestic, non-price regulated companies with risk characteristics similar to that of the utility proxy group in its analysis of the comparable earnings method ("CEM") (Exhs. NEGC-FJH at 6, 50-56; NEGC-FJH-1, Sch. 16, at 1-3, Sch. 17, at 1-7).

The components of the Company's proposal, including the rate of return impact of the Company's proposed RDM, are discussed below. In addition, we discuss the Attorney General's recommendations, as well as her revisions to that recommendation offered on brief.

B. Capital Structure

1. Company's Proposal

NEGC relies on the capital structure of Southern Union as of December 31, 2009, as the starting basis of its proposed capitalization (Exh. NEGC-FJH at 3). As of the end of the test year, Southern Union's capitalization consisted of $3,561,736,233 in long-term debt,

$115,000,325 in preferred equity, and $2,354,946,000 in common equity (Exhs. NEGC-FJH at 2-3, 14; NEGC-FJH-1, Sch. 1, at 1, Sch. 5).

The Company proposes to adjust Southern Union's capital structure to eliminate maturing debt, as well as nonrecourse debt and equity issuances used exclusively to finance the acquisitions of PEPL and Cross Country Energy, LLC ("CCE") (Exhs. NEGC-FJH at 3, 14; NEGC-FJH-1, at Sch. 5). The proposed adjustments to long-term debt include (1) a deduction of $100,000,000 to recognize the maturity of senior notes on February 16, 2010; (2) a deduction of $2,024,746,233 to recognize the exclusion of PEPL debt; and (3) a deduction of $7,725,000 to recognize the exclusion of notes payable secured by the property of PEI and nonrecourse[178] to Southern Union (Exhs. NEGC-FJH at 14-15; NEGC-FJH-1, at Sch. 5). The Company's remaining long-term debt of $1,429,265,000, consisting of senior notes, subordinated notes, and a term note, represents NEGC's proposed debt for rate making purposes (Exh. NEGC-FJH-1, at Sch. 5).

The Company eliminates fully the $115,000,325 in preferred equity from its representative portion of Southern Union's capital structure to recognize the July 30, 2010 redemption of these securities (Exh. NEGC-FJH-1, Sch. 5).[179] The Company reduced its common equity balance to recognize (1) $5,217,042 in unamortized issuance costs associated

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[178] In this circumstance, nonrecourse means that, although the notes payable are secured by the assets of Southern Union (property of PEI), Southern Union is not liable for the debt (i.e., the lender has no recourse against Southern Union).

[179] The Company filed SEC Form 8-K on June 30, 2010, regarding the pending redemption of this preferred equity (Exh. NEGC-FJH-1, Sch. 5; Tr. 3, at 326).

with the PEPL debt, the PEI debt, and the matured senior notes; and (2) the elimination of $910,428,774 in common equity issuances attributable exclusively to the acquisitions of PEPL and CCE (Exhs. NEGC-FJH at 15; NEGC-FJH-1, Sch. 5). The remaining common equity balance of $1,439,300,184 represents NEGC's proposed equity for ratemaking purposes (Exh. NEGC-FJH-1, Sch. 5). Based on these adjustments, NEGC's proposed capital structure consists of 49.83 percent long-term debt and 50.17 percent common equity (Exhs. NEGC-FJH at 2-3, 6, 16; NEGC-FJH-1, Sch. 1, at 1, Sch. 5).

2. Attorney General's Proposal

The Attorney General also relies on Southern Union's actual December 31, 2009, capital structure for her proposed capital structure ratios (Exhs. AG-JRW-1, at 13-14; AG-JRW-5, at 3). The Attorney General proposes a capital structure consisting of $3,511,167,301 in long-term debt and $2,358,031,420 in common equity (Exh. AG-JRW-5, at 3). The Attorney General states that this capital structure corresponds to 59.82 percent long-term debt and 40.18 percent common equity (Exhs. AG-JRW-1, at 13-14; AG-JRW-5, at 3).

3. Positions of the Parties

a. Attorney General

The Attorney General claims that NEGC has only $25 million in equity on its balance sheet as of the end of 2009 and that it is funded primarily by intercompany payables (Attorney General Brief at 40, citing Exh. AG-JRW-1, at 13). Further, the Attorney General states that as an operating division of Southern Union, NEGC participates in Southern Union's cash management program through which excess funds are transferred to Southern Union, and shortfalls are funded by Southern Union (Attorney General Brief at 40, citing Exh. AG-JRW-1, at 13). The Attorney General argues that Southern Union has operated for years with a common equity ratio in the range of 35 to 40 percent (Attorney General Brief at 41). She points to the average quarterly common equity ratio of 39.15 percent for the year 2009 (Attorney General Brief at 41, citing Exh. AG-JRW-5, at 1). For these reasons, the Attorney General argues that the appropriate capital structure is the capitalization of Southern Union, unadjusted for nonrecourse debt on equity used to finance its acquisitions, or 40.17 percent common equity[180] and 59.83 percent long-term debt (Attorney General Brief at 40, citing Exh. AG-JRW-1, at 13-14).

The Attorney General claims that NEGC used only selective debt issues of Southern Union in its capital structure proposal (Attorney General Brief at 41, citing Exh. NEGC-FJH-1, Sch. 5; Attorney General Reply Brief at 6). The Attorney General maintains that although the excluded PEPL and PEI debt is nonrecourse to Southern Union, this debt has nonetheless been incorporated into Southern Union's reported capitalization and has been relied upon by rating agencies in determining Southern Union's bond ratings (Attorney General Reply Brief at 7-8, citing Tr. 6, at 705-706). In support of her contention, the Attorney General points out that regardless of the presence of nonrecourse debt held by a subsidiary company, the bond rating for both the parent company and the subsidiary will be the

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180 The Attorney General accounts for the lower common equity ratio of Southern Union relative to other gas companies by applying a 50 basis point upward adjustment to her recommended ROE (Attorney General Brief at 40, citing Exh. AG-JRW-1, at 47).

same, and their associated costs of debt will be similar (Attorney General Reply Brief at 8, citing Tr. 6, at 711-712).

b. Company

The Company argues that, consistent with the decision in D.P.U. 08-35, it used the actual capital structure of Southern Union as of December 31, 2009, as a basis for developing the proposed revenue requirement (Company Brief at 41, citing Exh. NEGC-FJH at 14; Tr. 3, at 338). NEGC also argues that all of the ratemaking adjustments that the Company made to Southern Union's actual capital structure are consistent with Department precedent (Company Brief at 42).

The Company contends that the Attorney General's use of an unadjusted capital structure is not consistent with ratemaking principles or Department precedent (Company Brief at 55). According to NEGC, the Attorney General's adjustment to ROE based on the Company's capitalization is irrelevant to the issue of whether to include nonrecourse debt in the Company's capitalization (Company Reply Brief at 25). The Company maintains that the Attorney General's arguments concerning bond ratings are also irrelevant, because the excluded debt cannot be used to finance the operations of any entity other than PEPL, as the Attorney General concedes (Company Brief at 56, citing Tr. 6, at 712; Company Reply Brief at 25). NEGC contends that, unlike the situation faced by the Department in D.P.U. 08-35, there is no difficulty in separating PEPL's nonrecourse debt from Southern Union's other debt issues, and that the Department has previously excluded debt that was unrelated to a utility's regulated operations from capitalization (Company Reply Brief at 25, citing D.P.U. 10-55, at 473, 475).

The Company claims that the adjusted Southern Union capital structure, with a common equity ratio of 50.17 percent, is also consistent with the utility proxy group's equity-to-total-capital ratio of 52.37 percent (Company Brief at 43, citing Exh. NEGC-FJH at 16). NEGC argues that its proposed, adjusted Southern Union capital structure is the most consistent with: (1) Department precedent in D.P.U. 08-35, which, the Company states, requires the use of Southern Union's capital structure; (2) Department precedent in D.P.U. 10-55, which, the Company states, requires the exclusion of acquisition debt from a capital structure if it does not support or is in any way associated with the rate base of the utility; and (3) Federal Power Commission v. Hope Natural Gas Company, 320 U.S. 591, 603 (1944) ("Hope"), which NEGC asserts requires that the Company's returns be commensurate with the returns of other gas companies (Company Brief at 57).

NEGC claims that the Department's decision to apply Southern Union's capital structure to NEGC's regulated utility operations has been a significant factor in the Company's inability to realize a sufficient return to stay out of a rate case (Company Brief at 42). The Company goes on to argue that the Department should utilize a capital structure for ratemaking purposes that is adequate and appropriate to support utility operations so that the Company has, at least, some opportunity to avoid such frequent rate cases (Company Brief at 42).

4. Analysis and Findings

A company's capital structure typically consists of long-term debt, preferred stock, and common equity. D.P.U. 08-35, at 184; D.T.E. 05-27, at 269; D.T.E. 03-40, at 319; D.T.E. 01-56, at 97; D.T.E. 01-42, at 17-18. The ratio of each capital structure component to the total capital structure is used to weight the cost (or return) of each capital structure component to derive a WACC. The WACC is used to determine the return on rate base for calculating the appropriate debt service and capital costs for the company to be included in its revenue requirements. D.P.U. 07-71, at 122; D.T.E. 03-40, at 319; D.T.E. 01-42, at 18; D.P.U. 86-149, at 5.

The Department will normally accept a utility's test-year-end capital structure, allowing for known and measurable changes, unless the capital structure deviates substantially from sound utility practice. D.T.E. 03-40, at 319; D.P.U. 1360, at 26-27; Blackstone Gas Company, D.P.U. 1135, at 4 (1982). Adjustments to test-year-end capitalization to recognize redemptions, retirements, or issuances of new debt or equity are allowed, provided that they are known and measurable and the proposed issuance or retirement of securities has actually taken place by the date of the Order. D.T.E. 03-40, at 323. In reviewing and applying utility company capital structures, the Department seeks to protect ratepayers from the effect of excessive rates of return. D.T.E. 03-40, at 319; Assabet Water Company, D.P.U. 1415, at 11 (1983); see Mystic Valley Gas Company v. Department of Public Utilities, 359 Mass. 420, 430 n.14 (1971).

In its prior directive to the Company, the Department utilized Southern Union's actual capital structure as of the test year end. See D.P.U. 08-35, at 189-191. The Company followed that directive in the instant case, and we find its use of Southern Union's actual capital structure as of December 31, 2009, is appropriate as the starting basis to determine NEGC's capitalization.

NEGC's removal of $100,000,000 in senior notes matured on February 16, 2010, is known and measurable and, thus, consistent with Department procedure. D.P.U. 90-121, at 157. Turning to the Company's exclusion of $2,024,746,233 in PEPL debt and $7,725,000 in PEI debt, PEPL and PEI are wholly owned subsidiaries of Southern Union, whose debt instruments are nonrecourse to Southern Union (Exh. NEGC-FJH at 3, 14-15). Thus, this debt is only used to finance the operations of PEPL and PEI, and are not available to finance NEGC's rate base (Exh. NEGC-FJH at 3, 14; Tr. 6, at 704-706, 712). While the Company is indisputably a division of Southern Union, we fail to see how either the combined nature of Southern Union and NEGC or Southern Union's cash management program is relevant to the issue of whether the PEPL and PEI debt should be included in NEGC's capitalization.[181] Similarly, the Department considers the Attorney General's proposed 50 basis point increase to her ROE calculation to account for her lower common equity ratio to be immaterial to the issue

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[181] The fact that a regulated utility's financial reports may include data associated with a subsidiary is not dispositive of whether the securities of the subsidiary should be included in the parent's capitalization for ratemaking purposes. See Western Massachusetts Electric Company, D.T.E. 05-9, at 11 n.9 (2005).

of the appropriate capital structure for NEGC. The Attorney General's 50 basis point ROE adjustment is addressed in Section VI.E.7, below.

In the Company's previous rate case, the Department relied on the actual capital structure of Southern Union on the basis that we were unable to distinguish the financing of NEGC's operations from that of the rest of Southern Union. D.P.U. 08-35, at 187. The Department, however, has previously excluded debt that was unrelated to a utility's operations when determining that company's capital structure for ratemaking purposes. D.P.U. 10-55, at 473, 475; D.T.E. 03-40, at 322.[182] In those cases, the Department determined that the debt instruments at issue related to the push-down of acquisition premiums resulting from KeySpan Corporation's acquisition of Boston Gas Company and Colonial Gas Company. D.P.U. 10-55, at 475; D.T.E. 03-40, at 322-323. The Department further found that these debt issuances were unrelated to utility operations and that their inclusion in capitalization would result in a significant disparity between capitalization and rate base. D.P.U. 10-55, at 475; D.T.E. 03-40, at 322-323.

In this case, the Company has identified the debt and equity associated with the acquisitions of PEPL and PEI (Exhs. NEGC-FJH at 14-15; NEGC-FJH-5). Because these

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[182] In recognition of the distinct characteristics of nonrecourse-type debt, the Department has excluded from capitalization securitization bonds issued pursuant to G.L. c. 164, § 1H that are used to finance electric company transition obligations. Western Massachusetts Electric Company, D.P.U. 05-9, at 4 n.3 (2005); Western Massachusetts Electric Company, D.T.E. 02-49, at 4 n.5, 10-11 (2003).

entities operate as wholly owned subsidiaries of Southern Union[183] and are financed through nonrecourse debt, the Department finds that the debt issuances are appropriately excluded from the Company's capitalization for ratemaking purposes. These adjustments result in a debt capitalization of $1,429,265,000.

We also accept NEGC's removal of the entire balance of $115,000,325 in preferred equity due to its redemption on July 30, 2010, as a known and measurable change. D.P.U. 03-40, at 323. Therefore, NEGC's capitalization will include no preferred equity.

NEGC adjusted Southern Union's actual equity capitalization by first excluding the unamortized issuance costs of $5,217,042 attributable to the PEPL and PEI debt and the matured notes (Exh. NEGC-FJH-1, Sch. 5, at n.5). The Company then reduced the equity further by the equity issuances attributable to PEPL and CCE of $338,832,000 and $571,596,774, respectively (Exh. NEGC-FJH-1, Sch. 5, at n.5). Consistent with our decision to exclude the nonrecourse debt from NEGC's capitalization, the Department approves of these adjustments.

These adjustments result in an equity capitalization of $1,439,300,184 and a debt capitalization of $1,429,265,000, and produce an equity-to-total capitalization ratio of 50.17 percent. The Department finds that this capitalization is within the bounds of sound utility practice.

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183 By contrast, NEGC operates as a division as part of Southern Union's corporate retail utility business.

C. Cost of Debt

1. Company's Proposal

The Company proposes a cost rate for long-term debt of 7.50 percent (Exh. NEGC-FJH at 16). NEGC's calculation of its rate begins by multiplying the December 31, 2009 balance of each issue of long-term debt, excluding the nonrecourse debt and $100,000,000 in matured debt, by respective coupon rate, producing the annual interest expense for each issue (Exh. NEGC-FJH-1, Sch. 6). The Company then determined the effective cost rate for each issue by adding the annual interest to the amortization of issuance costs, and dividing that figure by the outstanding debt less unamortized issuance costs (Exh. NEGC-FJH-1, Sch. 6).[184] The Company's calculations produced $102,876,940 of annual interest, plus $1,871,473 of amortized issuance costs, $1,429,265,000 of outstanding debt, and $31,810,938 of unamortized issuance costs (Exh. NEGC-FJH-1, Sch. 6). The effective rates for each debt issuance, weighted by the December 31, 2009 balances for each debt issue, resulted in an effective overall cost of debt of 7.5 percent (Exhs. NEGC-FJH at 16; NEGC-FJH-1, Sch. 6).

2. Attorney General's Proposal

The Attorney General proposes a cost rate of long-term debt of 5.728 percent for the Company associated with her debt ratio of 59.82 percent (Exhs. AG-JRW-1, at 13-14,

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184 The notes and column titles for the Company's exhibit give the calculation as: Effective Cost Rate = (Annual Interest + Amortized Issuance Cost) ÷ (Outstanding Debt at 12/31/09 + Unamortized Issuance Cost), or ($102,876,940+$1,871,473)÷($1,429,265,000+-$31,810,938) (Exh. NEGC-FJH-1, Sch. 6, at n.2).

AG-JRW-5, at 1, 3). In addition to the issuances included by the Company in its cost of debt calculations, the Attorney General includes the senior notes maturing on February 16, 2010, and the PEPL debt of $2,024,746,233 (Exh. AG-JRW-5, at 3, citing Exh. AG-4-1 (FJH), Att. A at WP Emb Costs). The Attorney General presents her cost of debt calculations as the sum of the annual interest on all debt, including nonrecourse debt, of $197,674,444 and the amortized issuance costs of $3,431,993, divided by the sum of: (1) the outstanding debt of $3,551,461,233; and (2) FERC account 257, unamortized premiums of $1,474,411, less the sum of (3) the FERC account 181, unamortized issuance costs of $30,248,824; and (4) the FERC account 189, unamortized issuance costs of $11,519,520 (Exh. AG-JRW-5, at 3).

3. Positions of the Parties

a. Attorney General

The Attorney General criticizes the Company for its use of "selective" debt issuances of Southern Union to derive its proposed cost of debt (Attorney General Brief at 41, citing Exh. NEGC-FJH-1, Sch. 5). In contrast, she notes that she has employed Southern Union's actual long-term debt cost rate as of December 31, 2009, resulting in the disparity between the parties' recommended debt cost rates (Attorney General Brief at 41).

b. Company

The Company argues that its long-term debt cost rate is consistent with the adjusted capital structure of Southern Union (Company Brief at 43). NEGC also argues that its proposed long-term debt is consistent with Department precedent in that it reflects the actual debt included in the Company's proposed capital structure (Company Brief at 43, citing Exh. NEGC-FJH at 16).

4. 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.T.E. 01-56, at 99; D.P.U. 90-121, at 160. The Department has found that 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; Boston Edison Company, D.P.U. 86-71, at 12 (1986).

While NEGC's proposed cost of debt appropriately considers amortized issuance costs, the Company has both added issuance costs to its interest expense and deducted unamortized issuance costs from its outstanding debt balance (Exh. NEGC-FJH-1, Sch. 6, at n.2). By reducing its outstanding debt balance by unamortized issuance costs, the Company's proposed cost of debt serves to over-collect its associated issuance costs. See D.P.U. 90-121, at 160-161; D.P.U. 86-71, at 12.[185] Therefore, the Department rejects the Company's cost of long-term debt.

185 Unamortized debt issuance costs should not offset long-term debt balances. The Unamortized Debt Expense Account is not a valuation account on the debt, but rather essentially a prepaid item.

With regard to the Attorney General's inclusion of FERC accounts 181, 189, and 257, in her cost of debt calculations, FERC's definition of these accounts corresponds to Account 181, Unamortized Debt Expense; Account 435, Miscellaneous Debits to Surplus; and Account 434, Miscellaneous Credits to Surplus; respectively, in the Department's Uniform System of Accounts for Gas Companies. Uniform System of Accounts For Gas Companies, 220 C.M.R. § 50.00 et seq., Income Accounts.[186] While these balance sheet entries are integral to the completeness of the Company's accounting records, the Department's 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, as opposed to the face value less various unamortized balances. See D.P.U. 10-70, at 244; D.P.U. 95-40, at 80-81, 177; D.P.U. 90-121, at 153, 275. By reducing the outstanding debt balance by these amounts, the Attorney General's calculation artificially reduces the Company's effective cost of debt. The Attorney General has not presented any new evidence or argument to support a departure from established Department

[186] The following excerpts define each of the FERC accounts in question: (1) Account 181, Unamortized Debt Expense, "shall include expenses related to the issuance or assumption of debt securities. Amounts recorded in this account shall be amortized over the life of each respective issue under a plan which will distribute the amount equitably over the life of the security;" (2) Account 189, Unamortized Loss on Reacquired Debt, "shall include the losses on long-term debt reacquired or redeemed. The amounts in this account shall be amortized in accordance with General Instruction 17;" and (3) Account 257, Unamortized Gain on Reacquired Debt, "shall include the amounts of discount realized upon reacquisition or redemption of long-term debt. The amounts in this account shall be amortized in accordance with General Instruction 17." 18 C.F.R. Pt. 101, Balance Sheet Chart of Accounts, Deferred Debits; Liabilities and Other Credits.

practice. Therefore, the Department declines to adopt the Attorney General's proposed calculation of NEGC's cost of debt.

The Department finds that the appropriate cost of long-term debt for NEGC is 7.33 percent, not 7.50 percent as the Company calculates. We arrive at this figure by dividing the sum of NEGC's annual cost of debt and its amortization of issuance costs of $104,748,413 by Southern Union's adjusted outstanding debt of $1,429,265,000 (Exh. NEGC-FJH-1, Sch. 6). Therefore, the Department will apply a cost of long-term debt of 7.33 percent.

D. Proxy Groups

1. Description of the Company's Proxy Group

NEGC presents its cost of equity analysis utilizing the capitalization and financial statistics of a proxy group of nine gas distribution companies (Exh. NEGC-FJH at 11-12). The Company selected its utility proxy group based on the following eight criteria. The selected companies: (1) are included in Value Line Investment Survey's ("Value Line") Standard Edition Natural Gas Utility Group; (2) have five years of historical financial data ending with the year 2009; (3) have positive Value Line five-year projections of growth in dividends per share ("DPS"); (4) have positive five-year projected growth rates in earnings per share ("EPS") and/or positive projected growth rates in EPS from Thompson Reuters ("Reuters") or Zack's Investment Service ("Zack's"); (5) have a Value Line beta; (6) have not cut or omitted their cash common stock dividend during the five calendar years ending 2009; (7) derived 60 percent or more of their net operating income and assets from regulated gas operations; and (8) have not publicly announced any merger or acquisition activity (Exh. NEGC-FJH at 11-12). The Company's proxy group consists of: (1) AGL Resources, Inc.; (2) Atmos Energy Corporation; (3) Laclede Group, Inc.; (4) New Jersey Resources Corp.; (5) Northwest Natural Gas Co.; (6) Piedmont Natural Gas Co., Inc.; (7) South Jersey Industries, Inc.; (8) Southwest Gas Corporation; and (9) WGL Holdings, Inc. (Exh. NEGC-FJH-1, Sch. 3, at 2).

2. Description of the Attorney General's Proxy Group

The Attorney General also presents a proxy group consisting of nine publicly held gas distribution companies which she terms the "Gas Proxy Group" (Exh. AG-JRW-1, at 11). In selecting the nine companies for her group, the Attorney General set four criteria (Exh. AG-JRW-1, at 11-12). The selected companies must: (1) be listed as a natural gas distribution, transmission, and/or integrated gas company in AUS Utility Reports; (2) be listed as a natural gas utility in the Standard Edition of Value Line; (3) receive at least 50 percent of revenues from regulated gas operations; and (4) have an investment grade bond rating by Moody's Investors Service, Inc. ("Moody's") and Standard & Poor's Financial Services, LLC ("Standard & Poor's") (Exhs. AG-JRW-1, at 12; AG-JRW-4, at 1). The Gas Proxy Group consists of: (1) AGL Resources, Inc.; (2) Atmos Energy Corporation; (3) Laclede Group, Inc.; (4) NICOR, Inc.; (5) Northwest Natural Gas Co.; (6) Piedmont Natural Gas Co., Inc.; (7) South Jersey Industries, Inc.; (8) Southwest Gas Corporation; and (9) WGL Holdings, Inc. (Exhs. AG-JRW-1, at 12; AG-JRW-4, at 1). The Attorney General adds that the Gas Proxy Group receives 68 percent of its revenues from regulated gas operations and has an 'A' bond rating from Standard & Poor's (Exh. AG-JRW at 12).

3. Positions of the Parties

a. Attorney General

The Attorney General notes that the two proxy groups proposed here are virtually identical (Attorney General Brief at 42). She points out that the two exceptions to the similarity of the parties' proxy groups are that NEGC excluded NICOR from its proxy group due to a zero percent projected dividend growth rate, and that she excluded New Jersey Resources from her Gas Proxy Group due to its low percentage of regulated gas revenues of 37 percent (Attorney General Brief at 42, citing Exh. NEGC-FJH at 54).

b. Company

NEGC states that each company in its utility proxy group has at least 60 percent of its net operating income and assets from regulated gas operations (Company Brief at 48, citing Exh. NEGC-FJH at 12). The Company further explains that because the utilities in its utility proxy group have the vast majority of their business enterprises devoted to the regulated gas distribution business, the ROE resulting from an analysis of its proxy group is appropriate under a standard of comparability (Company Brief at 48). The Company argues that the Attorney General is mistaken in the reasons for excluding New Jersey Resources from her Gas Proxy Group because New Jersey Resources has at least 60 percent of its net operating income and assets from regulated gas operations (Company Brief at 58, citing Exh. NEGC-FJH at 12).

4. Analysis and Findings

The Department has accepted the use of a proxy group of companies for evaluation of a cost of equity analysis when a distribution company does not have a common stock that is publicly traded. See D.P.U. 08-35, at 176-177; D.T.E. 99-118, at 80-82; D.P.U. 92-78, at 95-96. 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 parties, we recognize that it is neither necessary nor possible to find a group that matches the Company in every detail. See 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 utilities will be in the proxy group, and then provides sufficient financial and operating data to discern the investment risk of the Company as opposed to the proxy group. See D.T.E. 99-118, at 80; D.P.U. 87-59, at 68; D.P.U. 1100, at 135-136.

The Department expects diligence on the part of expert witnesses in assembling proxy groups that will produce statistically reliable analyses required to determine a fair rate of return for the Company. See D.P.U. 10-55, at 480-482. Overly exclusive selection criteria may affect the statistical reliability of a proxy group, especially if such screening criteria result in a limited number of companies in the proxy group. The Department expects parties to limit criteria to the extent necessary and to develop a larger as opposed to a narrower proxy group. See D.P.U. 10-55, at 481-482. To the extent that a particular company's characteristics differ from those of the others in a proxy group, those differences should be identified in sufficient detail to enable a reviewer to discern any effects on investment risk.

We find that NEGC 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 as opposed to the members of the proxy groups. D.P.U. 09-30, at 307. Therefore, the Department will rely on those proxy groups to determine the Company's required cost of equity. Our acceptance of these groups notwithstanding, we raise two factors that we will also take into consideration in determining the appropriate ROE for the Company. First, NEGC's proposed decoupling mechanism is but one form of a wide range of revenue recovery mechanisms used by members of the parties' proxy groups that the financial market and regulatory community consider to be revenue stabilization mechanisms. D.P.U. 10-55, at 482; D.P.U. 09-39, at 348; D.P.U. 09-30, at 308; see also D.P.U. 07-50-A at 72. Second, some of the holding companies in the proxy groups are also involved in non-regulated businesses beyond gas distribution activities, potentially making these companies more risky, all else being equal, and in turn, more profitable than the Company. D.P.U. 09-39, at 350; D.P.U. 09-30, at 308; D.P.U. 07-71, at 135. Therefore, while we accept the parties' proxy groups as a basis for cost of capital proposals, we will also consider the particular characteristics of the Company as opposed to the proxy groups when determining the appropriate ROE.

E. Return on Equity

1. Introduction

a. Company's Proposal

NEGC proposes to apply a 10.65 percent ROE for the Company based on the results of three equity cost models: the DCF model, CAPM, and the RPM (Exhs. NEGC-FJH at 6, 17;

NEGC-FJH-1, Sch. 1, at 2). The Company also applied the CEM approach, stating that the U.S. Supreme Court did not require in the Bluefield Water Works Improvement Company v. Public Service Commission, 262 U.S. 679 (1922) ("Bluefield") and Hope cases that the companies of comparable risk had to be utilities (Exh. NEGC-FJH at 50). The Company states that no one individual method provides the necessary level of precision for determining a fair return, but that each method provides useful evidence to facilitate the exercise of an informed judgment (Exh. NEGC-FJH at 21, citing Roger A. Morin, The Regulation of Public Utilities – Theory and Practice, PUBLIC UTILITIES REPORTS, INC., 1993, at 428, 430-431). Based on its analyses, NEGC determined ROEs of 9.32 percent, 10.18 percent, 10.41 percent, and 11.04 percent using the DCF model, CAPM, RPM, and CEM respectively (Exh. NEGC-FJH-1, Sch. 1, at 2).

b. Attorney General's Proposal

The Attorney General proposes a base ROE of 8.50 percent supported by her ROE calculations of 8.50 percent with her DCF model analysis and 7.30 percent with her CAPM analysis (Exhs. AG-JRW-1, at 46-47; AG-JRW-1, at 1; AG-JRW-10, at 1; AG-JRW-11, at 1). The Attorney General's recommended cost of equity is based on a range of what she views as appropriate ROEs from 7.5 percent to 8.5 percent; because she places more weight on the DCF model, she choose the high end of that range at 8.5 percent (Exh. AG-JRW at 47). To account for the risk differential between a typical gas company and Southern Union, the Attorney General adds 50 basis points to her equity cost rate of 8.50 percent, bringing her recommended ROE up to 9.00 percent for NEGC (Exh. AG-JRW-1, at 47). The Attorney

General explains that this risk differential is due to her use of Southern Union's common equity ratio of approximately 40 percent as opposed to the typical 50 percent for gas distribution companies (Exh. AG-JRW-1, at 47).

2. Positions of the Parties

a. Attorney General

On brief, the Attorney General reduced her recommended ROE from 9.0 percent to 8.0 percent, stating that her initial recommendation was for a utility that is economically and efficiently managed, and that NEGC is not such a utility (Attorney General Brief at 51-52). Thus, she asserts that the allowed ROE should be at the low end of the range of reasonable returns to reflect certain of the Company's actions, which she maintains are imprudent and unreasonable (Attorney General Brief at 52, citing New England Gas Company, D.P.U. 08-110, at 14 (2010); D.T.E. 02-24/25, at 231; Attorney General Reply Brief at 20, 22).

First, the Attorney General asserts that the Company's choice of law firms to represent it in its environmental remediation matters demonstrates deficient management (Attorney General Brief at 52, 84-85). The Attorney General acknowledges that the Company recovers any environmental remediation costs, including associated legal costs, through the remediation adjustment factor ("RAF") component of its LDAC and, as such, that the costs are not at issue in this rate case proceeding (Attorney General Brief at 91).[187] Nonetheless, she asserts that the

[187] The Attorney General also asks that the Department initiate a full investigation of the Company's pass-through of environmental remediation costs via the RAF in the Company's next LDAC filing (Attorney General Brief at 91).

fact that one of Southern Union's highest-ranking executives remains a partner at a law firm that supports NEGC in the environmental remediation matters, and bills for legal services that are recovered through NEGC's RAF, creates a clear conflict of interest that is unreasonable (Attorney General Brief at 85, 90; Attorney General Reply Brief at 20, 22). The Attorney General contends that this conflict of interest is indicative of subpar corporate management, which should be reflected in a lower ROE (Attorney General Brief at 85-91; Attorney General Reply Brief at 20-23).

Second, the Attorney General contends that companies have been on notice that they must retain outside consultants through an open and transparent bidding process (Attorney General Brief at 83, citing D.P.U. 09-39, at 287; D.P.U. 08-35, at 129; D.P.U. 07-71, at 99-100; D.T.E. 03-40, at 153; D.T.E. 01-56, at 76; D.T.E. 98-51, at 59-60; D.P.U. 96-50 (Phase I) at 79). She asserts that NEGC's failure to solicit additional bids when there was only one respondent to the revenue requirements RFP demonstrates that it failed to conduct a competitive bidding process (Attorney General Brief at 83, citing D.P.U. 07-71, at 139-140). Thus, she asserts that the Department may take the failure to conduct an effective competitive bidding process into consideration in setting the allowed ROE in this case (Attorney General Brief at 52 n.15, citing D.P.U. 07-71, at 139-140).

Finally, the Attorney General notes that the Department determined in D.P.U. 08-110, at 14, that NEGC had made changes to a Department-ordered audit that materially altered the scope, intent, and results of such audit (Attorney General Brief at 52). Noting that the Department penalized Fitchburg Gas and Electric Light Company for a failure to provide complete information on a number of issues in a rate case proceeding, the Attorney General asserts that the Company's actions in both the handling of its environmental remediation legal fees and its actions in D.P.U. 08-110 demonstrate subpar management performance, and that the Department should reduce the Company's ROE accordingly (Attorney General at 52 & n.14, citing D.P.U. 08-110, at 14; D.T.E. 02-24/25, at 231).

b. Company

The Company states that in order for the Attorney General to make her 8.0 percent ROE recommendation she has to reject her own witness's recommended ROE of 9.0 percent, which NEGC notes is too low in any event to support safe and reliable utility operations (Company Brief at 63). The Company reports on the allowed ROEs of other natural gas distribution utilities stating that: (1) the Attorney General testified that natural gas utilities earned a return of 11.20 percent; (2) the trade journal Regulatory Focus reported the median 2010 ROE awarded to gas companies was 10.10 percent; and (3) Regulatory Focus reported the lowest ROE awarded to a gas company in 2010 was 9.19 percent and the next lowest was 9.40 percent (Company Brief at 63, citing Exh. AG-JRW-1, at 12). The Company further claims that an ROE of 8.0 or 9.0 percent would put the Company at a severe disadvantage as compared to other gas companies in terms of attracting capital (Company Brief at 64).

The Company contests the Attorney General's allegation of subpar management performance and her claim of deficiency in the Company's selection of its revenue requirement witness (Company Brief at 64). First, the Company argues that the choice of law firms to represent the Company in environmental remediation is justifiable on the basis of the complexity of the litigation involved, and that there were no ethical issues surrounding the choice of law firm because the Southern Union Board of Directors had adequate notice of any relationship between an officer of Southern Union and the law firm in question (Company Brief at 64). Second, NEGC argues that there is no basis for any claim that the Company failed to provide the Department with complete information in this case (Company Brief at 64). Third, the Company argues that the performance audit conducted in D.P.U. 08-110 has shown that the Company's management is not inadequate (Company Brief at 64). Finally, NEGC argues that the selection of the Company's revenue requirement witness is completely justified given the level of knowledge and experience she has with the Company's financial affairs (Company Brief at 64).

The Company states that the Court has made it clear that in calculating the ROE the guiding principle is that the ROE should be commensurate with returns on investments in other enterprises having similar risks (Company Brief at 65, citing Attorney Gen. v. Department of Public Utilities, 392 Mass. 262, 266 (1982)). NEGC further argues that departure from the Hope standard as articulated by the Massachusetts Supreme Judicial Court in numerous cases would lead to illegal confiscation (Company Brief at 65, citing 376 Mass. 294, 299). The Company concludes that any reduction to the allowed ROE for factors unrelated to the cost of capital would be legal error because the ROE authorized in this case must be sufficient to allow the Company to maintain its credit and ability to attract capital (Company Brief at 65, 70, citing Boston Edison Company v. Department of Public Utilities, 375 Mass. 1, 10 (1978); Hope).

3. Discounted Cash Flow Model

a. Company's Proposal

NEGC states that the DCF model is based on finding the present value of an expected future stream of net cash flows during the investment holding period discounted at the cost of capital or the capitalization rate (Exh. NEGC-FJH at 22). The Company also notes that the expected total return rate is derived from cash flows in the form of dividends received plus appreciation in market price, i.e., the expected growth rate (Exh. NEGC-FJH at 22).

The Company uses a form of the DCF model referred to as the Gordon DCF model, which, the Department notes, assumes an infinite investment horizon and a constant growth rate.[188] NEGC states that since regulation establishes a level of authorized earnings which, in turn, implicitly influence DPS, estimation of the growth rate from such data is an inherently circular process (Exh. NEGC-FJH at 20, citing Charles F. Phillips, Jr., The Regulation of Public Utilities – Theory and Practice, PUBLIC UTILITY REPORTS, INC., 1993, at 396, 398).

The Company states that the DCF model has a tendency to identify erroneously investors' required return rate when the market value of common stock differs significantly from its book value (Exh. NEGC-FJH at 24). Further, NEGC states that a market-based DCF cost rate will result in a total annual dollar return on book common equity equal to the total annual dollar return expected by investors only when market and book values are equal

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188 The Gordon DCF model is commonly expressed as: $k = D_1/P_0 + g$, where k is the investors' required return on common equity (or simply the cost of equity), D_1 is the DPS paid in the next period, P_0 is the current market price per share of the common stock, the term (D_1/P_0) is the expected dividend yield, and g is the investors' mean expected long-run growth rate in DPS (Exh. AG-JRW at 24-27).

(Exh. NEGC-FJH at 24). The Company refers to an Iowa Utilities Board decision in which that commission acknowledged that the DCF model may understate the ROE in some circumstances, particularly when the market is relatively volatile and the company in question has a market-to-book ratio in excess of one (Exh. NEGC-FJH at 29, citing Re: U.S. West Communications, Inc., Docket No. RPU-93-9, 152 PUR4th at 459 (1994)). Therefore, NEGC concludes that an adjustment to the results of its DCF analysis is necessary to ensure that the DCF results reflect investor expectations.

The Company utilized several steps in calculating its dividend yield. Initially, NEGC gives the spot dividend yield[189] on June 18, 2010, for each of the companies in its utility proxy group and the average two-month dividend yield for April and May, 2010 (Exhs. NEGC-FJH at 29; NEGC-FJH-1 Sch. 9). The Company then averages these figures for the utility proxy group with equal weight to produce a median dividend yield of 4.19 percent, which NEGC uses in its DCF model (Exh. NEGC-FJH-1, Sch. 9).

The Company states that because dividends are paid quarterly (or periodically) as opposed to continuously (or daily), an adjustment must be made (Exh. NEGC-FJH at 30). Specifically, the Company calculates one half of the average five-year projected growth rate and multiplies it by the average dividend yield to obtain an adjusted dividend yield (Exh. NEGC-FJH-1, Sch. 9, Sch. 11, at 1). NEGC explains that since companies tend to

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189 The Company explains that the spot dividend yield is the current annualized DPS divided by the spot market price of the shares on a specific date (Exh. NEGC-FJH-1, Sch. 9).

increase their quarterly dividend at different times of the year, this approach represents the dividend growth over the next twelve-month period (Exh. NEGC-FJH at 30).

NEGC states that individuals own 42 percent of the common shares of the companies in its proxy group (Exh. NEGC-FJH at 30). The Company's witness maintains that individual investors are much more likely to rely on information provided by securities analysts than are more sophisticated institutional investors (Exh. NEGC-FJH at 30-31). It is on this basis that NEGC utilizes the five-year forecasted growth estimates of Value Line, Reuters, and Zack's (Exhs. NEGC-FJH at 31; NECG-FJH-1, Sch. 11). Using the average of these three firms' five-year forecasts for the proxy group companies, NEGC determines a 4.94 percent DCF model growth rate (Exhs. NEGC-FJH at 31; NEGC-FJH-1, Sch. 11). With these figures, the Company derived a DCF model driven ROE of 9.32 percent (Exhs. NEGC-FJH at 32; NEGC-FJH-1, Sch. 1, at 2, Sch. 8).

b. Attorney General's Proposal

Prior to presenting her calculations of the DCF model, the Attorney General comments on the dividend discount model, which portrays the DCF model in three stages (Exh. AG-JRW-1, at 23). She states that the public utility industry is in the maturity, or steady-state, stage of the model, which is described as an industry in which new investment opportunities offer only slightly attractive returns on equity (Exh. AG-JRW-1, at 23). The Attorney General states that in the constant-growth version of the DCF model, the current dividend payment and stock price are directly observable, and therefore that the controversy is in estimating investors' expected dividend growth rate (Exh. AG-JRW-1, at 25).

In applying the DCF model, the Attorney General provides the dividend yields on the common stock of the nine companies in her Gas Proxy Group with a median six-month dividend yield of 4.20 percent (Exhs. AG-JRW-1, at 26; AG-JRW-10, at 2). The Attorney General averages this figure with the November 2010 median dividend yield for the Gas Proxy Group of 3.90 percent, resulting in her unadjusted DCF model dividend yield figure of 4.10 percent (Exhs. AG-JRW-1, at 26; AG-JRW-10, at 1-2). The Attorney General then adjusts this dividend yield by one-half the expected growth, or a factor of 1.0215,[190] to reflect the growth in the coming year (Exhs. AG-JRW-1, at 26-27; AG-JRW-10, at 1). The product of the 4.10 percent unadjusted dividend yield and the adjustment factor produces a 4.20 percent[191] adjusted dividend yield (Exh. AG-JRW-10, at 1).

In her analysis of the growth rate portion of the DCF model, the Attorney General included the average historic EPS, DPS, and book value per share ("BVPS") of 4.2 percent,[192] and the average projected EPS, DPS, and BVPS of 4.0 percent as provided by Value Line (Exhs. AG-JRW-1, at 32-33; AG-JRW-10, at 3). Also included were the average sustainable growth rate of 4.7 percent from Value Line[193] as well as the average of the projected EPS of

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190 This factor is calculated by multiplying the 4.30 percent growth rate by one-half and adding one to it, resulting in 1.0215 (Exh. AG-JRW-10, at 1).

191 This figure is rounded up from 4.18815 or 4.10 X 1.0215 (Exh. AG-JRW-10, at 1).

192 The Attorney General's growth rate summary sheet contains a typographical error that changed the historic growth from 4.2 percent to 4.4 percent (Exh. AG-JRW-10, at 6).

193 Sustainable growth or prospective internal growth for the Gas Proxy Group is measured by Value Line's average projected retention rate and return on shareholders' equity (Exh. AG-JRW-1, at 34).

4.2 percent from Yahoo! Finance ("Yahoo"), Zack's, and Reuters (Exhs. AG-JRW-1, at 33-35; AG-JRW-10, at 4-6). The average of all of these growth rate indicators for the Gas Proxy Group is 4.3 percent, which is the figure that the Attorney General used in her DCF model calculation (Exhs. AG-JRW-1, at 35; AG-JRW-10, at 6). Combining her adjusted dividend yield of 4.2 percent with her growth rate of 4.3 percent, the Attorney General calculated a DCF-model-derived ROE of 8.5 percent (Exhs. AG-JRW-1, at 35; AG-JRW-10, at 1).

c. Positions of the Parties

i. Attorney General

The Attorney General states that her major area of disagreement with the Company's DCF-model-derived ROE is the estimation of the expected growth rate (Attorney General Brief at 43).[194] The Attorney General claims that the long-term earnings growth rates of Wall Street analysts, used by NEGC, are overly optimistic and upwardly biased (Attorney General Brief at 43, citing Exh. AG-JRW-1, at 31-32, 53-62). She also claims that the estimated long-term EPS growth rates of Value Line, also used by NEGC, are overstated (Attorney General Brief at 43; see Exh. AG-JRW-1, at 56). She states that because of these biases, she used both historic and projected growth rate measures and evaluated growth in dividends, book value, and EPS (Attorney General Brief at 43).

194 Though the Attorney General addresses the CEM in tandem, we will review that approach below.

ii. Company

NEGC argues that individual investors rely on analysts' forecasts in making investment decisions because analysts' forecasts provide greater insight into prospective growth than historical measures, and that EPS forecasts are the principal driver of stock prices (Company Brief at 59, citing Exh. NEGC-FJH at 30-31). The Company maintains that the Attorney General recognized that one must use historical growth numbers as measures of investors' expectations with caution (Company Brief at 59, citing Exh. AG-JRW-1, at 29). The Company claims that this need for caution in assessing historic measures is the basis for the Attorney General's statement that, in general, more weight must be placed on forecasts than on other measures (Company Brief at 59, citing Tr. 6, at 708-709).

The Company asserts that the Attorney General's testimony shows that there is little upward bias in EPS growth rate projections by analysts when it comes to gas distribution companies, because the difference between actual and projected EPS growth rates for gas distribution companies was between 50 and 100 basis points over the last three-to-five-year period (Company Brief at 59, citing Exh. AG-JRW-1, at 66; Tr. 6, at 710-711). NEGC also argues that historical growth is included and reflected in analysts' forecasts (Company Brief at 59, citing Exh. NEGC-FJH at 30-31).

Lastly, the Company argues that the Department has repeatedly recognized the value of forecast data as a conceptually appropriate measure of growth (Company Brief at 59, citing D.T.E. 03-40, at 358; D.T.E. 05-27, at 298). The Company maintains that the Attorney

General's DCF model calculation is flawed, and that the Department should reject it (Company Brief at 59).

d. Analysis and Findings

Both the Company and the Attorney General used a form of the DCF model referred to as the Gordon DCF model, which assumes an infinite investment horizon and a constant growth rate (Exhs. NEGC-FJH at 22; AG-JRW-1, at 24). This model has a number of very strict assumptions (e.g., that dividends grow at a constant rate in perpetuity) (Exhs. NEGC-FJH at 22; AG-JRW-1, at 24). The model's assumptions give rise to specific limitations in the context of a rate case. Because regulation establishes a level of authorized earnings for a utility that, in turn, implicitly influences DPS, estimation of the growth rate from such data is an inherently circular process (Exh. NEGC-FJH at 20, citing Charles F. Phillips, Jr., The Regulation of Public Utilities – Theory and Practice, PUBLIC UTILITY REPORTS, INC., 1993, at 396, 398). Accordingly, we will consider these model limitations in evaluating the ROEs based on the DCF model that are presented in this proceeding.

4. Capital Asset Pricing Model

a. Company's Proposal

The Company states that the CAPM[195] defines risk as the covariability of a security's returns with the market's returns, and that this covariability is measured by beta (Exh. NEGC-FJH at 43). The Company explains that the CAPM assumes that all non-market,

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[195] The CAPM is expressed as: $R_s = R_f + \beta(R_m - R_f)$, where R_s is the return rate on the common stock, R_f is the risk-free rate of return, β is the volatility of the security relative to the market as a whole, R_m is the return rate on the market as a whole, and $(R_m - R_f)$ is the market risk premium (Exh. NEGC-FJH at 44).

or unsystematic, risk can be eliminated through diversification and that systematic risk, represented by beta, cannot be eliminated through diversification (Exh. NEGC-FJH at 43). The Company employs a 4.78 percent risk-free rate, and a 0.65 Value Line beta in calculating its CAPM-derived ROE (NEGC-FJH-1, Sch. 15, at 2-3). The Company obtained its risk-free rate from an average forecast based on six quarterly estimates of 30-year Treasury note yields as reported in the Blue Chip Financial Forecasts dated June 1, 2010 (Exh. NEGC-FJH-1, Sch. 15, at 3).

To develop its proposed market risk premium, NEGC first compared the three- to five-year forecast total annual market return of 13.74 percent for the Value Line Summary & Index with the risk-free cost rate derived above, producing a market premium of 8.96 percent (Exh. NEGC-FJH-1, Sch. 15, at 3). The Company then averaged the 8.96 percent market risk premium with the Morningstar (Ibbotson Associates) market premium of 6.60 percent, producing a overall market risk premium of 7.78 percent (Exhs. NEGC-FJH at 48-49; NEGC-FJH-1, Sch. 15, at 3). This overall market risk premium was then multiplied by the adjusted betas for each company in NEGC's utility proxy group to derive an average company-specfic risk premium of 5.06 percent (Exh. NEGC-FJH-1, Sch. 15, at 2). Application of the 4.78 percent risk-free rate, the 5.06 percent risk premium, and a company-specific beta of 0.65 to the traditional CAPM formula stated above produces an ROE of 9.84 percent (Exh. NEGC-FJH-1, Sch. 15, at 1).

The Company also presents an empirical CAPM ("ECAPM") calculation, which it derives from the formula $K=R_F+x(R_M-R_F)+(1-x)\beta(R_M-R_F)$ (Exh. NEGC-FJH at 45 n.17).

NEGC defines the new variable, x, as a fraction to be determined empirically, and the Company assigns it a 25 percent value (Exhs. NEGC-FJH at 45 n.17; NEGC-FJH-1, Sch. 15, at 3).[196] From this derivation, the Company proposes its ECAPM as $K=R_F+0.25(R_M\text{-}R_F)+0.75\beta(R_M\text{-}R_F)$ (Exh. NEGC-FJH at 45). The Company states that this calculation does not double count the Value Line beta adjustment,[197] but rather adjusts the scope of the Security Market Line ("SML")[198] to account for the observed flattening of the SML using actual returns (Exhs. NEGC-FJH at 45-46; NEGC-FJH-1, Sch. 15, at 3). The Company completes its ECAPM analysis using the same risk-free rate, beta, and market premium as its traditional CAPM on its utility proxy group, with a resulting 10.52 percent ECAPM-derived ROE (Exh. NEGC-FJH-1, Sch. 15, at 2). The Company averages its traditional CAPM of 9.84 percent with its ECAPM of 10.52 percent, resulting in a 10.18 percent CAPM-based ROE for inclusion in its final ROE recommendation (Exhs. NEGC-FJH-1, Sch. 1, at 2; NEGC-FJH-1, Sch. 15, at 1).

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196 The Company utilizes a study that found the relationship between the expected return and beta over the period 1926-1984 was given by $K=0.0829+0.0520\beta$ (Exh. NEGC-FJH at 45 n.17, citing Roger A. Morin, New Regulatory Finance, PUBLIC UTILITIES REPORTS, INC., 2006, at 279-281). The Company explains that the intercept of the observed relationship between return and beta exceeds the risk-free rate by about two percent, or 1/4 of eight percent, and that the slope of the relationship (six percent) is close to 3/4 of eight percent (Exh. NEGC-FJH at 45 n.17).

197 Value Line adjusts its calculated betas, via regression analysis, for the tendency of betas to approach one (Exh. NEGC-FJH at 45).

198 The SML graphs market risk versus market return at a given point in time. The SML assists the investor in determining whether an asset is overvalued or undervalued relative to the market.

b. Attorney General's Proposal

The Attorney General concurs with the Company that in the CAPM there are two types of risk (i.e., firm-specific risk (unsystematic) and market risk (systematic)), and that investors receive a return only for bearing systematic risk (Exhs. AG-JRW-1, at 36; NEGC-FJH at 43). She further explains the three components of the traditional CAPM stating: (1) R_f is the yield on long-term Treasury bonds, (2) β is the measure of systematic risk,[199] and (3) $(E(R_{m)}-(R_f))$[200] is the difference in the expected total return between investing in equities and investing in "safe" fixed-income assets and is even more difficult to capture (Exh. AG-JRW-1, at 36-37, 39).

The Attorney General utilizes the 30-year Treasury bond rate in her CAPM (Exh. AG-JRW-1, at 38). She maintains that the yield on 30-year Treasury bonds has been in the 4.0 percent to 4.25 percent range over the months preceding the date of her testimony, and that as of November 18, 2010, it was 4.31 percent (Exhs. AG-JRW-1, at 38; AG-JRW-11, at 2). The Attorney General used a 4.25 percent risk-free rate of return in her CAPM (Exh. AG-JRW-1, at 38). The Attorney General also employs the Value Line betas for the

[199] The Attorney General states that the beta is more difficult to measure because there are different opinions about what adjustments, if any, should be made to historical betas due to their tendency to regress to 1.0 over time (Exh. AG-JRW-1, at 37).

[200] The Attorney General explains that this notation recognizes that the figure is the expected '*E*' return on the market minus the risk-free rate of return (Exh. AG-JRW-1, at 37). The Department notes that this is merely a more elegant form of the corresponding market risk premium notation R_m-R_f referenced above.

Gas Proxy Group, calculating a median figure of 0.65 for use in her CAPM (Exhs. AG-JRW-1, at 39; AG-JRW-11, at 3).

The Attorney General states that the Company's market risk premium estimates are out of line with the market risk premium estimates: (1) discovered in recent academic studies by leading finance scholars; and (2) employed by leading investment banks, management consulting firms, financial forecasters, and corporate chief financial officers (Exh. AG-JRW-1, at 83). Further, she claims that a more realistic market risk premium is in the range of 4.0 to 5.0 percent above Treasury yields (Exh. AG-JRW-1, at 83). The Attorney General compiled a list of studies of the equity risk premium from which she extracted a subset of studies published after January 2, 2010 (Exhs. AG-JRW-1, at 42-43; AG-JRW-11, at 5-6). She then categorized this subset into historical risk premium, "ex ante" models, surveys, and building block methodology (Exhs. AG-JRW-1, at 42; AG-JRW-11, at 6). The Attorney General used the median equity risk premium of 4.68 percent derived from the 2010 studies and surveys in her CAPM calculation (Exhs. AG-JRW-1, at 44; AG-JRW-11, at 6). The Attorney General calculates her CAPM in the same way the Company calculates its traditional CAPM, resulting in a 7.30 percent CAPM-derived ROE (Exhs. AG-JRW-1, at 46; AG-JRW-11, at 1).

c. Positions of the Parties

i. Attorney General

The Attorney General argues that there are three errors in NEGC's CAPM analysis: (1) its risk-free rate of interest; (2) the use of the so-called ECAPM; and (3) the equity or market risk premiums for both its CAPM and ECAPM (Attorney General Brief at 45, citing Exh. AG-JRW-1, at 78-83). The Attorney General explains that because the current risk-free interest rate on long-term U.S. Treasury bonds is 4.31 percent, NEGC's CAPM results are overstated by 40-50 basis points (Attorney General Brief at 45, citing Exh. AG-JRW-1, at 79).

The Attorney General contends that the primary issue with the Company's CAPM analysis is the magnitude of the equity risk premium (Attorney General Brief at 45). The Attorney General lists the Company's errors, including: (1) biased historical bond returns; (2) the use of the arithmetic mean versus the geometric mean return; (3) measurement of the equity risk premium using historical returns; (4) unattainable and biased historical stock returns; (5) company survivorship bias; and (6) a U.S. stock market survivorship bias (Attorney General Brief at 48, citing AG-JRW-1, at 70-78).

ii. Company

The Company argues that the Attorney General's reliance on studies rather than on the historically based Morningstar in establishing an equity risk premium is misplaced, because investors are much more likely to rely on and review Morningstar than academic studies (Company Brief at 60, citing Exh. NEGC-FJH at 38-39). NEGC further argues that the Attorney General's CAPM analysis inappropriately ignores the most influential investor publication available, Value Line, and its projected returns on the market (Company Brief at 60, citing Exh. AG-JRW-1, at 39-46). The Company also argues that the Attorney General's CAPM inappropriately relies on the geometric mean rather than the arithmetic mean (Company Brief at 60, citing Exhs. NEGC-FJH at 38-39; AG-JRW-1, at 39-46). The

Company states that the arithmetic mean should be used because it provides insight into the potential variance of expected returns, which the Company asserts is why the arithmetic mean is used by Morningstar (Company Brief at 60-61, citing Exh. NEGC-FJH at 39).

d. Analysis and Findings

The Department has previously found that the traditional CAPM as a basis for determining a utility's cost of equity has limited value, and in some cases no value, because of a number of limitations, including questionable assumptions that underlie the model. D.P.U. 10-70, at 267; D.P.U. 08-35, at 207; D.T.E. 03-40, at 359-360; D.P.U. 956, at 54.[201] The Company calculated an ECAPM in addition to its traditional CAPM results. The ECAPM includes variables representing risk-adjusted beta diluted by performance measures with respect to which NEGC maintains it is performing above and beyond traditional benchmarks (Exhs. NEGC-FJH at 45 n.17; NEGC-FJH-1, Sch. 15, at 3). We are not persuaded that NEGC's expected return would be representative of a company performing financially above and beyond that of the market as a whole. Moreover, the Company's return projections are

[201] The Department identified the following questionable assumptions used in the CAPM: (1) capital markets are perfect, with no transaction costs, taxes, or impediments to trading; all assets are perfectly marketable; and no one trader is significant enough to influence price; (2) there are no restrictions to short-selling securities; (3) investors can lend or borrow funds at the risk-free rate; (4) investors have homogeneous expectations (i.e., investors possess similar beliefs on the expected returns and risks of securities); (5) investors construct portfolios on the basis of the expected return and variance of return only, implying that security returns are normally distributed; and (6) investors maximize the expected utility of the terminal value of their investment at the end of one period. D.P.U. 08-35, at 207 n.131.

consistently high relative to actual experienced returns, as demonstrated by Value Line's three-to-five-year annual returns over the previous 25 years (Exh. AG-JRW-15, at 1).

Based on the above considerations, the Department concludes that the traditional CAPM and the ECAPM tend to overstate the required return on common equity for NEGC. Accordingly, the Department finds that the traditional CAPM and ECAPM have limited value in determining the Company's appropriate rate of return on common equity in this case.

5. Risk Premium Model

a. Company's Proposal

NEGC developed an ROE from the RPM, which the Company states is based upon the theory that the cost of common equity capital is greater than the prospective company-specific cost rate for long-term debt capital (Exh. NEGC-FJH at 32). The Company explains further that the RPM is the expected cost rate for long-term debt capital plus a premium to compensate common shareholders for the added risk of being unsecured and last in line in any claim on the corporation's assets and earnings (Exh. NEGC-FJH at 32).

Initially, the Company estimates a prospective bond yield on A-rated public utility bonds to be 5.96 percent (Exhs. NEGC-FJH at 33; NEGC-FJH-1, Sch. 12, at 1, 6). This figure is comprised of an average forecast based on six quarterly estimates of Moody's Aaa-rated corporate bonds[202] of 5.43 percent and an adjustment of 53 basis points to represent the yield spread between Moody's Aaa-rated corporate bonds and Standard & Poor's A-rated

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[202] These estimates come from Blue Chip Financial Forecasts dated June 1, 2010 (Exh. NEGC-FJH-1, Sch. 12, at 6).

public utility bonds (Exh. NEGC-FJH-1, Sch. 12, at 1, 3, 6). NEGC reasons that since its proxy group has an average Moody's bond rating of A3, an upward adjustment of 14 basis points is necessary (Exhs. NEGC-FJH at 33; NEGC-FJH-1, Sch. 12, at 1-2).[203] This results in an adjusted prospective bond yield of 6.10 percent, which is the final figure used by NEGC (Exhs. NEGC-FJH at 33-34; NEGC-FJH-1, Sch. 12, at 1).

The Company then averages three equity risk premium estimates to arrive at its final 4.31 percent equity risk premium (Exhs. NEGC-FJH at 42; NEGC-FJH-1, Sch. 12, at 5). The first of these estimates, 4.56 percent, is based on the Company's calculation of the average of the historical and the projected market equity risk premiums of 5.70 percent and 8.31 percent respectively, or 7.01 percent allotted to the utility proxy group by multiplying by its median beta of 0.65, all of which the Company terms "the beta approach" (Exhs. NEGC-FJH at 35, 38; NEGC-FJH-1, Sch. 12, at 5-6). Second, NEGC estimates an equity risk premium of 3.98 percent, based on the mean holding period returns of the Standard & Poor's Utility Index for the period 1928 through 2008 over the mean yield on Moody's A3 rated public utility bond over the same period (Exhs. NEGC-FJH at 35; NEGC-FJH-1, Sch. 12, at 8). And lastly, the Company averaged in a 4.40 percent equity risk premium resulting from a regression analysis based on 281 fully litigated gas distribution rate cases (Exhs. NEGC-FJH at 36; NEGC-FJH-1, Sch. 12, at 5, Sch. 13). From these figures, the Company proposes an RPM-derived ROE of 10.41 percent, the sum of the adjusted prospective bond yield of

[203] NEGC calculates the 14 basis point adjustment by taking 1/3 of the spread between Baa2 and A2 Public Utility Bonds (Exh. NEGC-FJH-1, Sch. 12, at 1).

6.10 percent and the estimated equity risk premium of 4.31 percent (Exh. NEGC-FJH at 42, Sch. 12, at 1).

b. Positions of the Parties

i. Attorney General

The Attorney General claims that both the Company's prospective bond yield and its risk premium are excessive (Attorney General Brief at 47, citing Exh. AG-JRW-1, at 68-77). The Attorney General assserts that NEGC's prospective bond yield of 6.10 percent is overstated for two reasons: (1) the forecasted Aaa corporate bond rate of 5.43 percent is above the current Aaa corporate bond rate; and (2) employing the yield on long-term risky bonds overstates the required ROE in two ways: (a) long-term bonds are subject to interest rate risk, a risk which does not affect common stockholders since dividend payments (unlike bond interest payments) are not fixed but tend to increase over time; and (b) the base yield is subject to credit risk since it is not default-risk free like an obligation of the U.S. Treasury (Attorney General Brief at 47, citing Exh. AG-JRW-1, at 68-69). The Attorney General concludes that as a result, the yield-to-maturity includes a premium for default risk and therefore is above the expected return (Attorney General Brief at 47, citing Exh. AG-JRW-1, at 68-69). The Attorney General contends that, in addition to the errors explained in the CAPM section above, there are a number of empirical issues in using historical stock and bond returns to estimate a risk premium (Attorney General Brief at 48).[204]

[204] The Attorney General's argument regarding the Company's risk premium estimates are found in the discussion of NEGC's CAPM analysis (see Section VI.E.4., above).

ii. Company

The Company argues that the Department should at least supplement its calculation of the Company's ROE with the RPM (Company Brief at 60). NEGC maintains that the Department has viewed the RPM as a supplemental approach in determining a company's ROE in the past (Company Brief at 60, citing D.P.U. 07-71, at 137).

c. Analysis and Findings

The Department has repeatedly found that a risk premium analysis could overstate the amount of company-specific risk and, therefore, overstate the cost of equity. See D.P.U. 90-121, at 171; Commonwealth Electric Company, D.P.U. 88-135/151, at 123-125 (1989); D.P.U. 88-67 (Phase I) at 182-184. More specifically, the Department has found that the return on long-term corporate or public utility bonds may have risks that could be diversified with the addition of common stock in investors' portfolios and, therefore, that the risk premium model overstates the risk accounted for in the resulting cost of equity. D.P.U. 90-121, at 171; D.P.U. 88-67 (Phase I) at 182-183.

The risk premium model, like the other equity cost models used by NEGC, suffers from a number of limitations, including potential imprecision in the assessment of future cost of corporate debt and the measurement of the risk-adjusted common equity premium. The Department has acknowledged the value of the RPM as a supplemental approach to other ROE models and accords it, at best, limited weight in our determination of the cost of equity. D.P.U. 07-71, at 137; D.T.E. 99-118, at 85-86. In addition, the RPM suffers from the same limitations previously noted in the CAPM.

For these reasons, the Department finds that NEGC's RPM tends to overstate the required ROE for the Company. Accordingly, we will place limited weight on the results of the Company's RPM.

6. Comparable Earnings Method

a. Company's Proposal

The Company proposes an ROE based upon its calculations of market-based common equity cost rates for a proxy group of domestic, non-price regulated companies that are similar in total risk to the Company's utility proxy group (Exh. NEGC-FJH at 54). NEGC compiles its non-price regulated proxy group of 14 companies relying on the market prices paid by investors and a series of screens (Exhs. NEGC-FJH at 51-52; NEGC-FJH-1, Sch. 16, at 2).[205] The Company states that it applied the DCF model, CAPM, and RPM in the same manner as it did for its utility proxy group (Exh. NEGC-FJH at 54).

The Company's DCF-model-derived ROE consists of an adjusted dividend yield and an average growth rate for each of the 14 companies with a resultant median of 12.45 percent (Exhs. NEGC-FJH at 55; NEGC-FJH-1, Sch. 17, at 2). NEGC calculates a CAPM-derived ROE from the application of a 0.65 beta, market risk premium of 7.78 percent, and risk-free rate of 4.78 percent, which results in a CAPM of 9.84 percent and an ECAPM of

[205] The non-price regulated proxy group screens are that: (1) they must be covered by Value Line; (2) they must be domestic, non-price regulated companies, i.e., non-utilities; (3) their betas must lie within plus or minus two standard deviations of the average unadjusted beta of the utility proxy group; (4) the residual standard errors of the regressions must lie within plus or minus two standard deviations of the average residual standard error of the regression for the utility proxy group (Exh. NEGC-FJH at 52).

10.52 percent or an average CAPM of 10.18 percent (Exhs. NEGC-FJH at 56; NEGC-FJH-1, Sch. 17, at 7). The Company's non-price regulated RPM-derived ROE of 10.50 percent consists of an adjusted prospective bond yield of 5.94 percent and an equity risk premium of 4.56 percent (Exhs. NEGC-FJH at 55-56; NEGC-FJH-1, Sch. 17, at 3). The Company averages the results of the three models to conclude its CEM analysis, resulting in a CEM-derived ROE of 11.04 percent (Exhs. NEGC-FJH at 56; NEGC-FJH-1, Sch. 17, at 1).

b. Positions of the Parties

i. Attorney General

In addition to the flaws identified with respect to each of the other models, the Attorney General adds that whereas companies in the non-price regulated proxy group do have betas that are similar to those of the Company's utility proxy group, financial statistics for the CEM-based companies provided are not comparable to the utility proxy group companies (Attorney General Brief at 42, citing Exh. AG-JRW-1, at 86-88). The Attorney General claims that the companies in the CEM-based group: (1) are about ten times the size of the gas group; (2) are much less capital intensive; (3) have a higher valuation level; (4) have a projected ROE of more than double the ROE of the gas group; (5) have a market-to-book ratio of more than two times the gas group; and (6) have a projected long-term EPS growth rate that is more than double the gas distribution company proxy group (Attorney General Brief at 42, citing Exhs. AG-JRW-1, at 87; AG-JRW-16).

ii. Company

The Company did not comment on its CEM analysis on brief.

c. Analysis and Findings

The Department has generally rejected the results of the CEM analysis because the risk criteria provided were not sufficient to establish the comparability of the non-price-regulated group of firms with the distribution company being considered. D.P.U. 08-35, at 210; D.T.E. 01-56, at 116. Although the average adjusted betas of the CEM proxy group of 14 non-price regulated companies are comparable to the average adjusted betas of the nine utility proxy group companies, there are other risk criteria that must be evaluated as the basis for selecting an appropriate non-price regulated proxy group. See D.P.U. 08-35, at 210; D.T.E. 01-56, at 116.[206] We find the Attorney General's list of other financial criteria to be informative, including: (1) the size of the firm; (2) capital intensity; (3) valuation level; (4) projected ROE; (5) market-to-book ratio; and (6) projected long-term EPS growth rate (Exhs. AG-JRW at 87; AG-JRW-16).

In addition, the Department has found that the use of the beta as a criterion in selecting a comparable group of companies is not a reliable investment risk indicator given its statistical measurement limitations. D.P.U. 96-50 (Phase I) at 132. Moreover, the beta, which is a measure of risk based on the CAPM, reflects the limitations of that model, including its unrealistic assumptions as noted above. The results of the CEM analysis here, which the Company decided not to use in its determination of the recommended cost of equity, reflect these concerns. Accordingly, the Department will not rely on the results of the CEM analysis as a basis for determining the rate of return on common equity for NEGC.

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206 Another risk criterion would be the nature of the business. D.T.E. 01-56, at 116.

7. ROE Adjustment For Company's Size

a. Company's Proposal

The Company states that companies in its proxy group of nine gas distribution companies are on average 18.2 times larger than NEGC based on market capitalization (Exh. NEGC-FJH at 58). NEGC also theorizes that because NEGC has no common stock that is traded, it would have sold at the median market-to-book ratio of 165.1 percent of the utility proxy group on June 18, 2010 (Exhs. NEGC-FJH at 58; NEGC-FJH-1, Sch. 18, at 2). NEGC states that the results of its analysis indicate that an upward adjustment of 457 basis points should be made to the ROE derived from the utility proxy group (Exh. NEGC-FJH at 60-61). The Company explains that small firms are expected to earn higher returns because of their size and, therefore, may end up struggling to meet the demands of the capital market (Exh. NEGC-FJH at 60). For these reasons, the Company proposes what it considers to be an extraordinarily conservative 46 basis point increase to its unadjusted 10.24 percent ROE recommendation (Exhs. NEGC-FJH at 60-61; NEGC-FJH-1, Sch. 1, at 2).

b. Attorney General's Proposal

The Attorney General opposes any size-based ROE adjustment. She states that one-half of the historic return premium for small companies disappears once biases are eliminated and historic returns are properly computed (Exh. AG-JRW-1, at 84-85, citing Richard Roll, On Computing Mean Returns and the Small Firm Premium, JOURNAL OF FINANCIAL ECONOMICS, 1983, at 371-386). The Attorney General maintains that this disappearance of the historic return premium arises from the assumption of monthly portfolio rebalancing and the serial correlation in historic small firm returns (Exh. AG-JRW-1, at 85). The Attorney General explains that many studies have demonstrated that smaller companies have historically earned higher stock market returns. (Exh. AG-JRW-1, at 85, citing Ching-Chih Lu, The Size Premium in the Long Run, 2009 Working Paper SSRN abstract no. 1368705). The Attorney General states that these studies, however, rely on data sorting techniques that bias the results (Exh. AG-JRW-1, at 85, citing Ching-Chih Lu, The Size Premium in the Long Run, 2009 Working Paper SSRN abstract no. 1368705). She further explains that the effect is that the size premium disappears within two years (Exh. AG-JRW-1, at 85, citing Ching-Chih Lu, The Size Premium in the Long Run, 2009 Working Paper SSRN abstract no. 1368705).

c. Positions of the Parties

The Company argues that smaller companies are less capable of coping with significant events that affect sales, revenues, and earnings, such as the loss of revenues from a few larger companies (Company Brief at 52, citing Exh. NEGC-FJH at 57). Further, NEGC states that the ROE must reflect the impact of the Company's smaller size on ROE because it is significantly smaller than the average company in the utility proxy group, which was on average 18.2 times larger, based on market capitalization (Company Brief at 52-53, citing Exh. NEGC-FJH at 57-58). No other party commented on this matter on brief.

d. Analysis and Findings

NEGC made an upward adjustment of 46 basis points to its initial 10.24 percent ROE recommendation based on the Company's small size (Exhs. NEGC-FJH at 60-61; NEGC-FJH-1, Sch. 1, at 2). The Company based its adjustment on Morningstar data, which

NEGC also used in its previous rate case (Exh. NEGC-FJH-1, Sch. 18). In that case we stated:

> The Department has a number of concerns on the Company's proposed upward adjustment on the rate of return on common equity. The Morningstar study includes companies that are non-price regulated such that their risk profiles may not be comparable with the risk profiles of the companies in the comparison group and of NEGC. More specifically, the companies included in the Morningstar study have betas greater than one, unlike the betas of the companies in the comparison group that are less than or at most equal to one. Therefore, using company size only to place the companies of the comparison group within the sixth decile and NEGC within the tenth decile may not provide a sufficient basis for comparability.
>
> In addition, the estimates of the size premia for each of the ten deciles of companies in the Morningstar study were based on the traditional CAPM. As we noted above, there are many limitations of the traditional CAPM including the underlying model assumptions. The calculations of rates of return on common equity, including the calculations of the size premia in the Morningstar study, would reflect those limitations. Based on these considerations, the Department concludes that the Company's proposed upward adjustment of 0.40 percent tends to overstate NEGC's cost rate of common equity.

D.P.U. 08-35, at 216-217.

NEGC has not presented any new evidence that would serve as a basis for the Department to re-evaluate our previous findings here. Accordingly, the Department rejects NEGC's proposed size adjustment to ROE.

F. Impact of Decoupling on Cost of Equity

1. Company's Proposal

The Company recommends a two basis point decrease to its initial ROE recommendation on the basis of its judgment that the maximum value of a decoupling mechanism is 25 basis points and that the average company in the utility proxy group already collects 90.27 percent of their aggregate revenues from decoupled operations

(Exhs. NEGC-FJH at 62-63; NEGC-FJH-1, Sch. 1, at 2).[207] After these calculations, the Company proposes a 10.67 percent ROE, which it rounds to 10.65 percent (Exhs. NEGC-FJH at 66; NEGC-FJH-1, Sch. 1, at 2). In the event the Company's RDM proposed in this proceeding is not approved, however, the Company proposes an alternative 10.90 percent ROE (Exh. NEGC-FJH at 66).

2. Attorney General's Proposal

The Attorney General explains that the extent of decoupling as measured by the percentage of decoupled gas revenues (as opposed to customers) is the appropriate measure for evaluating the effects of decoupling on risk (Exh. AG-JRW-1, at 51). The Attorney General also states that removing those companies with weather normalization adjustment ("WNA") mechanisms and straight-fixed variable ("SFV") mechanisms results in a decrease of customers subject to an RDM (i.e., from 90.27 percent to 53.79 percent) (Exh. AG-JRW-1, at 51). In addition, the Attorney General points out that a significant portion of the revenues of the companies analyzed is not related to gas distribution and, therefore, is not subject to an RDM, SFV, or WNA (Exh. AG-JRW-1, at 52).

While the Attorney General makes no specific recommendation on an ROE adjustment based on the RDM proposed in this proceeding, she does recommend that the Department take into consideration the risk reduction associated with the Company's rate design proposal and make an adjustment based on: (1) whether the Company's proposed rate design is adopted;

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207 The Company calculates this as 0.25 percent multiplied by 9.75 percent, which is 2.43 percent or two basis points (Exh. NEGC-FJH at 63).

(2) the potential risk reduction associated with the adoption of the rate design; and (3) the adjustments made by other commissions for RDMs (Exh. AG-JRW-1, at 53).

3. Positions of the Parties

a. Attorney General

The Attorney General states that to justify the need for an adjustment to ROE if the RDM is not approved, NEGC claims to have computed the percent of revenues that are decoupled for each company (Attorney General Brief at 49, citing Exh. NEGC-FJH-1, Sch. 4, at 1). The Attorney General claims that the Company actually computes the percent of customers that are decoupled for the utility proxy group (Attorney General Brief at 50, citing Exhs. AG-JRW-1, at 51; AG-8-2). She also claims that the Company indicated that the data were not available when it was asked to provide the percent of decoupled gas revenues (and not customers) for the utility proxy group companies (Attorney General Brief at 50, citing Exhs. AG-JRW-1, at 51; AG-8-2). Among her reasons why decoupled customers are not necessarily a good proxy for decoupled revenues, the Attorney General argues that revenues attributable to large industrial customers, whose bills are based on gas volumes consumed, are not decoupled (Attorney General Brief at 50, citing Exh. AG-JRW-1, at 51-52).

In addition, the Attorney General explains that there is no support for the Company's claim that any decreased risk associated with decoupling is already reflected in the stock prices of the proxy group companies, since its proxy group companies received a significant portion of revenues from unregulated operations (Attorney General Brief at 50, citing Exh. AG-JRW-1, at 52).

b. Company

The Company argues that under the comparability standard established by the Hope decision, if the Company's decoupling mechanism is implemented, NEGC will be more comparable to the utility proxy group (Company Brief at 61). NEGC argues that a WNA mechanism is a partial, albeit substantial, decoupling mechanism since the largest variant in gas revenues is weather, and therefore, companies with weather normalization mechanisms are comparable to those subject to a full RDM (Company Brief at 62, citing Exh. NEGC-FJH at 13). Further, the Company asserts that NEGC's calculation that 90.27 percent of the customers of the gas companies in the proxy group are covered by decoupling-type mechanisms is accurate (Company Brief at 62, citing Exhs. NEGC-FJH at 13-14; NEGC-FJH-1, Sch. 4). In response to the Attorney General's arguments, the Company maintains that, even by the Attorney General's calculations, over two-thirds of the revenues of the gas companies in the proxy group are regulated (Company Brief at 62, citing Attorney General Brief at 51). And, the Company argues, this is substantial enough for comparability purposes in light of the Department's recognition that it is impossible to find a proxy group that matches the Company in every detail (Company Brief at 62, citing D.T.E. 05-27, at 296-297; D.P.U. 08-35, at 176).

4. Analysis and Findings

In D.P.U. 07-50-A, the Department stated that, because decoupling is designed to ensure that distribution companies' revenues are not adversely affected by reductions in sales arising from energy efficiency, demand-response, and distributed resources initiatives, by definition decoupling reduces earnings volatility. D.P.U. 07-50-A at 72; D.P.U. 07-50, at 1-2. The Department added that such reduction in earnings volatility should reduce risks to shareholders and, thereby, should serve to reduce the required ROE. D.P.U. 07-50-A at 72-73.

The Department stated, however, that it will consider the impact of a decoupling mechanism on a distribution company, along with all other factors affecting that company's required ROE, in the context of a rate proceeding, where the evidence and arguments may be fully tested. D.P.U. 07-50-A at 74. We consider below the impact of the Company's RDM on its allowed ROE.

The Department has previously rejected proposals for adjusting rate year revenues between rate filings due to variations in weather. See, e.g., D.T.E. 03-40, at 407, 423; D.P.U. 92-210, at 157-172, 199; D.P.U. 92-111, at 18-33, 60-61. In rejecting those proposals, the Department found that a weather adjustment would result in a less risky profile for the Company, and that any resulting reduction in risk of equity investments should be shared with ratepayers through a commensurate adjustment in a company's rate of return on capital. D.T.E. 03-40, at 423; D.P.U. 92-210, at 199; D.P.U. 92-111, at 60-61. In the instant case, in which changes in sales arising from all factors, including weather, are decoupled from the Company's approved base distribution rates, we reaffirm the above findings regarding the resulting lowered risk profile of a company and the resulting impact on its cost of equity. See D.P.U. 09-30, at 369. In addition, based on the specific record in this case, we confirm the Department's generic finding in D.P.U. 07-50-A at 72-73 that, because decoupling is designed to ensure that distribution companies' revenues are not adversely affected by reductions in sales arising from energy efficiency, demand-response, and distributed resources initiatives, such a reduction in revenues and earnings volatility should reduce risks to shareholders and, thereby, serve to reduce the required ROE. In sum, we find that the RDM that we have approved in this case will reduce the variability of the Company's revenues and, accordingly, reduce its risks and its investors' return requirement. See D.P.U. 09-30, at 367, 371-372; D.P.U. 07-50-A at 72-73.

The Company states that the absolute maximum value of a decoupling mechanism in relation to ROE is 25 basis points (Exh. NEGC-FJH at 61). This assumption comes from NEGC's analysis of nine gas distribution rate cases in other jurisdictions, in which the companies' ROEs were adjusted (Exh. NEGC-FJH at 62). The Company makes a reduction of two basis points to its recommended ROE. We do not accept the Company's calculation of the equity cost impact of decoupling. We are not convinced that the Company's purely quantitative method correctly captures the risk-reducing impact of the Company's decoupling mechanism. We will, instead, examine the specific risk profile of the Company and the specific features of the revenue decoupling proposal we are approving today to arrive at the appropriate determination of the effect on risk on NEGC's required ROE.

G. Conclusion

The standard for determining the allowed ROE is set forth in Bluefield at 679, 692-693, and Hope at 591. The allowed ROE should preserve the Company's financial integrity, allow it to attract capital on reasonable terms, and be comparable to returns on investments of similar risk. See Bluefield at 692-693; Hope at 603, 605.

In support of its calculations of an appropriate ROE, NEGC has presented analyses using the DCF model, CAPM (and ECAPM variation), and RPM, incorporating the financial data of its utility proxy group of nine gas distribution companies. The Attorney General has presented her own analyses using the DCF model and CAPM, incorporating the financial data of her Gas Proxy Group of nine gas distribution companies. The use of these empirical analyses in this context, however, is not an exact science. A number of judgments are required in conducting a model-based rate of return analysis. Even in studies that purport to be mathematically sound and highly objective, crucial subjective judgments are made along the way and necessarily influence the end result. Western Massachusetts Electric Company, D.P.U. 18731, at 59 (1977). Each level of judgment to be made in these models contains the possibility of inherent bias and other limitations. D.T.E. 01-56, at 117; D.P.U. 18731, at 59.

As stated above, the record demonstrates that all these equity cost models suffer from a number of simplifying and restrictive assumptions. Applying them to the financial data of a proxy group of companies could provide results that may, or may not, be reliable for the purpose of setting the Company's ROE. We note, for example, the limitations of the DCF model, used by both NEGC and the Attorney General, including the traditional assumptions that underlie the Gordon form of the model. Moreover, we also note, the CAPM relied upon by NEGC and the Attorney General is limited, both by the simplifying assumptions underlying CAPM theory, as well as by the subjectivity inevitable in estimating market risk premiums.

As noted above, we recognize that the RDM we have approved in this case will reduce the variability of the Company's revenues and, accordingly, reduce its risks and its investors' return requirement. See D.P.U. 09-30, at 371-372; D.P.U. 07-50-A at 72-73. Although the companies in the proxy groups used by NEGC and the Attorney General have some forms of revenue stabilization or decoupling mechanisms, the degree of revenue stabilization varies among the companies in the proxy groups and, on the whole, is not as comprehensive as the decoupling mechanism approved for the Company in this Order.[208]

Further, we note that a portion of the revenues of the gas companies in NEGC's utility proxy group and the Attorney General's Gas Proxy Group is derived from unregulated and competitive lines of business.[209] This mix of regulated and unregulated operations could skew the risk profile of the regulated gas distribution operations of the Company as compared to the companies in the proxy groups in a manner that, all else being equal, would tend to overstate the proxy groups' risk profiles relative to that of the Company. We will consider such risk differentials in determining the Company's allowed ROE.

While the results of analytical models are useful, the Department must ultimately apply its own judgment to the evidence to determine an appropriate rate of return. We must apply to

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208 For example, the decoupling mechanisms of the companies in the proxy group affect between 46 to 100 percent of their customers, and jurisdictions have approved various decoupling mechanisms, including full decoupling, weather normalization, straight fixed-variable pricing, and conservation incentive programs (Exh. NEGC-FJH-1, Sch. 4, at 1-10).

209 For example, AGL Resources and WGL Resources are engaged in gas marketing, and Piedmont Natural Gas is engaged in the sale of gas-fired heating equipment, natural gas brokering, and propane (Exh. NEGC-FJH-1, Sch. 11, at 1-10).

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.T.E. 07-71, at 139; D.T.E. 01-56, at 118; D.P.U. 18731, at 59; see also 375 Mass. 1, 15.[210] The Department must account for additional factors specific to a company that may not be reflected in the results of the models.

The Attorney General asserts that the Department should take into consideration the performance of the Company's management in establishing the allowed ROE (Attorney General Brief at 52). NEGC contends that any reduction to the ROE for factors unrelated to the cost of capital would be legal error (Company Brief at 70, citing 375 Mass. 1, 10). The Department has previously found that where there is a range of appropriate returns, both qualitative and quantitative factors must be taken into account. See, e.g., 375 Mass. 1, 11; Boston Gas Company v. Department of Public Utilities, 359 Mass. 292, at 305-306 (1971); 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 One) at 224-225. Specifically with respect to a

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210 We reaffirm the Department's prior comment on setting a company's ROE:

> 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.

New England Telephone and Telegraph Company, D.P.U. 17441, at 9 (1973).

company's management, we have determined that where a company's actions have the potential to affect ratepayers, the Department may take such actions into consideration in setting the ROE. D.T.E. 02-24/25, at 231; D.P.U. 85-266-A/271-A at 6-14; New England Telephone and Telegraph Company, D.P.U. 17441, at 9 (1973). Thus, the Department has set ROEs that are at the higher or lower end of the reasonable range based on above average or subpar management performance. See, e.g., D.P.U. 08-35, at 220; D.P.U. 08-27, at 134-138; D.T.E. 02-24/25, at 231 (2002); D.P.U. 92-78, at 115; D.P.U. 89-114/90-331/91-80 (Phase One) at 224-225; D.P.U. 85-266-A/271-A at 172-173. We find no reason to depart from our long-standing precedent and the accepted regulatory practice[211] of considering qualitative factors such as management performance and customer service in setting a fair and reasonable ROE. Therefore, we find it appropriate in this proceeding to consider both qualitative and quantitative factors in setting the ROE.

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211 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 Communications, Inc. v. Washington Utilities and Transportation Commission, 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); State of North Carolina ex rel. Utilities Commission v. General Telephone 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 therefor); Gulf Power Company v. Wilson, 597 So.2d 270, 273 (1992) (Public Service Commission was authorized to adjust rate of return within reasonable range to adjust for mismanagement); Wisconsin Public Service Corporation v. Citizen's Utility Board, Inc., 156 Wid.2d 611, 616 (1990) (prudence is a factor Public Service Corporation considers in setting utility rates and can affect the allowed return on equity).

The Attorney General raised three issues that she asserts demonstrate subpar management performance by NEGC and that she contends should be taken into account in setting the Company's ROE. First, she asserts that there is a conflict of interest issue involving the law firm that handles the Company's environmental remediation matters (Attorney General Brief at 52, 85; Attorney General Reply Brief at 20-23). The Attorney General appropriately acknowledges that environmental remediation matters are handled in a separate Department proceeding (Attorney General Brief at 91). We determine that there is insufficient record evidence in this proceeding to determine that there is a conflict of interest or to make a finding that the use of the specific law firm demonstrates subpar management performance. Nonetheless, the Attorney General receives copies of the Company's environmental remediation cost filings in the normal course of business. If the Attorney General is concerned that NEGC is inappropriately recovering costs through the LDAC, then she is free to pursue the issue in a separate proceeding.

Second, the Attorney General asserts that the Company failed to conduct a competitive bidding process for its revenue requirement witness and that such failure should be taken into consideration in setting the ROE (Attorney General Brief at 52 n.15, 83). In Section V.J.3., above, we determined that the Company undertook an adequate competitive bidding process and that its selection of the revenue requirement witness was reasonable and appropriate. Because of these findings, we determine that the Company's actions in this matter do not demonstrate subpar management performance.

Finally, the Attorney General raises concerns regarding the Company's actions in a separate Department-ordered audit proceeding (Attorney General Brief at 52, citing D.P.U. 08-110, at 14). On November 12, 2008, pursuant to G.L. c. 25, § 5E, the Attorney General filed a request for an independent audit of NEGC. On December 10, 2008, the Department commenced a proceeding and docketed that matter as D.P.U. 08-110. In its order opening D.P.U. 08-110, the Department stated that the purpose of the audit was to "ensure that financial data used by NEGC to calculate its revenue requirement in D.P.U. 08-35, were determined in accordance with generally accepted accounting principles." D.P.U. 08-110, Letter Order at 1 (March 11, 2009). The Department directed NEGC to hire an independent auditor to audit the Company's financial data and reporting. Based on the results of an RFP process, the Department selected an outside auditing firm to conduct the audit of NEGC. D.P.U. 08-110-A, Letter Order at 2 (January 13, 2010).

On August 12, 2010, NEGC submitted to the Department a copy of the auditor's final report, which the Company had received on August 5, 2010. D.P.U. 08-110, at 3. Based on a review of that report, the Department concluded that the auditor had, at the direction of NEGC and without the knowledge of either the Department or the Attorney General, "materially altered the scope, the intent, and the results" of the audit. D.P.U. 08-110, at 14. As a result of those alterations, the audit focused more on management capability than on the expressly ordered review of the financial data use in D.P.U. 08-35. In response, the Department directed NEGC to renegotiate a contract with the auditor for an audit to be conducted in accordance with the directives issued by the Department and in accordance with the scope of work and tasks outlined in the previously executed contract. D.P.U. 08 110, at 14. The Department also emphasized the need for the auditor to carry out its work freely and objectively, and ordered NEGC is to refrain from any inappropriate action that would compromise the auditor's independence. D.P.U. 08-110-A at 12 (January 26, 2011). In addition, the Department cautioned NEGC against either speaking on behalf of the independent auditor or expressing concerns regarding its qualifications. D.P.U. 08-110-A at 12 (January 26, 2011). We conclude that the actions taken by NEGC during the audit process demonstrate unacceptable management practices. Thus, we find it appropriate to take the Company's actions in this regard into consideration in establishing its ROE.

In determining the allowed ROE, the Department has also considered NEGC's use of fully reconciling mechanisms to recover NEGC's actual costs for certain cost categories outside of base rates. NEGC presently has in place fully reconciling mechanisms for a range of expense categories, including gas costs related to demand-side management and residential assistance adjustments, and supply-related bad debt that fully reconciles costs. NEGC also has a fully reconciling pension and post-retirement benefits other than pension mechanism. As a result of this Order, NEGC will retain these reconciling mechanisms and implement revenue decoupling, along with a fully reconciling TIRF and an Attorney General consultant cost mechanism. The use of the types of reconciling mechanisms that are approved by the Department in this Order or currently in place for NEGC produces a more timely and predictable recovery of costs compared to traditional ratemaking. By shortening the time between when NEGC incurs costs and when it recovers those costs in rates, the reconciling mechanisms reduce the possibility of earnings volatility. These financial benefits will lower the business risk for NEGC, which would tend to reduce the risk premium that prospective investors place on the Company.

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 9.45 percent is within a reasonable range of rates that will preserve the Company's financial integrity, will allow it to attract capital on reasonable terms and for the proper discharge of its public duties, will be comparable to earnings of companies of similar risk and, therefore, is appropriate in this case. In making these findings, we have considered both qualitative and quantitative aspects of the parties' various methods for determining the Company's proposed ROE, as well as the arguments of and evidence presented by the parties in this proceeding.

VII. RATE STRUCTURE

A. Rate Structure Goals

Rate structure is the level and pattern of prices charged to customers for their use of utility service. The rate structure for each rate class is a function of the cost of serving that rate class. As such, rate structure is the design of rates so that the cost to serve a rate class is recovered to the extent possible, considering what are often competing rate structure goals in the rates charged to that class. Utility rate structures must be efficient and simple, and ensure continuity of rates, fairness among rate classes, and corporate earnings stability. 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. The Department must balance these often competing goals to develop the appropriate rate structure. Efficiency means that the rate structure is designed to 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 energy needs. The least-cost method of fulfilling each consumer's needs should also be the least-cost means for society as a whole. Thus, efficiency in rate structure means setting cost-based rates that recover the cost to society of the consumption of resources used to produce the utility service. D.P.U. 10-55, at 536; D.T.E. 03-40, at 365; D.T.E. 01-56, at 135; D.T.E. 02-24/25, at 252-253.

A rate structure achieves the goal of simplicity if it is easily understood by consumers. Rate continuity means that changes to rate structure should be gradual to allow consumers to adjust their consumption patterns in response to a change in structure. Fairness means that no class of consumers should pay more than the costs of serving that class. Earnings stability means that the amount a company earns from its rates should not vary significantly over a period of one or two years. D.P.U. 10-55, at 536; D.T.E. 03-40, at 365; D.T.E. 01-56, at 135; D.T.E. 02-24/25, at 252-253.

There are two steps in determining rate structure: cost allocation and rate design. The cost allocation step assigns a portion of the company's total costs to each rate class through the use of a cost of service study ("COSS"). The COSS represents the cost of serving each class at equalized rates of return given the company's level of total costs. D.P.U. 10-55, at 536; D.T.E. 03-40, at 367; D.T.E. 01-56, at 135; D.T.E. 01-50, at 29; D.P.U. 96-50 (Phase I) at 135.

There are four steps to developing a COSS. The first step is to classify costs by category, according to the service function they provide – either (1) production and storage, or (2) transmission and distribution. The second step is to classify expenses in each functional category according to the factors underlying their causation (i.e., demand, energy, or customer-related). The third step is to identify the most appropriate allocator for costs in each classification within each function. The fourth step is to allocate all of the company's costs to each rate class based upon the cost groupings and allocators chosen, and to sum these allocations in order to determine the total costs of serving each rate class. D.P.U. 10-55, at 536-537; D.T.E. 03-40, at 366-367; D.T.E. 01-56, at 136; D.T.E. 98-51, at 131-132.

The results of the COSS are compared to normalized test year revenues. If differences in these amounts are small, 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 relatively high, then, for reasons of continuity, the revenue increase or decrease may be allocated so as to reduce the difference in rates of return, but not to equalize them in a single step. See D.T.E. 01-56, at 135; D.T.E. 01-50, at 29.

As the previous discussion indicates, the Department does not determine rates based solely on costs to serve, but also explicitly considers the effect of its rate structure decisions on the amount customers are billed. For instance, the pace at which fully cost-based rates are implemented depends in part on the effect of the changes on customers. Additionally, the Department has ordered the establishment of special subsidized rate classes for certain low-income customers. In moving toward our goal of efficiency, the Department also considers the effect of such rates on low-income customers. D.P.U. 10-55, at 537; D.T.E. 03-40, at 367; D.T.E. 01-56, at 137; D.T.E. 01-50, at 29-30.

In order to reach fair decisions that encourage efficient utility and consumer actions, the Department's rate structure goals must balance the often divergent interests of various customer classes and prevent any class from subsidizing another unless a clear record exists to support such subsidies – or they are required by statute, e.g., G.L. c. 164, § 1F(4)(I). The Department reaffirms its rate structure goals that result in rates that are fair, cost-based, and enable customers to adjust to changes. D.P.U. 10-55, at 538; D.T.E. 03-40, at 368; D.T.E. 01-56, at 136-137; D.T.E. 01-50, at 30.

B. Allocated Cost of Service Study

1. Introduction

NEGC performed an allocated cost of service study ("COSS") as a basis to assign or allocate costs to customer rate classes (Exh. NEGC-DAH-1, at 13). The COSS identified each item contributing to NEGC's revenue requirement for distribution service (Exh. NEGC-DAH-1, at 13). The COSS used a three-step process to allocate costs to the various rate classes (Exh. NEGC-DAH-1, at 14). The first step was functionalization, where the plant investment costs and operating expenses were categorized by the operational functions with which they are associated (i.e., gathering, storage, transmission, distribution, and customer service) (Exh. NEGC-DAH-1, at 14). The second step was classification, where the functional cost elements were classified by the factor of utilization most closely matching cost causation (i.e., customer, capacity, or commodity related) (Exh. NEGC-DAH-1, at 14). The final step was the allocation of the functionalized and classified costs to the various rate classes (Exh. NEGC-DAH-1, at 14). This allocation is accomplished through direct assignment, the use of external allocation factors, and the use of internal allocation factors (Exh. NEGC-DAH-1, at 14, 15).[212]

The COSS used production, distribution, local distribution adjustment, and gas cost as the functions to which plant investment costs and operating expenses were categorized in the first step (Exh. NEGC-DAH-1, at 16). The production function captured the costs related to NEGC's propane and LNG facilities (Exh. NEGC-DAH-1, at 16). The distribution function captured all costs to be recovered through base distribution rates (Exh. NEGC-DAH-1, at 16). The local distribution adjustment function included the pension and employee benefit costs, which are recovered through the LDAC, and the gas cost function captured all purchased gas costs (Exh. NEGC-DAH-1, at 16). The three cost classifications used in the second step of the COSS were demand, customer, and commodity (Exh. NEGC-DAH-1, at 16).

According to the Company, its production and storage plant costs were classified as "demand" and allocated to each rate class on a peak demand basis, using the sales peak proportional responsibility factor[213] (Exh. NEGC-DAH-1, at 17). NEGC's distribution plant

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212 External allocation factors were developed using data from the Company's records, whereas internal allocation factors were generated by the COSS using the outputs from external allocators (Exh. NEGC-DAH-1, at 15).

213 The proportional responsibility factor is a capacity allocator that considers the monthly variation in sales by customer class; months with higher levels of usage are given more weight than months with lower levels of usage. Gary H. Grainger, The Proportional

costs were classified as either "demand" or "customer" related, where the demand-related costs were allocated to each rate class on the basis of a proportional responsibility factor and the customer-related costs were allocated to each rate class on a customer-related basis, such as the number of customers in a rate class (Exh. NEGC-DAH-1, at 18). Common costs, such as land, rights-of-way, and other equipment, were allocated to each rate class using internal factors based on the directly-assigned costs (Exh. NEGC-DAH-1, at 18). NEGC classified and allocated the intangible plant costs (e.g., customer information system) to each rate class based on the number of customers in each rate class (Exhs. NEGC-DAH-1, at 19; AG-4-1 DAH(H)). The general plant costs were classified and allocated to each rate class on the basis of an internal factor that is based on the classification and allocation of production, storage, and distribution plant costs (Exh. NEGC-DAH-1, at 19). Meter costs were allocated to the rate classes based on a meter factor developed from data supplied by NEGC for both the Fall River and North Attleboro service areas (Exh. NEGC-DAH-1, at 18). Production and storage costs were classified as demand related and allocated to each rate class based on the sales peak proportional responsibility factor (Exh. NEGC-DAH-1, at 19).

All customer account expenses were classified as customer-related costs (Exh. NEGC-DAH-1, at 20). Meter reading costs were allocated to each rate class based on the amount of time taken to read meters (Exh. NEGC-DAH-1, at 20). Customer records and

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Responsibility Method of Capacity Cost Allocation, PUBLIC UTILITIES FORTNIGHTLY, November 9, 1972. The sales peak proportional responsibility factor is a special case of the proportional responsibility method that is based only on sales throughput and on the peak period loads (Exh. NEGC-DAH-1, at 17).

collections costs were allocated based on a blended factor based on the type of costs included in the account (Exh. NEGC-DAH-1, at 20). Uncollectible expenses were allocated on the basis of account write offs (Exh. NEGC-DAH-1, at 20). Labor-related administrative and general costs, injuries and damages, and pension and benefits were allocated based on an internal labor factor (Exh. NEGC-DAH-1, at 20). Property insurance costs were allocated on the basis of total plant, while maintenance of general plant and repair expenses were allocated on an internal factor (Exh. NEGC-DAH-1, at 20). Depreciation expenses were allocated based on the related plant, and taxes other than income taxes were allocated on a plant or labor basis, depending on the type of tax (Exh. NEGC-DAH-1, at 20). The remaining rate base costs were classified and allocated on internal factors, with the exception of customer deposits, which were classified as customer costs and allocated on a factor representing the balances by rate class (Exh. NEGC-DAH-1, at 19).

According to NEGC, the results of the COSS show that the Company is currently earning an overall return of 1.73 percent, with class returns ranging from negative 11.64 percent for residential non-heating customers to 30.57 percent for large high load factor C&I customers (Exhs. NEGC-DAH-1, at 21; NEGC-DAH-8, at 1). The Company also states that residential non-heating and residential heating customers have class returns below the system average, while all of the C&I customers show class returns in excess of the system average (Exhs. NEGC-DAH-1, at 21; NEGC-DAH-8, at 1).

2. Positions of the Parties

a. Attorney General

The Attorney General contends there are misspecifications of some important allocators in the Company's COSS, namely the allocation of service plant costs and Account 874, "operation of mains and services" costs (Attorney General Brief at 92, citing Exh. AG-LS-1, at 2, 3). The Attorney General claims the allocation of service plant cost was not based on data regarding the relative cost of services for each class, but instead was based on the average cost of meter plant serving each class (Attorney General Brief at 92, citing Exh. AG-4-1(DAH)(C); RR-NEGC-1). According to the Attorney General, the result of the Company's averaging residential and small commercial customers is an over-allocation of service plant costs to residential customers (Attorney General Brief at 92).

Regarding Account 874, "operation of mains and services," the Attorney General claims the allocation method utilized by the Company assumes that the portion of the Account 874 expense that is caused by the operation of services is proportional to the relationship between service plant and mains plant (Attorney General Brief at 92-93, citing Exh. AG-LS-1, at 4). The Attorney General argues that this assumption is erroneous and not supported by the record evidence (Attorney General Brief at 93, citing Exh. AG-LS-1, at 4). As such, the Attorney General initially proposed modifying the Account 874 allocator to assume there were no expenses related to services in this account (Attorney General Brief at 93, citing Exh. AG-LS-1, at 8). The Attorney General subsequently indicated that some expenses in the account are related to services, but maintains that too much weight was placed on services in the account (Attorney General Brief at 93; Tr. 4, at 474, 485). Therefore, the Attorney General requests that the Company more carefully consider the allocation of service plant and of Account 874 in the next rate case (Attorney General Brief at 94).

b. The Company

NEGC argues that the Company's COSS uses the same methodologies as those presented in its prior COSS, which was reviewed and approved in D.P.U. 08-35 (NEGC Brief at 104). Therefore, the Company argues that the COSS in the instant proceeding is consistent with Department precedent (NEGC Brief at 104).

Regarding the allocation of service plant, the Company contends it used a weighted customer factor to allocate services based on average meter costs using the small commercial customer costs as the index for weighting (NEGC Brief at 105, citing Exh. NEGC-DAH-1, at 18). NEGC avers that combining the costs for the residential and small commercial customers was appropriate given the Company's representation of the service costs for these customers (NEGC Brief at 105).

In response to the Attorney General's contention regarding the allocation of Account 874, the Company claims its method of allocating Account 874 expenses is appropriate (NEGC Brief at 105). NEGC argues that the Attorney General's claim that Account 874 has no expenses related to services is based on two faulty rationales: (1) that the operation activities booked in this account have little to do with services since only two of the categories of costs for this account explicitly reference services, and (2) that the Company has an exceptionally low proportion of mains plant to services plant resulting from a disallowance of mains plant in North Attleboro Gas's rate base (NEGC Brief at 106, citing Exh. AG-LS-1, at 4, 6; Tr. 4, at 474). NEGC counters that pursuant to D.P.U. 08-35, the plant amount that was previously disallowed was approved for reclassification as plant in service (NEGC Brief at 106, citing D.P.U. 08-35, at 28). As such, the Company asserts that the Attorney General's claims with respect to the Account 874 allocations are inappropriate (NEGC Brief at 106).

3. Analysis and Findings

The Attorney General has expressed concern regarding how the Company allocated certain costs, specifically those associated with service plant and the operation of mains and services. The Attorney General proposes that NEGC carefully consider these two allocations in its next distribution general rate case (Attorney General Brief at 93-94).

The record in this proceeding demonstrates that NEGC has conducted a COSS which utilizes the same methodologies as those presented in the Company's prior COSS, which was approved in D.P.U. 08-35 (Exhs. DPU-NEGC-3-6; AG-1-102, Att.). NEGC functionalized and classified costs in a manner consistent with Department precedent, and the allocation factors used were the same as those used in the Company's last COSS (Exhs. DPU-NEGC-2-7; DPU-NEGC-3-6). Further, the specific modifications proposed by the Attorney General to the two allocation factors in question do not result in any material differences in the rate design proposed by the Company (Attorney General Brief at 93-94; Tr. 4, at 482-483).

The Department has evaluated NEGC's proposed allocated COSS and finds that it has assigned the appropriate costs to each rate class consistent with Department precedent for cost allocation. D.P.U. 10-55, at 535; D.T.E. 03-40, at 369; D.T.E. 01-56, at 138; D.P.U. 96-50

(Phase I) at 136. Nonetheless, the Attorney General has raised some appropriate considerations regarding the allocation factors that the Company used to assign service plant costs to each rate class, and as such, the Department directs the Company in its next base distribution rate case to further research and analyze its selection of allocation factors for these costs to ensure that service plant costs are being apportioned ratably on the basis of cost causation. The Department directs NEGC, in its compliance filing, to re-run its allocated COSS to allocate its costs and expenses as approved in this Order.

C. Marginal Cost Study

1. Introduction

The use of a marginal cost study facilitates the development of rates that provide consumers with price signals that accurately represent the costs associated with consumption decisions. D.P.U. 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 the marginal cost study allow consumers to make informed decisions regarding their use of utility services, promoting efficient allocation of societal resources. D.P.U. 10-55, at 524; D.P.U. 09-30, at 378; D.P.U. 08-35, at 227; D.P.U. 07-71, at 159. According to NEGC, the Company's marginal cost study is an update to the study that was filed by the Company in D.P.U. 08-35 and approved by the Department on February 2, 2009 (Exh. NEGC-JDS-2, at 1). The updates performed by the Company in the current marginal cost study comprise (1) an increase in the marginal cost components to reflect appropriate measures of inflation, and (2) an update of the fixed carrying charge inputs to reflect values that NEGC presents in the instant proceeding (Exh. NEGC-JDS-2, at 1-2).

2. Description of Marginal Cost Study

NEGC relied upon the marginal cost estimates of capacity-related distribution plant additions, capacity-related distribution operations and maintenance expenses, and marginal loading factors[214] that were prepared in 2008 for D.P.U. 08-35 (Exh. NEGC-JDS-2, at 2). According to the Company, the 2008 study was prepared by applying rigorous and well-documented statistical techniques in conformance with the Department's directives in several decisions (Exh. NEGC-JDS-2, at 2, citing D.T.E. 05-27; D.T.E. 03-40; D.T.E. 02-24/25).

More specifically, NEGC indicated that in updating the 2008 marginal cost study, the Company escalated the plant-related marginal cost components to reflect changes between the previous marginal cost study and the current marginal cost study as well as the expense-related marginal cost components, to reflect cost changes between the previous marginal cost study and the current marginal cost study (Exh. NEGC-JDS-2, at 2-3). Next, the Company updated various input values related to the calculation of the fixed carrying charge and calculation of the Company's total loss-adjusted marginal costs by rate class to reflect values consistent with the Company's proposed revenue requirement in the instant proceeding (Exh. NEGC-JDS-2, at 3).[215]

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214 The Company indicated that marginal cost estimates and marginal loading factors were estimated using data from the Company's annual reports to the Department for the years 1979-2007 (Exh. NEGC-JDS-2, at 2).

215 The input updates comprise capital structure, cost of capital, income tax rate, property tax rate, property insurance rate, inflation rate, distribution plant balances, cash working capital allowance rate, distribution losses, annual normalized usage by class,

The Company states that the use of dummy variables in developing its marginal cost equations was necessary to explain meaningful shifts in data and cost structure that could not be explained with identifiable independent variables (Tr. 2, at 238-239; RR-DPU-18). Based on its analysis, NEGC estimated the total loss-adjusted marginal cost of service to be $116.43 per dekatherm of demand plus $0.2388 per dekatherm of sendout (Exhs. NEGC-JDS-2, at 4; NEGC-JDS-2-5, at 2). Based on this estimate, NEGC developed class-specific marginal costs rates per dekatherm of sendout (Exhs. NEGC-JDS-2, at 4; NEGC-JDS-2-5, at 2, 3).

3. Positions of the Parties

The Company asserts that it prepared a marginal cost study in accordance with Department precedent following sound, rigorous techniques and procedures, and based on a set of clear directives and standards related to marginal cost studies in prior Department Orders (Company Brief at 98, citing D.T.E. 05-27; D.T.E. 03-40; D.T.E. 02-24/25). The Company also maintains that the marginal cost study was prepared by updating the analysis relied upon and approved by the Department in its prior rate case proceeding (Company Brief at 98, citing D.P.U. 08-35). No other party commented on this matter on brief.

4. Analysis and Findings

As an initial matter, we note that the Company's marginal cost study is an update of the study presented in D.P.U. 08-35. In D.P.U 08-35, at 229, the Department approved the

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and peak day demand as a percent of annual demand (Exh. NEGC-JDS-2, at 3, Table NEGC-JDS-1).

Company's proposed marginal cost study, noting that it incorporated sufficient detail to allow a full understanding of the methods used to determine the marginal cost estimates. In D.P.U. 08-35, at 229, the Department found that in its marginal cost study, the Company included the determination of six cost components: (1) the marginal cost of capacity-related distribution plant; (2) the marginal capacity-related operations expense; (3) the marginal capacity-related maintenance expense; (4) the marginal general plant expense; (5) the marginal administrative and general expense; and (6) the marginal material and supplies expense. Further, the Department found that NEGC (1) used econometric analysis, (2) used multiple variable regression equations, and (3) performed appropriate diagnostic tests to detect potential statistical problems. D.P.U. 08-35, at 230. Finally, we note that in preparing the instant marginal cost study update, the Company used 29 years worth of data (Exh. NEGC-JDS-2, at 2).

As the Company's proposed marginal cost study is effectively an update of the previously-approved 2008 marginal cost study, the Department approves the Company's proposed marginal cost study. Nonetheless, during the proceeding, the Attorney General questioned the Company's reliance on dummy variables that did not have cost causative explanations underlying them (Exh. AG-LS-1, at 12-13). The Attorney General asserted that the extensive use of many dummy variables to make the regression equations fit the data casts doubt on the underlying relationship between the dependent and independent variables (Exh. AG-LS-1, at 13). The Company indicated that the use of these variables was intended to explain meaningful shifts in data and cost structure that could not be explained with identifiable independent variables (see Tr. 2, at 238-239; RR-DPU-18).

While the use of both dummy variables and autoregressive terms is an acceptable method in developing regression analyses, the Department cautions the Company that extensive use of these tools may not lead to the development of a model with the best predictive powers. The Department, therefore, directs NEGC, in its next rate case, to develop a marginal cost study that limits the number of dummy variables and autoregressive terms or, alternatively, provide justification as to why NEGC was unable to identify causal variables.

D. Rate Design

1. Introduction

The Company states that class revenue targets were determined based on the results of the COSS (Exh. NEGC-JDS-1, at 26). The study determined fully-allocated costs at equalized rates of return for each of NEGC's rate classes (Exh. NEGC-JDS-1, at 26). According to NEGC, the fully-allocated total Company base-revenue requirement is net of the costs recovered through the CGAC and LDAC cost recovery mechanisms (Exh. NEGC-JDS-1, at 26-27). The Company used the class-specific, fully-allocated base distribution revenue requirement at the Company's proposed return on rate base as the initial basis for setting class revenue targets; nonetheless, based on the rate design principles of earnings stability and continuity, NEGC also considered the rate impacts on each class as a whole from increasing the revenue targets (Exh. NEGC-JDS-1, at 27).

The Company designed its base rates to recover a total base distribution revenue requirement of $28,545,352 (Exhs. NEGC-JDS-1, at 26; NEGC-DAH-12). The Company used the following steps to determine class revenue targets. First, NEGC calculated current total class revenues by using pro forma normalized billing determinants and current distribution rates (Exhs. NEGC-JDS-1, at 27; NEGC-JDS-1-2). Second, NEGC determined the amount of the total revenue requirement to be assigned to each rate class based on the results of the COSS (Exhs. NEGC-JDS-1, at 27; NEGC-JDS-1-2). Third, the Company calculated class revenue increase impacts by comparing for each rate class current revenues to proposed revenues, and set a class revenue increase cap to limit the amount of the increase assigned to any class to satisfy the rate design goal of continuity (Exh. NEGC-JDS-1, at 27, 29-30). Fourth, the Company assigned any revenue shortfalls that result from the class revenue increase cap to all classes whose revenue increase was below the cap to determine the final base revenue targets by class (Exh. NEGC-JDS-1, at 27).

The Company calculated total revenues at current rates by summing pro forma base revenues, plus LDAF revenues, plus total imputed GAF revenues (Exh. NEGC-JDS-1, at 27-28). To calculate overall class revenue increase impacts at the proposed revenue targets, NEGC adjusted base revenues for low-income classes R-2 and R-4 to eliminate the difference between the current discounted R-2 and R-4 rates and the current corresponding regular R-1 and R-3 rates (Exh. NEGC-JDS-1, at 28). The Company calculated total fully-allocated costs by summing fully-allocated base costs, and GAF and LDAF revenues at current rates (Exh. NEGC-JDS-1, at 28).

Class revenue increase impacts were determined by comparing for each rate class current revenues to proposed revenues (Exh. NEGC-JDS-1, at 27). To do this, NEGC calculated the difference between fully-allocated base rate costs, plus proposed LDAF and GAF revenues, by class ("total potential increase") and compared the difference to pro forma base revenues plus pro forma LDAF revenues and imputed GAF revenues (Exh. NEGC-JDS-1, at 29). NEGC then calculated the percentage change that the class-specific total potential increases represent relative to the current total class revenues (Exh. NEGC-JDS-1, at 29). To maintain rate continuity and stability, the Company proposed that the percent increase in base rate plus LDAF and GAF revenues should be limited to 120 percent of the Company average increase (Exhs. NEGC-JDS-1, at 30; DPU-NEGC-2-11).

The Company stated that applying the 120-percent cap created a revenue requirement shortfall as a result of capping the increases to rate classes R-1, R-2, R-3, and R-4 (Exh. NEGC-JDS-1, at 30-31). NEGC allocated the resulting shortfall of $1,151,602 to all classes that were below the cap by calculating the difference between the capped percent increase and the total potential percent increase for each class, weighted by the total pro forma class revenues (Exh. NEGC-JDS-1, at 30-31). As the final step, the Company determined the base revenue target increase for each class by subtracting the LDAF and GAF revenue increase from the total class revenue increase, which included each class's assigned share of the revenue shortfall that resulted from setting a cap for the increase to a class (Exh. NEGC-JDS-1, at 31). NEGC added the increase to the base revenue targets for each class to the pro forma test year base revenues to determine total class revenue targets (Exh. NEGC-JDS-1, at 31).

NEGC used the following steps to design base rates that would recover each rate class's revenue target. First, the Company determined the appropriate level of customer charges (Exh. NEGC-JDS-1, at 31). Second, the Company determined the appropriate ratio of peak period rates to off-peak period rates (Exh. NEGC-JDS-1, at 32). Third, the Company determined the appropriate rate differential between head block and tail block rates (Exh. NEGC-JDS-1, at 32). Fourth, NEGC calculated the final rates (Exh. NEGC-JDS-1, at 32). In addition to calculating the final rates, the Company determined the low-income discounted rates, and calculated the revenue shortfall resulting from the low-income discount (Exh. NEGC-JDS-1, at 32, 36).

To determine the appropriate level of customer charges for each class, the Company considered (1) the fully-allocated unit customer costs calculated in the COSS, (2) a survey of Massachusetts local gas distribution customer charges, (3) rate continuity, and (4) customer impacts (Exh. NEGC-JDS-1, at 32). NEGC determined that setting customer charges at 110 percent of current customer charges would avoid excessive levels of bill impact disparities within each class (Exh. NEGC-JDS-1, at 33 & n.29). According to NEGC, the proposed customer charges for all classes except G-43/T-43 and G-53/T-53 are significantly below the allocated unit customer cost to serve because the customer rate impact presented rate continuity concerns (Exh. NEGC-JDS-1, at 34). The Company calculated class customer charge revenues by multiplying the proposed customer charges by the test year class customer counts (Exh. NEGC-JDS-1, at 34). To determine the quantity-based revenue target, NEGC subtracted the class customer charge revenues from the class revenue target (Exh. NEGC-JDS-1, at 34).

According to NEGC, the base rate seasonal ratios were set in a manner that would promote efficiency in pricing, that would be understandable to customers, and would not produce undue customer impacts (Exh. NEGC-JDS-1, at 34). NEGC also states it maintained similar seasonal ratios to those used in developing rates in the Company's previous rate case, D.P.U. 08-35 (Tr. 2, at 187). Seasonal ratios were set such that the peak-to-off-peak ratio is higher for classes that have a higher proportion of their annual use in the peak period, such as residential heating and low-load-factor classes (Tr. 2, at 187). The Company set the low-income discount at 20.71 percent for R-2 customers and 22.18 percent for R-4 customers (Exh. NEGC-JDS-1, at 36). The Company stated that a 20.71 and 22.18 percent discount produced reasonable and appropriate low-income base rates given the Department's recent Orders concerning low-income discounted rates (Exhs. DPU-NEGC-2-13; DPU-NEGC-2-13, citing New England Gas Company, D.P.U. 10-47 (2010)). NEGC will recover the revenue shortfall that results from the discounted low-income rates through the RAAF (Exh. NEGC-JDS-1, at 36).

NEGC has also proposed an inclining block rate structure that is seasonally differentiated to comply with directives established by the Department in D.P.U. 09-30 and D.P.U. 10-55 (Exhs. NEGC-JDS-1, at 35; DPU-NEGC-3-10).[216] The Company set tail block

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[216] A seasonally differentiated rate structure provides separate rates for peak and off-peak seasons as defined in n.12, above.

rates for each season at 105 percent of the average variable rate for that season, and then the head block rate was calculated to recover the remaining variable revenues (Exh. NEGC-JDS-1, at 35). The size of the head blocks was also selected in a manner that resulted in approximately 25 percent of total class seasonal therms in the head block (Exhs. NEGC-JDS-1, at 35; DPU-NEGC-3-10).

2. Positions of the Parties

a. Attorney General

The Attorney General argues that the Department should reject the inclining block rates proposed by the Company (Attorney General Brief at 94). The Attorney General claims that if inclining block rates are adopted, increased natural gas consumption will be penalized without regard to efficiency or the possibility of avoided usage (Attorney General Brief at 94). As such, the Attorney General posits that it is unlikely that inclining block rates will result in customers using less gas than if they were charged flat rates in each season (Attorney General Brief at 94). According to the Attorney General, there is no evidence that inclining block rates, as proposed by NEGC, are supported by any cost data, or that they will increase energy efficiency (Attorney General Brief at 95).

The Attorney General also contends that inclining block rates result in complication and customer confusion without providing an efficient price signal (Attorney General Brief at 95, citing Exh. AG-LS-1, at 12). Therefore, the Attorney General maintains that the Department should reject NEGC's use of inclining block rates (Attorney General Brief at 95).

b. Network

The Network argues that NEGC's low-income discount applicable to R-2 and R-4 rate classes should be raised to a uniform 25 percent (Network Brief at 2; Network Reply Brief at 2). As part of its argument, the Network references D.P.U. 10-46, at 17, where the Department raised National Grid's low-income discount rates to 25 percent (Network Brief at 1). The Network claims that the reasons cited by the Department in D.P.U. 10-46 are applicable in the instant case, namely, (1) to simplify the low-income discount, (2) to reduce customer confusion, (3) to provide ease in the Department's administering of the discount, and (4) to be consistent with the discount established for National Grid's electric utility[217] (Network Brief at 1, citing D.P.U. 10-46, at 17).

Further, the Network contends that raising the low-income discount to 25 percent would result in substantial benefits to low-income customers while having minimal impacts on non-low-income customers (Network Brief at 2, citing Exh. LI-1-3-(b); Network Reply Brief at 1). The Network claims an increase in the discount would reduce the difficult burden of energy costs for low-income customers in Fall River, a community heavily distressed as a result of the recession (Network Brief at 2).

217 The Network claims that most low-income NEGC customers are also customers of National Grid (electric) (receiving a 25-percent discount) or in close local proximity to National Grid (gas) customers (also receiving a 25-percent discount) (Network Brief at 1). By making NEGC's low-income discount 25 percent, the Network argues that the principles of consistency, simplification, and reducing customer confusion are achieved (Network Brief at 1-2).

c. Company

NEGC does not explicitly address the Attorney General's argument regarding inclining block rates, however, the Company claims that the proposed rate design in the instant proceeding is both reasonable and consistent with the Department's rate structure goals and directives set forth in D.P.U. 09-30 and D.P.U. 09-39 (Company Brief at 99, citing Exh. NEGC-JDS-1, at 25).

Regarding the Network's request to increase the low-income discount to a uniform 25 percent, NEGC argues its proposed discount rates are appropriate, and that a uniform 25-percent discount should not be adopted (Company Brief at 102, 104). NEGC claims that the discounts proposed for the R-2 and R-4 low-income rate classes in the instant proceeding are consistent with Department directives established in D.P.U. 08-4, D.P.U. 09-39, as well as with the recent approval of the Company's low-income compliance filing tariffs in D.P.U. 10-47 (Company Brief at 102). The Company is skeptical that there is any significance to the ostensible benefits of a uniform 25-percent discount, arguing that in the three decades that low-income discounts have been offered, no two gas or electric utility companies have had consistent discount rates until the recent change to National Grid's discount (Company Brief at 103 n.16, citing D.P.U. 10-46).

Further, the Company claims that any benefits resulting from the Network's proposal would be outweighed by the costs, which are borne by the Company's non-low-income customers (Company Brief at 103). Specifically, NEGC points to the fact that the non-low-income customers would incur a RAAF of over $0.06 per therm in order to recover the revenue shortfall associated with low-income customers (Company Brief at 103). The Company also notes that this RAAF would be more than three times the RAAF charged to National Grid customers (Company Brief at 103).

3. Analysis and Findings

The Department must determine, on a rate class by rate class basis, the proper level to set the customer charge and delivery charge for each rate class, based on a balancing of our rate design goals, which are discussed above. The rate-by-rate analysis is discussed below. The Department's long-standing policy regarding the allocation of class revenue requirements is that a company's total distribution costs should be allocated on the basis of equalized rates of return. See, e.g., D.T.E. 02-24/25, at 256; D.T.E. 01-56, at 139; D.P.U. 92-250, at 194. This allocation method satisfies the Department's rate structure goal of fairness. Nonetheless, the Department must balance its goals of fairness and continuity. To do this, we have reviewed the changes in total revenue requirements by rate class and bill impacts by consumption level within rate classes. Based upon our review, we accept the Company's proposal that to address the goal of continuity, no rate class should receive an increase greater than 120 percent of the overall distribution rate increase (Exh. NEGC-JDS-1, at 30-31). The Department finds that the 120-percent cap is an appropriate cap that meets our rate structure goals of fairness and continuity by ensuring that the final rates for each rate class represent or approach the cost to serve that class, that the limited level of cost subsidization created by the cap will not unduly distort rate efficiencies, and that the magnitude of change to any one class is contained within reasonable bounds (Exhs. NEGC-JDS-1, at 30; DPU-NEGC-2-11). The Department directs the Company to calculate the rate increase cap as shown on Schedule 10.

The remaining revenue increase (i.e., the amount above the 120-percent cap) will be allocated first to those rate classes that would, at equalized rates of return, receive a rate decrease, but only up to the amount that would eliminate such rate decrease. The allocation will be based on the ratio of each class's decrease to the total decrease for these classes. Any remaining revenue increase will be recovered on a pro rata basis based on test-year base revenues, from those classes whose revenue requirement falls below the 120-percent rate cap and that, at equalized rates of return, would not receive a rate decrease.

In the instant proceeding, NEGC has proposed inclining block rates that are seasonally differentiated for all rate classes (Exhs. NEGC-JDS-1, at 34-35; NEGC-JDS-1-12, at 11; DPU-NEGC-2-12; DPU-NEGC-3-10). In D.P.U. 08-35, the Department directed NEGC and all other natural gas and electric distribution companies to design distribution rates using an inclining block structure. D.P.U. 08-35, at 249. The Department finds that the design of distribution rates should be aligned with important state, regional, and national goals to promote the most efficient use of society's resources and to lower customers' bills through increased end-use efficiency. To best meet these goals, rates should have an inclining block rate structure and any resulting loss in revenues from declining sales should be recovered through a decoupling mechanism as discussed in Section II., above. See generally D.P.U. 07-50-A.

The Department finds that NEGC's proposed inclining block rate structure best meets our goals to promote the efficient use of society's resources and lower customers bills through increased end-use efficiency, and is consistent with the Department's directives in D.P.U. 07-50-A, D.P.U. 08-35, and D.P.U. 09-30. Therefore, we deny the Attorney General's request to reject the Company's inclining block rate structure. Further, we find that the following elements of NEGC's proposal are consistent with our goal to promote end-use efficiency: (1) to set the head block sizes for each rate class and for each season at a level at which approximately 25 percent of total class seasonal billed sales fall in the head block; (2) to then set the tail block rates for each season at 105 percent of the average variable rates for that season; and (3) to set the head block rates at a level that would recover the remaining target revenues to be collected through the variable energy charges for that season. Therefore, the Department approves the Company's proposed method for establishing the size of the head blocks, the tail blocks, and their respective rates. The Department also finds that the proposed allocation of class revenue requirements between the peak and off-peak seasons is appropriate. The seasonal rates provide appropriate price signals for customers and, adhering to the rate structure goals of fairness and cost causation, assign higher ratios for those classes with greater levels of use in the peak period (Tr. 2, at 187-188).

To determine the appropriate customer charges the Department must balance the competing goals of: (1) lowering customers' bills through increased end-use efficiency; and (2) rate continuity. The Department finds that NEGC's proposal to set customer charges at 110 percent of current customer charges provides the appropriate balance of these goals. The specific rate-by-rate analysis is discussed in the following section.

Regarding the Network's proposal to increase the low-income discount to a uniform 25 percent, the Department must fully consider and weigh the benefits to low-income residential customers and the change in costs to non-low-income customers. This particular issue was raised in D.P.U. 10-47, where the Network recommended that all gas distribution companies increase the low-income discount to 25 percent. D.P.U. 10-47, at 18. In that proceeding, the Department found that an increase in the discount level was beyond the scope of the proceeding, and for that reason rejected the Network's proposal. D.P.U. 10-47, at 18. In the instant case, the Department has reviewed the effects of increasing the low-income discount to 25 percent and has determined the overall bill impacts demonstrate a significant benefit to low-income customers as compared to a modest increase in the bill impacts of non-low-income customers (Exhs. LI-1-3; LI-1-3(b)).[218] In addition, the Department notes that implementing a uniform 25 percent discount will encourage administrative efficiencies. As

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218 The Company asserts that the uniform 25-percent discount proposed by the Network should be rejected because it will result in a RAAF that is more than three times the RAAF charged to National Grid customers (Company Brief at 103). NEGC's current RAAF is \$0.0707 per therm, while National Grid's current RAAFs are \$0.0193 per therm and \$0.0165 per therm for Boston Gas and Colonial Gas, respectively. New England Gas Company, D.P.U. 10-GAF-P6, Letter Order at 2 (October 29, 2010); D.P.U. 10-55, Compliance Filing Stamp Approval (November 18, 2010). Because NEGC's RAAF is already three times higher than National Grid's RAAF, the argument is non-persuasive. Further, the relevant comparison is to consider the impact any change would have on NEGC's current RAAF and, in fact, under the rate design approved in this Order, the Company's RAAF will be less than \$0.070 per therm.

such, the Department approves the Network's request to increase NEGC's low-income discount to a uniform 25 percent.

E. Rate by Rate Analysis

1. Rate R-1, Rate R-2, Rate R-3, and Rate R-4

a. Introduction

Rate R-1 is available to all residential customers for domestic non-heating purposes in private dwellings and individual apartments (Exh. NEGC-JDS-1-15, Proposed M.D.P.U. No. 1003A). Rate R-1 is also available for all non-heating uses by residential condominiums to the extent permitted by applicable regulations (Exh. NEGC-JDS-1-15, Proposed M.D.P.U. No. 1003A). Rate R-2 is a subsidized rate that is available at single locations to all residential customers for domestic non-heating purposes in private dwellings and individual apartments (Exh. NEGC-JDS-1-15, Proposed M.D.P.U. No. 1004A). A customer will be eligible for this rate upon verification by NEGC of the customer's participation in any means-tested public benefit program or verification of eligibility for the low-income home energy assistance program or its successor program, for which eligibility does not exceed 60 percent of the median income in Massachusetts based on a household's gross income or other criteria approved by the Department (Exh. NEGC-JDS-1-15, Proposed M.D.P.U. No. 1004A). See also Investigation Commencing a Rulemaking Pursuant to 220 C.M.R. § 2.00 et seq., D.P.U. 08-104 (2008).

Rate R-3 is available to all residential customers for domestic heating purposes in private dwellings and individual apartments (Exh. NEGC-JDS-1-15, Proposed

M.D.P.U. No. 1005A). Rate R-3 is also available for all uses by residential condominiums to the extent permitted by applicable regulations (Exh. NEGC-JDS-1-15, Proposed M.D.P.U. No. 1005A). Rate R-4 is a subsidized rate that is available at single locations to residential customers for domestic heating purposes in private dwellings and individual apartments (Exh. NEGC-JDS-1-15, Proposed M.D.P.U. No. 1006A). The same eligibility criteria as for Rate R-2 apply (Exh. NEGC-JDS-1-15, Proposed M.D.P.U. No. 1006A). See also D.P.U. 08-104.

NEGC proposes to increase the monthly customer charge from $9.00 to $9.90 per month for Rate R-1 and Rate R-3 (Exhs. NEGC-JDS-1-13, at 1, 3; NEGC-JDS-1-15, Proposed M.D.P.U. Nos. 1003A, 1005A). The Company proposes to increase the customer charge for Rate R-2 customers from $5.08 to $9.90, and for Rate R-4 customers from $4.28 to $9.90 (Exhs. NEGC-JDS-1-13, at 2, 4; NEGC-JDS-1-15, Proposed M.D.P.U. Nos. 1004A, 1006A).

The proposed R-1 and R-2 delivery charge during the peak season is $0.4174 per therm for the first five therms consumed, and $0.5076 per therm for each additional therm consumed (Exhs. NEGC-JDS-1-13, at 1, 2; NEGC-JDS-1-15, Proposed M.D.P.U. Nos. 1003A, 1004A). The proposed R-1 and R-2 delivery charge during the off-peak period is $0.3984 per therm for the first five therms consumed, and $0.4614 per therm for each additional therm consumed (Exhs. NEGC-JDS-1-13, at 1, 2; NEGC-JDS-1-15, Proposed M.D.P.U. Nos. 1003A, 1004A).

The proposed R-3 and R-4 delivery charge during the peak season is $0.3553 per therm for the first 35 therms consumed, and $0.4254 per therm for each additional therm consumed (Exhs. NEGC-JDS-1-13, at 3, 4; NEGC-JDS-1-15, Proposed M.D.P.U. Nos. 1005A, 1006A).

The proposed R-3 and R-4 delivery charge during the off-peak period is $0.2784 per therm for the first ten therms consumed and $0.3272 per therm for each additional therm consumed (Exhs. NEGC-JDS-1-13, at 3, 4; NEGC-JDS-1-15, Proposed M.D.P.U. Nos. 1005A, 1006A).

b. Analysis and Findings

According to the Company's COSS, the embedded customer charge for Rates R-1 and R-2 is $27.67 and the embedded customer charge for Rates R-3 and R-4 is $28.95 per month (Exh. AG-4-1, Att. (JDS-1)(B)). Based on a review of the embedded costs and the seasonal and annual bill impacts on customers, and our objective of lowering customers' bills through increased end-use efficiency, the Department finds that a Rate R-1 and Rate R-2, designed with a $9.90 monthly customer charge, satisfies continuity goals and produces bill impacts that are moderate and reasonable, considering the size of the rate increase. Based on a review of the embedded costs and bill impacts, and our objective of lowering customers' bills through increased end-use efficiency, the Department finds that a Rate R-3 and Rate R-4, designed with a $9.90 monthly customer charge, satisfies continuity goals and produces bill impacts that are moderate and reasonable, considering the size of the rate increase.

The head and tail block rates shall be calculated to recover the remaining class revenue requirement approved in this filing using the methods approved above. That is: (1) set the head block to recover 25 percent of billed sales in the head block; (2) set the tail block rate for each season at 105 percent of the average variable rates for that season; (3) calculate the head block rate for each season at a level that would recover the remaining target revenues to be collected in that season through the variable energy charge; and (4) use the allocation factor proposed by NEGC to assign the class revenue requirement to the peak and off-peak seasons.[219]

2. Rate G-41/T-41 (C&I Low Annual Use, Low Load Factor)

a. Introduction

Rate G-41 is available to C&I customers purchasing default service, while Rate T-41 is available to C&I customers that are not purchasing default service (Exh. NEGC-JDS-1-15, Proposed M.D.P.U. Nos. 1007A, 1013A). Rate G-41/T-41 is available to C&I customers that have annual usage of between zero therms and 8,000 therms of gas per year and have consumption of gas during the months of May through October that is 30 percent or less of total consumption during the same calendar year as determined by NEGC (Exh. NEGC-JDS-1-15, Proposed M.D.P.U. Nos. 1007A, 1013A). The Company has proposed to increase the customer charge for Rate G-41/T-41 customers from \$20.00 to \$22.00 per month (Exhs. NEGC-JDS-1-13, at 5; NEGC-JDS-1-15, Proposed M.D.P.U. Nos. 1007A, 1013A).

The proposed Rate G-41/T-41 delivery charge during the peak season is \$0.3318 per therm for the first 75 therms consumed and \$0.4082 per therm for each additional therm consumed (Exhs. NEGC-JDS-1-13, at 5; NEGC-JDS-1-15, Proposed M.D.P.U. Nos. 1007A, 1013A). The proposed Rate G-41/T-41 delivery charge during the off-peak period is \$0.2192 per therm for the first 25 therms consumed and \$0.2633 per therm for each additional therm

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219 The calculation of all volumetric delivery charges for each rate class shall be truncated after the fourth decimal place.

consumed (Exhs. NEGC-JDS-1-13, at 5; NEGC-JDS-1-15, Proposed M.D.P.U. Nos. 1007A, 1013A).

b. Analysis and Findings

According to NEGC's COSS, the embedded customer charge for Rate G-41/T-41 is $47.43 per month (Exh. AG-4-1, Att. (JDS-1)(B)). Based on a review of the embedded costs and the seasonal and annual bill impacts on customers, and our objective of lowering customers' bills through increased end-use efficiency, the Department finds that a Rate G-41/T-41, designed with a $22.00 monthly customer charge, satisfies continuity goals and produces bill impacts that are moderate and reasonable, considering the size of the rate increase. The head and tail block rates shall be calculated to recover the remaining class revenue requirement approved in this filing using the methods approved above.

3. Rate G-42/T-42 (C&I Medium Annual Use, Low Load Factor)

a. Introduction

Rate G-42 is available to customers purchasing default service, while Rate T-42 is available to customers that are not purchasing default service (Exh. NEGC-JDS-1-15, Proposed M.D.P.U. Nos. 1008A, 1014A). Rate G-42/T-42 is available to C&I and institutional customers that have annual usage of between 8,001 therms and 100,000 therms of gas per year and have consumption of gas during the months of May through October that is 30 percent or less of total consumption during the same calendar year as determined by the Company (Exh. NEGC-JDS-1-15, Proposed M.D.P.U. Nos. 1008A, 1014A). The Company has proposed to increase the customer charge for Rate G-42/T-42 customers from $30.00 to $33.00 per month (Exh. NEGC-JDS-1-15, Proposed M.D.P.U. Nos. 1008A, 1014A).

The proposed Rate G-42/T-42 delivery charge during the peak season is $0.3196 per therm for the first 850 therms consumed and $0.3940 per therm for each additional therm consumed (Exhs. NEGC-JDS-1-13, at 6; NEGC-JDS-1-15, Proposed M.D.P.U. Nos. 1008A, 1014A). The proposed Rate G-42/T-42 delivery charge during the off-peak period is $0.2142 per therm for the first 300 therms consumed and $0.2627 per therm for each additional therm consumed (Exhs. NEGC-JDS-1-13, at 6; NEGC-JDS-1-15, Proposed M.D.P.U. Nos. 1008A, 1014A).

b. Analysis and Findings

According to the Company's COSS, the embedded customer charge for Rate G-42/T-42 is $383.67 per month (Exh. AG-4-1, Att. (JDS-1)(B)). Based on a review of the embedded costs and the seasonal and annual bill impacts on customers, and our objective of lowering customers' bills through increased end-use efficiency, the Department finds that a Rate G-42/T-42, designed with a $33.00 monthly customer charge, satisfies continuity goals and produces bill impacts that are moderate and reasonable, considering the size of the rate increase. Therefore, the Department directs the Company to set the Rate G-42/T-42 customer charge at $33.00 per month, with volumetric head and tail block rates calculated using the method approved above to collect the remaining class revenue responsibility, maintaining the ratio of peak to off-peak season revenue requirement proposed by the Company.

4. Rate G-43/T-43 (C&I High Annual Use, Low Load Factor)

a. Introduction

Rate G-43 is available to customers purchasing default service, while Rate T-43 is available to customers that are not purchasing default service (Exh. NEGC-JDS-1-15, Proposed M.D.P.U. Nos. 1009A, 1015A). Rate G-43/T-43 is available to C&I and institutional customers that have annual usage of greater than 100,000 therms of gas per year and have consumption of gas during the months of May through October that is 30 percent or less of total consumption during the same calendar year as determined by the Company (Exh. NEGC-JDS-1-15, Proposed M.D.P.U. Nos. 1009A, 1015A). NEGC has proposed to increase the customer charge for Rate G-43/T-43 customers from $700.00 to $770.00 per month (Exhs. NEGC-JDS-1-13, at 7; NEGC-JDS-1-15, Proposed M.D.P.U. Nos. 1009A, 1015A).

The proposed Rate G-43/T-43 delivery charge during the peak season is $0.1860 per therm for the first 8,000 therms consumed and $0.2222 per therm for each additional therm consumed (Exhs. NEGC-JDS-1-13, at 7; NEGC-JDS-1-15, Proposed M.D.P.U. Nos. 1009A, 1015A). The proposed Rate G-43/T-43 delivery charge during the off-peak period is $0.1252 per therm for the first 4,000 therms consumed and $0.1481 per therm for each additional therm consumed (Exh. NEGC-JDS-1-15, Proposed M.D.P.U. Nos. 1009A, 1015A).

b. Analysis and Findings

According to the Company's COSS, the embedded customer charge for Rate G-43/T-43 is $596.23 per month (Exh. AG-4-1, Att. (JDS-1)(B)). Based on a review of the bill impacts on customers, and our objective of lowering customers' bills through increased end-use efficiency, the Department finds that a Rate G-43/T-43, designed with an increase in the monthly customer charge from $700.00 to $770.00, satisfies continuity goals and produces bill impacts that are moderate and reasonable, considering the size of the rate increase. Therefore, the Department directs NEGC to set the Rate G-43/T-43 customer charge at $770.00 per month, with volumetric head and tail block rates calculated using the method approved above to collect the remaining class revenue responsibility, maintaining the ratio of peak to off-peak season revenue requirement proposed by the Company.

5. Rate G-51/T-51 (C&I Low Annual Use, High Load Factor)

a. Introduction

Rate G-51 is available to customers purchasing default service, while Rate T-51 is available to customers that are not purchasing default service (Exh. NEGC-JDS-1-15, Proposed M.D.P.U. Nos. 1010A, 1016A). Rate G-51/T-51 is available to C&I and institutional customers that have annual usage of between zero and 8,000 therms of gas per year and have consumption of gas during the months of May through October that is 30 percent or more of total consumption during the same calendar year as determined by the Company (Exh. NEGC-JDS-1-15, Proposed M.D.P.U. Nos. 1010A, 1016A). NEGC has proposed to increase the customer charge for Rate G-51/T-51 customers from $20.00 to

$22.00 per month (Exhs. NEGC-JDS-1-13, at 8; NEGC-JDS-1-15, Proposed M.D.P.U. Nos. 1010A, 1016A).

The proposed Rate G-51/T-51 delivery charge during the peak season is $0.3125 per therm for the first 80 therms consumed and $0.3850 per therm for each additional therm consumed (Exhs. NEGC-JDS-1-13, at 8; NEGC-JDS-1-15, Proposed M.D.P.U. Nos. 1010A, 1016A). The proposed Rate G-51/T-51 delivery charge during the off-peak period is $0.2227 per therm for the first 60 therms consumed and $0.2750 per therm for each additional therm consumed (Exhs. NEGC-JDS-1-13, at 8; NEGC-JDS-1-15, Proposed M.D.P.U. Nos. 1010A, 1016A).

b. Analysis and Findings

According to NEGC's COSS, the embedded customer charge for Rate G-51/T-51 is $59.51 per month (Exh. AG-4-1, Att. (JDS-1)(B)). Based on a review of the embedded costs, the bill impacts on customers, and our objective of lowering customers' bills through increased end-use efficiency, the Department finds that a Rate G-51/T-51, designed with a $22.00 monthly customer charge, satisfies continuity goals and produces bill impacts that are moderate and reasonable, considering the size of the rate increase. Therefore, the Department directs the Company to set the Rate G-51/T-51 customer charge at $22.00 per month, with volumetric head and tail block rates calculated using the method approved above to collect the remaining class revenue responsibility, maintaining the ratio of peak to off-peak season revenue requirement proposed by the Company.

6. Rate G-52/T-52 (C&I Medium Annual Use, High Load Factor)

a. Introduction

Rate G-52 is available to customers purchasing default service, while Rate T-52 is available to customers that are not purchasing default service (Exh. NEGC-JDS-1-15, Proposed M.D.P.U. Nos. 1011A, 1017A). Rate G-52/T-52 is available to C&I and institutional customers not purchasing default service from NEGC that have annual usage of between 8,001 therms and 100,000 therms of gas per year and have consumption of gas during the months of May through October that is 30 percent or more of total consumption during the same calendar year as determined by the Company (Exh. NEGC-JDS-1-15, Proposed M.D.P.U. Nos. 1011A, 1017A). The Company has proposed to increase the customer charge for Rate G-52/T-52 customers from $30.00 to $33.00 per month (Exhs. NEGC-JDS-1-13, at 9; NEGC-JDS-1-15, Proposed M.D.P.U. Nos. 1011A, 1017A).

The proposed Rate G-52/T-52 delivery charge during the peak season is $0.3316 per therm for the first 550 therms consumed and $0.4023 per therm for each additional therm consumed (Exhs. NEGC-JDS-1-13, at 9; NEGC-JDS-1-15, Proposed M.D.P.U. Nos. 1011A, 1017A). The proposed Rate G-52/T-52 delivery charge during the off-peak period is $0.2325 per therm for the first 350 therms consumed and $0.2873 per therm for each additional therm consumed (Exhs. NEGC-JDS-1-13, at 9; NEGC-JDS-1-15, Proposed M.D.P.U. Nos. 1011A, 1017A).

b. Analysis and Findings

According to NEGC's COSS, the embedded customer charge for Rate G-52/T-52 is $331.45 per month (Exh. AG-4-1, Att. (JDS-1)(B)). Based on a review of the embedded costs and the bill impacts on customers, and our objective of lowering customers' bills through increased end-use efficiency, the Department finds that a Rate G-52/T-52, designed with a $33.00 monthly customer charge, satisfies continuity goals and produces bill impacts that are moderate and reasonable, considering the size of the rate increase. Therefore, the Department directs NEGC to set the Rate G-52/T-52 customer charge at $33.00 per month, with volumetric head and tail block rates calculated using the method approved above to collect the remaining class revenue responsibility, maintaining the ratio of peak to off-peak season revenue requirement proposed by the Company.

7. Rate G-53/T-53 (C&I High Annual Use, High Load Factor)

a. Introduction

Rate G-53 is available to customers purchasing default service, while Rate T-53 is available to customers that are not purchasing default service (Exh. NEGC-JDS-1-15, Proposed M.D.P.U. Nos. 1012A, 1018A). Rate G-53/T-53 is available to C&I and institutional customer that have annual usage of greater than 100,000 therms of gas per year and have consumption of gas during the months of May through October that is 30 percent or more of total consumption during the same calendar year as determined by NEGC (Exh. NEGC-JDS-1-15, Proposed M.D.P.U. Nos. 1012A, 1018A). NEGC has proposed to increase the customer charge for Rate G-53/T-53 customers from $700.00 to $770.00 per month (Exhs. NEGC-JDS-1-13, at 10; NEGC-JDS-1-15, Proposed M.D.P.U. Nos. 1012A, 1018A).

The proposed Rate G-53/T-53 delivery charge during the peak season is $2.7657 per maximum daily contract demand ("MDCD") (Exh. NEGC-JDS-1-15, Proposed M.D.P.U. Nos. 1012A, 1018A). The proposed Rate G-53/T-53 delivery charge during the off-peak period is $1.9755 per MDCD (Exh. NEGC-JDS-1-15, Proposed M.D.P.U. Nos. 1012A, 1018A).

b. Analysis and Findings

According to NEGC's COSS, the embedded customer charge for Rate G-53/T-53 is $665.73 per month (Exh. AG-4-1, Att. (JDS-1)(B)). Based on a review of the bill impacts on customers, and our objective of lowering customers' bills through increased end-use efficiency, the Department finds that a Rate G-53/T-53, designed with an increase in the monthly customer charge from $700.00 to $770.00, satisfies continuity goals and produces bill impacts that are moderate and reasonable, considering the size of the rate increase. Therefore, the Department directs the Company to set the Rate G-53/T-53 customer charge at $770.00 per month and to collect the remaining revenue target through the MDCD charge, keeping the ratio of peak to off-peak season revenue requirement proposed by the company.

VIII. 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	58,905,518	41,030	(365,208)	58,581,340
Depreciation & Amoritzation	3,869,219	(8,203)	(26,685)	3,834,331
Taxes Other Than Income Taxes	1,831,474	0	(38,993)	1,792,481
Income Taxes	1,684,389	(9,521)	(241,015)	1,433,853
Return on Rate Base	4,613,033	(26,075)	(418,945)	4,168,013
Cost of Service Excluding Interest on Customer Deposits	70,903,633	(2,768)	(1,090,847)	69,810,018
Test Year Interest on Customer Deposits	7,389	0	0	7,389
Adjustments	(3,530)	0	0	(3,530)
Adjusted Interest on Customer Deposits	3,859	0	0	3,859
Total Cost of Service	70,907,492	(2,768)	(1,090,847)	69,813,877
OPERATING REVENUES				
Operating Revenues	77,408,935	0	0	77,408,935
Revenue Adjustments	(12,667,744)	0	0	(12,667,744)
Total Operating Revenues	64,741,191	0	0	64,741,191
Total Base Revenue Deficiency	**6,166,301**	**(2,768)**	**(1,090,847)**	**5,072,686**

B. Schedule 2 – Operations and Maintenance Expenses

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Purchased Gas Expense	47,981,286	0	0	47,981,286
Total Adj. to Purchased Gas Expense	(10,549,997)	0	0	(10,549,997)
Total Purchased Gas Expense	37,431,289	0	0	37,431,289
Test Year Expense Per Books	29,064,311	0	0	29,064,311
LESS:				
Test Year Interest on Customer Deposits	7,389	0	0	7,389
Test Year Depreciation Expense	3,747,606	0	0	3,747,606
Test Year Payroll Taxes	643,981	0	0	643,981
Test Year Property Taxes	1,129,926	0	0	1,129,926
Test Year State Sales and Excise Taxes	1,727	0	0	1,727
Subtotal	5,530,629	0	0	5,530,629
Test Year Distribution O&M Expense	23,533,682	0	0	23,533,682
ADJUSTMENTS TO O&M EXPENSE:				
Payroll	310,835	39,568	(39,505)	310,898
Employee Benefits	(478,789)	0	(1,185)	(479,974)
Transportation & Work Equipment Costs	4,070	0	0	4,070
Contract Labor	(74,010)	38,353	(19,075)	(54,732)
Uncollectibles Expense	353,701	(69,445)	0	284,256
Postage	3,569	0	0	3,569
Management Support Cost Allocation	(764,750)	0	(77,243)	(841,993)
Professional Fees	35,440	9,617	(24,298)	20,759
Gas Supply and Forecast	(83,974)	0	0	(83,974)
Residential Conservation Program	(63,099)	(3,081)	0	(66,180)
Union Contract Negotiation	56,117	961	(27,531)	29,547
Insurance Premiums	59,779	0	0	59,779
Self-Insured Deductible Expense	(420,031)	0	0	(420,031)
Rate Case Expense	(42,367)	7,179	(154,889)	(190,077)
Rents and Leases	12,803	5,400	0	18,203
Other Miscellaneous Expenses	(1,141,134)	0	0	(1,141,134)
Appliance Company Allocation	(19,596)	27,321	(4,033)	3,692
Inflation	78,528	0	0	78,528
Total Other O&M Expenses	(2,172,908)	55,873	(347,759)	(2,464,794)
Total Distribution O&M Expense	**21,360,774**	**55,873**	**(347,759)**	**21,068,888**
Uncollectibles on Proposed Rate Increase	113,455	(14,843)	(17,449)	81,163
Total O&M Expense	**58,905,518**	**41,030**	**(365,208)**	**58,581,340**

C. Schedule 3 – Depreciation and Amortization Expenses

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Test Year Depreciation Expense	3,747,606	0	0	3,747,606
Adjustments	136,601	(8,203)	(26,274)	102,124
Less: Depreciation Allocated to Appliance Company	14,988	0	411	15,399
Adjusted Depreciation Expense	3,869,219	(8,203)	(26,685)	3,834,331
Total Depreciation & Amortization Expenses	**3,869,219**	**(8,203)**	**(26,685)**	**3,834,331**

D. Schedule 4 – Rate Base and Return on Rate Base

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Utility Plant in Service	110,991,219	(26,800)	(669,158)	110,295,261
LESS:				
Reserve for Depreciation and Amortlization	48,218,839	0	26,793	48,245,632
Net Utility Plant in Service	62,772,380	(26,800)	(695,951)	62,049,629
ADDITIONS TO PLANT:				
Cash Working Capital	2,235,962	(75,462)	(45,284)	2,115,216
Materials and Supplies	960,739	0	0	960,739
Total Additions to Plant	3,196,701	(75,462)	(45,284)	3,075,955
DEDUCTIONS FROM PLANT:				
Reserve for Deferred Income Tax	(11,898,756)	0	(94,747)	(11,993,503)
Customer Deposits	(401,983)	0	0	(401,983)
Customer Contributions	(2,866,871)	(184,888)	0	(3,051,759)
Total Deductions from Plant	(15,167,610)	(184,888)	(94,747)	(15,447,245)
RATE BASE	50,801,471	(287,150)	(835,982)	49,678,339
COST OF CAPITAL	9.08%	9.08%	8.39%	8.39%
RETURN ON RATE BASE	**4,613,033**	**(26,075)**	**(418,945)**	**4,168,013**

E. Schedule 5 – Cost of Capital

PER COMPANY

	PRINCIPAL	PERCENTAGE	COST	RATE OF RETURN
Long-Term Debt	$1,429,265,000	49.83%	7.50%	3.74%
Preferred Stock	$0	0.00%	0.00%	0.00%
Common Equity	$1,439,300,184	50.17%	10.65%	5.34%
Total Capital	$2,868,565,184	100.00%		9.08%
Weighted Cost of				
Debt				3.74%
Equity				5.34%
Cost of Capital				9.08%

COMPANY ADJUSTMENTS

	PRINCIPAL	PERCENTAGE	COST	RATE OF RETURN
Long-Term Debt	$1,429,265,000	49.83%	7.50%	3.74%
Preferred Stock	$0	0.00%	0.00%	0.00%
Common Equity	$1,439,300,184	50.17%	10.65%	5.34%
Total Capital	$2,868,565,184	100.00%		9.08%
Weighted Cost of				
Debt				3.74%
Equity				5.34%
Cost of Capital				9.08%

PER ORDER

	PRINCIPAL	PERCENTAGE	COST	RATE OF RETURN
Long-Term Debt	$1,429,265,000	49.83%	7.33%	3.65%
Preferred Stock	$0	0.00%	0.00%	0.00%
Common Equity	$1,439,300,184	50.17%	9.45%	4.74%
Total Capital	$2,868,565,184	100.00%		8.39%
Weighted Cost of				
Debt				3.65%
Equity				4.74%
Cost of Capital				8.39%

F. Schedule 6 – Cash Working Capital

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Total Distribution O&M Expense	21,360,774	55,873	(347,759)	21,068,888
PLUS:				
Depreciation	3,869,219	(8,203)	(26,685)	3,834,331
Payroll Taxes	654,953	0	(3,263)	651,690
Property Taxes	1,129,926	0	0	1,129,926
Interest on Customer Deposits	3,859	0	(3,859)	0
Subtotal	5,657,957	(8,203)	(33,807)	5,615,947
Other O&M Expense	27,018,731	47,670	(381,566)	26,684,835
LESS:				
Pension and PBOP	2,621,225	0	0	2,621,225
Uncollectibles	532,411	(69,445)	0	462,966
Plant Depreciation	3,869,374	0	0	3,869,374
TWE Depreciation	121,859	0	0	121,859
Subtotal - O&M Expense (Excluding Uncollectables)	19,873,862	117,115	(381,566)	19,609,411
LESS:				
	3,859			
Payroll Taxes	654,953	0	0	654,953
Property Taxes	1,129,926	0	0	1,129,926
Amount Subject to Cash Working Capital (Excluding Uncollectibles)	18,092,842	117,115	(381,566)	17,824,532
Uncollectables	532,411	(69,445)	0	462,966
Total Cash Working Capital Allowance	**2,235,962**	**(75,462)**	**(45,284)**	**2,115,216**
*Per Company is based on a net figure of 43.82 days (43.82 / 365)	12.005%			
** Per Order is based on a net figure of 43.32 days (43.32 / 365)	11.868%			

G. Schedule 7 – Taxes Other Than Income Taxes

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Test Year Payroll Taxes	643,981	0	0	643,981
Adjustments	10,972	0	(3,263)	7,709
Adjusted Test Year Payroll Taxes	654,953	0	(3,263)	651,690
Test Year Property Taxes	1,129,926	0	0	1,129,926
Adjustments	45,194	0	(35,730)	9,464
Less: Appliance Company Allocation	326	0	0	326
Adjusted Test Year Property Taxes	1,174,794	0	(35,730)	1,139,064
State Sales and Excise Taxes	1,727	0	0	1,727
Total Taxes Other Than Income Taxes	**1,831,474**	**0**	**(38,993)**	**1,792,481**

H. Schedule 8 – Income Taxes

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Rate Base	50,801,471	(287,150)	(835,982)	49,678,339
Return on Rate Base	4,613,033	(26,075)	(418,945)	4,168,013
LESS:				
Interest Expense	1,898,391	(10,730)	(30,513)	1,857,147
Total Deductions	1,898,391	(10,730)	(30,513)	1,857,147
Taxable Income Base	2,714,642	(15,344)	(388,432)	2,310,866
Gross Up Factor	1.6205	1.6205	1.6205	1.6205
Taxable Income	4,399,031	(24,865)	(629,447)	3,744,718
Mass Franchise Tax 6.50%	285,937	(1,616)	(40,914)	243,407
Federal Taxable Income	4,113,094	(23,249)	(588,533)	3,501,311
Federal Income Tax Calculated	1,398,452	(7,905)	(200,101)	1,190,446
Total Income Taxes Calculated	**1,684,389**	**(9,521)**	**(241,015)**	**1,433,853**

I. Schedule 9 - Revenues

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
OPERATING REVENUES PER BOOKS	77,408,935	0	0	77,408,935
Revenue Adjustments				
Unbilled Revenues	(734,520)	0	0	(734,520)
LDAF and GAF Deferrals	4,537,658	0	0	4,537,658
Interruptible Transportation Revenue	(26,690)	0	0	(26,690)
Assonet Gate Station	(366,427)	0	0	(366,427)
RCS per Book	(101,327)	0	0	(101,327)
Base Revenue Adjustments	(870,978)	0	0	(870,978)
Weather and Rate Normalization Adjustment	1,608,656	0	0	1,608,656
LDAC Revenue	(6,416,030)	0	0	(6,416,030)
RAAF Revenue	2,822,320	0	0	2,822,320
Normalized PEF Revenue	2,621,225	0	0	2,621,225
GAR Revenue	(55,160,778)	0	0	(55,160,778)
Normalized GAF Production Cost Revenue	1,987,858	0	0	1,987,858
Normalized Gas Supply Cost Revenue	37,431,289	0	0	37,431,289
Total Revenue Adjustments	(12,667,744)	0	0	(12,667,744)
Adjusted Total Operating Revenues	**64,741,191**	**0**	**0**	**64,741,191**

J. Schedule 10 – Revenue Requirements and Calculation of Revenue Increase by Service

	Total Company per Order	Distribution Service per Order	Gas Service per Order	LDAC Service per Order	Total Company as filed	Distribution Service per Company	Gas Service per Company	LDAC Service per Company
Cost of Gas	$ 37,431,289	$ -	$ 37,431,289	$ -	$ 37,431,289	$ -	$ 37,431,289	$ -
O&M Expense	11,474,028	10,411,422	1,062,606	-	11,533,605	10,465,482	1,068,123	-
A&G Expense	9,676,023	6,310,574	744,224	2,621,225	9,924,382	6,539,831	763,326	2,621,225
Depreciation Expense	3,834,331	3,691,230	143,101	-	3,869,220	3,724,817	144,403	-
Amortization Expense	-	-	-	-	-	-	-	-
Taxes Other Than Income Taxes	1,792,481	1,659,972	132,510	-	1,831,465	1,696,074	135,392	-
Income Taxes	1,433,853	1,405,360	28,493	-	1,684,218	1,650,750	33,468	-
Interest on Customer Deposits	3,859	3,859		-	20,101	20,101	-	-
Amortization of ITC	-	-	-	-	-	-	-	-
Rate Base	49,678,342	48,691,140	987,202	-	50,801,291	49,791,800	1,009,491	-
Rate of Return	8.39%	8.39%	8.39%	8.39%	9.08%	9.08%	9.08%	9.08%
Return on Rate Base	4,168,013	4,085,187	82,826	-	4,612,938	4,521,272	91,665	-
Cost of Service	$ 69,813,877	$ 27,567,605	$ 39,625,048	$ 2,621,225	$ 70,907,218	$ 28,618,327	$ 39,667,666	$ 2,621,225
Revenue Credited to Cost of Service	72,975	72,975			72,975	72,975		
Net Cost of Service	**$ 69,740,902**	**$ 27,494,630**	**$ 39,625,048**	**$ 2,621,225**	**$ 70,834,243**	**$ 28,545,352**	**$ 39,667,666**	**$ 2,621,225**
Operating revenues - per books	77,408,935	19,976,669	50,987,568	6,444,697	77,408,935	19,976,669	50,987,568	6,444,697
Revenues Transferred to Cost of Service		2,822,320		(2,822,320)		2,822,320		(2,822,320)
Revenue Adjustments	(12,667,744)	(98,164)	(11,568,421)	(1,001,153)	(12,667,738)	(98,164)	(11,568,421)	(1,001,153)
Total Operating Revenues	64,741,191	22,700,825	39,419,147	2,621,225	64,741,197	22,700,825	39,419,147	2,621,225
Revenue Deficiency	**5,072,686**	**4,868,234**	**204,452**	**-**	**6,166,021**	**5,917,502**	**248,519**	**-**

Note: Schedule 10 is for illustrative purposes only.

IX. ORDER

Accordingly, after due notice, hearing, and consideration, it is

ORDERED: That the tariffs M.D.P.U. No. 1002B and No. 1003A through No. 1024A filed by New England Gas Company on September 16, 2010, to become effective April 1, 2011, are DISALLOWED; and it is

FURTHER ORDERED: That New England Gas Company shall file new schedules of rates and charges designed to increase annual gas base rate revenues by $5,072,686; and it is

FURTHER ORDERED: That New England 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 New England Gas Company shall comply with all other directives contained in this Order; and it is

FURTHER ORDERED: That the new rates shall apply to gas consumed on or after April 1, 2011, 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/
Ann G. Berwick, Chair

/s/
Jolette A. Westbrook, 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.