UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 8-K

CURRENT REPORT
Pursuant to Section 13 or 15(d)
of the Securities Exchange Act of 1934

Date of Report (Date of earliest event reported): February 28, 2018

UNITIL CORPORATION
(Exact name of registrant as specified in its charter)

New Hampshire	**1-8858**	**02-0381573**
(State or other jurisdiction of incorporation)	**(Commission File Number)**	**(IRS Employer Identification No.)**

6 Liberty Lane West, Hampton, New Hampshire	**03842-1720**
(Address of principal executive offices)	**(Zip Code)**

Registrant's telephone number, including area code: (603) 772-0775

N/A
(Former name or former address, if changed since last report)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Indicate by check mark whether the registrant is an emerging growth company as defined in Rule 405 of the Securities Act of 1933 (§230.405 of this chapter) or Rule 12b-2 of the Securities Exchange Act of 1934 (§240.12b-2 of this chapter).

Emerging growth company ☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Item 7.01 Regulation FD Disclosure

The final Order of the Maine Public Utilities Commission ("MPUC"), to which Item 8.01 below refers, is attached as Exhibit 99.1 to this Current Report on Form 8-K.

Item 8.01 Other Events

On February 28, 2018 the MPUC issued its final Order (the "Order") in Docket No. 2017-00065, the distribution base rate case filed in May 2017 by the Maine division of Northern Utilities, Inc. (the "Company"), Unitil Corporation's natural gas utility subsidiary operating in Maine and New Hampshire. The Order would have resulted in a revenue increase of $2,072,647, prior to incorporating the effect of a lower federal income tax rate under the Tax Cuts and Jobs Act of 2017. Incorporating the effect of the lower tax rate resulted in a revenue decrease of $87,243. The Order also provides for a reduction in annual depreciation expense reducing the Company's annual operating costs by approximately $500,000. The Order addresses a number of other issues including a change to therm billing, increases in other delivery charges, and cost recovery under the Company's Targeted Area Buildout program in Saco, Maine ("Saco TAB") and Targeted Infrastructure Replacement Adjustment ("TIRA") program. The new rates and other changes are effective as of March 1, 2018.

The distribution base rate case is based on the Company's operating costs and investments in utility plant for a test year ended December 31, 2016 as adjusted for known and measurable changes. The MPUC approved a return on equity of 9.5 percent and a capital structure reflecting 50 percent equity and 50 percent long-term debt. Additionally, the MPUC approved the inclusion of Saco TAB investments in rate base along with a cost recovery incentive mechanism. The MPUC also approved adjustments to and an extension of the Company's TIRA for an additional eight-year period to provide for annual revenue increases associated with specified targeted operational and safety-related infrastructure replacement and upgrade projects.

Item 9.01 Financial Statements and Exhibits

(d) Exhibits

Number	Exhibit
99.1	Maine Public Utilities Commission Order dated February 28, 2018

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

UNITIL CORPORATION

By: /s/ Mark H. Collin
Mark H. Collin
Senior Vice President, Chief Financial Officer and Treasurer

Date: March 6, 2018

REDACTED

STATE OF MAINE
PUBLIC UTILITIES COMMISSION

Docket No. 2017-00065

February 28, 2018

NORTHERN UTILITIES, INC. d/b/a UNITIL
Request for Approval of Rate Change
Pursuant to Section 307

ORDER
(Corrected)[1]

VANNOY, Chairman; WILLIAMSON and DAVIS, Commissioners

I. SUMMARY

In this Order, the Commission rejects as unjust and unreasonable the proposed increase by Northern Utilities Inc. d/b/a Unitil (Northern or the Company) in its delivery rates of $3,481,567, as initially proposed by Northern on May 31, 2017 and as finally amended in the Company's January 16, 2018 filing which incorporated the effect of the recently enacted Tax Cuts and Jobs Act of 2017 (TCJA). The Company's January 16, 2018 filing was a modification to both its May 31, 2017 proposed increase and its January 8, 2018 Revised Rebuttal Testimony proposed increase. In its place, the Commission orders the Company to decrease its delivery rates by $87,243 as of March 1, 2018. The Commission's decision is based on a cost of equity of 9.50% and reflects the decrease to the Company's allowed tax expense as a result of the recently enacted TCJA. The computations supporting this decision are attached hereto and marked Exhibits 1 through 5.

II. PROCEDURAL HISTORY

On May 31, 2017, pursuant to 35-A M.R.S. §§ 307 and 312 and Chapters 110 and 120 of the Commission's Rules, Northern filed a request to increase its natural gas distribution base rates. In its initial filing, Northern requested that the Commission approve an annual increase of $5,981,413 in distribution revenues based upon a test year ending December 31, 2016, an overall return on rate base of 8.30 percent, and known and measurable adjustments to test year revenues, expenses and rate base. The requested increase would result in a 7.1 percent increase over the Company's test year operating revenues.

Additionally, Northern requested that the Commission extend the Company's Targeted Infrastructure Replacement Adjustment mechanism (TIRA) for an additional four years. The TIRA is a capital cost recovery mechanism designed to recover the costs of certain targeted improvements and upgrades to the Company's distribution system, including the Company's Cast Iron Replacement Program (CIRP) and other operational and safety-related system improvements. The Company also proposed that costs related to excess flow valves (EFVs) be included within the TIRA. The first annual adjustment under the TIRA extension was proposed for May 1, 2018, to recover the Company's 2017 cost of these programs.

1 This Corrected Order corrects editorial and typographical errors on pages 4 and 15 of the original Order. The corrections are noted in bold.

Northern's initial filing consisted of the testimony of: David Chong, Director of Finance and Treasurer for Unitil Service Corp. (description of base rate request, overall revenue requirements, pro forma adjustments from the test year and TIRA); Christopher Leblanc and Kevin Sprague, Vice President of Gas Operations and Director of Engineering, respectively, for Unitil Service Corp. (description of issues related to TIRA and other capital investment issues, including the inclusion of EFVs); Elizabeth Shaw, Director of Human Resources for Unitil Service Corp. (description of salary and wage policies and employee retiree benefit plans included in the Company's cost of service, including pro forma adjustments); Keith Hanson, Senior Accountant for Unitil Service Corp. (lead-lag study and cash working capital requirements); Paul Normand and Debbie Gajewski of Management Applications Consulting (MAC) (depreciation study, accounting and marginal cost of service studies, revenue adjustments, transition from ccf to therm billing, and rate design); and Robert Hevert of Scott Madden, Inc. (cost of capital and return on equity analysis).

A Notice of Proceeding, which provided interested persons with an opportunity to intervene in this matter was issued on June 5, 2017. The Office of the Public Advocate (OPA) filed a petition to intervene, which was granted without objection at an initial case conference held on June 15, 2017. On June 20, 2017, the Hearing Examiner issued a procedural order extending the time period in which Northern customers could file a petition to intervene, due to a prior notice not being received by customers until after the deadline for filing for intervention had passed. Northern was directed to send out a revised customer notice with the intervention date extended until July 14, 2017. No further requests for intervention were received.

Technical conferences on the Company's Direct Testimony were held on July 19, 2017, August 2, 2017, and August 3, 2017. On August 18, 2017, Northern filed Supplemental Testimony concerning the Saco Targeted Area Buildout (Saco TAB). In its Supplemental Testimony, Northern stated that although its Saco TAB plant was recorded as construction work in progress at the end of the test year, it was operationally in service as of December 31, 2017, and therefore should be recovered in this rate proceeding. The proposed revenue requirement associated with the Saco TAB was $677,008.

The OPA submitted the Direct Testimony of Lafayette Morgan and Jerome Mierzwa in response to the Company's case on August 31, 2017. A technical conference on both the OPA's Direct Testimony and Northern's Supplemental Testimony was held on September 19, 2017.

On October 6, 2017, Staff filed its Bench Analysis, along with a Bench Report from the Staff's consultant, William Dunkel (Mr. Dunkel). A technical conference on the Staff's Bench Analysis and Bench Report was held on October 25, 2017, and a public witness hearing was held on October 12, 2017, in Portland, Maine. No member of the public testified at the hearing.[2]

2 A comment was received from a member of the public who was unable to appear at the public witness hearing.

Northern and the OPA submitted Rebuttal Testimony on November 13, 2017. Northern's Rebuttal Testimony included updates to its revenue requirement to reflect known and measurable changes. A technical conference on Northern's Rebuttal Testimony was held on November 29, 2017.

On December 5, 2017, Staff filed the Reply Bench Report of Mr. Dunkel in response to the Company's Rebuttal Testimony on depreciation issues. A technical conference on Mr. Dunkel's Reply Bench Report was held on December 8, 2017. A pre-hearing conference was held on December 11, 2017. Hearings on the prefiled testimony of the OPA and Northern, along with the Staff's Bench Analysis, were held on December 13, 2017 and December 14, 2017.

The Company subsequently updated its revenue requirement again on January 8, 2018, to reflect the Company's most recent actual and projected rate case expense and a post-hearing known and measurable change to insurance expense. In its January 8, 2018 filing, Northern's proposed revenue requirement increase was $6,547,173. The Company and the OPA filed briefs and reply briefs in support of their respective positions on January 12, 2018 and January 19, 2018.

On December 22, 2017, the President signed the TCJA, which reduces the federal corporate tax rate from 35% to 21% effective January 1, 2018. On January 3, 2018, the Hearing Examiner issued a Procedural Order directing Northern to file a statement which calculates the amount of excess deferred income taxes (EDIT) which result from the tax rate change and how the Company plans to flow such EDIT back to ratepayers. The Hearing Examiner also proposed to take administrative notice of this federal legislation and to incorporate the change into the calculations of the gross-up required to provide the Company its allowed Return on Equity (ROE) and in all other instances where the pre-tax weighted average cost of capital (WACC) is utilized on a going forward basis. No party objected to this proposal.

On January 16, 2018, Northern made its filing updating schedules to reflect the effect of the TCJA to the Company's proposed revenue requirement. Northern's revised proposed revenue requirement is $3,481,567. The filing also indicated that on or before January 26, 2018, the Company would file its proposed excess Accumulated Deferred Income Tax (ADIT) Regulatory Liability amortization amount. A conference of counsel to discuss the processing of the impacts of the recently enacted tax change was held on January 18, 2018.

On January 26, 2018, Northern submitted its filing of the impact of the TCJA on the Company's deferred taxes. In addition, on that date, the Company filed Supplemental Testimony of Robert Hevert regarding the impact of the TCJA on the utility industry generally and on the Company's cost of capital in this case. On January 29, 2018, the Company submitted attachments to Mr. Hevert's Supplemental Testimony. The Company requested that Mr. Hevert's Supplemental Testimony and attachments be included in the record in this case.

A technical conference on the Company's TCJA filing was held on January 30, 2018. The Hearing Examiner denied the Company's request to include Mr. Hevert's Supplemental Testimony and attachments in the record on February 1, 2018. Northern filed a Motion for Reconsideration and Rehearing of the Examiner's Ruling on February 7, 2018. The OPA filed a Response In Opposition to Northern's Motion on February 13, 2018. On this same date, the Commission is issuing a decision which denies Northern's Motion and upholds the Examiner's Ruling of February 1, 2018.

On February 7, 2018, the Hearing Examiners in the case issued their Examiners' Report which contained the recommendations of the Commission Staff. On February 14, 2018, the Company filed exceptions to the Examiners' Report and the OPA filed comments on the Report.

III. TAX CUTS AND JOBS ACT OF 2017

In its January 16, 2018 filing updating the rate schedules to incorporate the effect of the TCJA, Northern stated that the tax change resulted in a proposed reduction of $2,876,762 from its updated revenue requirement (including the reduction to the Saco TAB revenue requirement) and yielded a proposed revenue requirement increase of $3,481,567.[3] The methodology used by Northern to calculate the effect employs a formula specified in Federal Energy Regulatory Commission (FERC) Order 475 (June 26, 1987), published when tax rates last changed. As proposed by Northern, this FERC methodology calculates the reduction in income tax expense resulting from the lower tax rate. The calculation begins with the pro forma income taxes in the cost of service after the full amount of rate relief calculated at the tax rate in effect during the test year, and prorates that tax amount by the new rate divided by the old rate. Tr. at 6 (Jan. 18, 2018). The result is the tax expense at the new lower rate. The overall revenue requirement is the revenue deficiency determined in this rate case, less the calculated reduction in income tax expense. The Commission accepts this proposed methodology for determining the effect on revenue requirements of the change in the tax rate.

Northern's calculations reflect its positions on the issues to be determined in this case and incorporate the reduction in the federal corporate tax rate. The Commission's determinations in this case would have resulted in an overall increase of **$2,072,647,** prior to incorporating the effect of the reduced tax rate. Incorporating the effect of the tax rate reduction using the Company's proposed methodology as set forth in its January 16, 2018 filing results in a revenue decrease of **$87,243.**

3 The revised revenue requirement also incorporates an update to rate case expenses and changes to the WACC resulting from an update to the cost of long-term debt.

As noted in its January 16, 2018 filing, the tax rate reduction also requires the Company to revalue downward the net ADIT liabilities on its balance sheet. In accordance with Generally Accepted Accounting Principles (GAAP), the resulting excess ADIT will be recognized on the Company's books as a Regulatory Liability. Northern proposes to use the Average Rate Assumption Method (ARAM) to pass back to ratepayers the EDIT. In its January 26, 2018 filing, Northern provided the calculation of its proposed EDIT amortization amount in accordance with ARAM. Northern noted that because its book depreciation does not exceed tax depreciation until 2020, and the amortization of EDIT will not begin until then, no change in rates is required at this time. The Commission accepts Northern's calculations and statement that no change in rates is necessary, and directs that Northern not begin amortizing the regulatory liability created for the EDIT on its books until such time as its book depreciation exceeds its tax depreciation.

Lastly, in its January 16, 2018 filing, Northern urged the Commission to weigh any potential credit implications and an increase in the Company's cost of capital associated with reduced cash flow resulting from the tax rate change. As noted in the February 1, 2018 Examiner's Ruling in this case, such impacts are not clearly defined or quantified at this point and the Commission makes no adjustment to cost of capital, cost of equity or revenue requirements on this basis. This does not preclude the Company from requesting that the Commission open an investigation into the impact of the TCJA on its ROE and the resulting impact on its rates pursuant to the provisions of 35-A M.R.S. § 1302.

IV. COST OF CAPITAL

A. Positions of the Parties

1. Northern

In its Brief, Northern argues that the Commission should adopt a 10.30% ROE as recommended by its witness, Mr. Hevert, and a capital structure that consists of 51.70% common equity and 48.30% long-term debt. Although in its initial filing Northern had proposed a 6.16% cost of long-term debt, in its Brief, the Company agrees that the cost of long-term debt used in this case should be modified to reflect new debt issuances in November 2017 and a sinking fund payment on its existing 6.95% debt in December 2017, thereby reducing the cost of long-term debt to 5.55%. Northern Brief at 42. Combining the updated weighted average cost of long-term debt with Northern's recommended capital structure and an ROE of 10.30%, results in an after-tax WACC of 8.01%.

Northern states that it does not find the recommendation in Staff's Bench Analysis of a hypothetical 50% common equity layer to be unreasonable. *Id.* at 39. Nevertheless, Northern continues to support its proposed capital structure and argues that its test year-end capital structure, which includes 51.7% common equity and 48.3% long-term debt, is reasonable, consistent with industry averages and the Company's financing goals and objectives, and supports the financial profile required to ensure access to capital markets. *Id.* at 38. Additionally, Northern argues that its proposed capital structure is consistent with the Company's proforma year-end 2017 capital structure of 51% common equity and 49% long-term debt, reflecting the issuance of $50 million in long-term debt in November 2017, the retirement of $10 million in long-term debt in December 2017, the issuance by Unitil Corporation of a $30 million equity offering late in 2017 and its commitment to make a $32 million equity contribution to Northern. *Id.* at 39. Northern objects to the inclusion of any short-term debt in the capital structure, arguing that including a short-term debt component for ratemaking purposes is not matched to or consistent with the long-term nature of utility assets. *Id.* at 40.

In his initial testimony, Northern's cost of capital expert, Mr. Hevert, develops a cost of equity in the range of 10.00% to 10.60% and recommends an ROE of 10.30%. In developing his recommendation, Mr. Hevert first identifies a peer group of utilities and then employs several methodologies to estimate Northern's ROE, including the Discounted Cash Flow (DCF) model (using a Constant Growth and Multi-Stage form), the Capital Asset Pricing Model (CAPM) and the Bond Yield Plus Risk Premium approach. Mr. Hevert's DCF results range from 7.47% to 11.81% with a mid-point of 9.64%. Hevert Dir. Test. at 56. Additionally, although he did not recommend a specific adjustment to the ROE, Mr. Hevert calculated a flotation cost adjustment of 11 basis points, stating that the effect of flotation costs, in addition to the Company's other business risks, should be considered in determining where Northern's ROE falls within the range of analytical results. Hevert Dir. Test. at 35-38.

In his Rebuttal Testimony, Mr. Hevert provided an update to his analysis and also included an updated DCF analysis based on Staff's methodology but with a revised proxy group and updated market information as of September 29, 2017. Hevert Reb. Test. at 11. This updated analysis produces a DCF range of 8.70% to 9.46% with a mid-point of 9.22%. In addition, Mr. Hevert provided an updated CAPM analysis, using both current 30-year Treasury rates and projected long-term Treasury rates as the risk-free rate. Mr. Hevert's CAPM analysis produced a range of 9.77% to 11.64% using the then current Treasury rate of 2.77% and 10.30% to 12.17% using the projected Treasury rate of 3.30%. Combining the Company's recommended capital structure with the adjusted cost of long-term debt and an ROE of 10.30% produces an after-tax WACC of 8.01%. Northern Brief at 37.

2. <u>Office of the Public Advocate</u>

The OPA states that the Commission should adopt a 9.15% cost of equity for Northern as recommended by the OPA's witness in his direct testimony. OPA Brief at 20. In his testimony, Mr. Morgan did not present a cost of equity analysis but, rather, bases his recommendation on the DCF results presented by the Company's witness. To derive his recommendation, Mr. Morgan used only the average mean growth rate results from Mr. Hevert's three DCF approaches. This produces an indicated ROE with a range from 8.61% to 9.69% and an average of 9.15%. Morgan Dir. Test. at 21-22.

The OPA also recommends that the cost of Northern's long-term debt be adjusted to reflect the known and measurable change associated with the retirement of $10 million in 6.96% debt in December 2017 and the issuance of $50 million in new long-term debt in November 2017. This adjustment would reduce the cost of long-term debt to 5.56%.[4] OPA Brief at 19.

The OPA agrees with the capital structure proposed by Staff in its Bench Analysis, which consists of a hypothetical equity component of 50%, long-term debt equal to 49.18% and short-term debt of 0.82%. The OPA argues that this proposed capital structure is close to the structure proposed by the Company and is in-line with the hypothetical equity component the Commission approved for another Maine gas utility that is a subsidiary of a larger company. Additionally, the OPA notes that although Northern has not incorporated this proposed equity layer, the Company does acknowledge that 50% common equity reflects a reasonable capital structure that is in line with its actual equity, its long-term financing activities and targets, and with the average equity ratio of its peer group. OPA Brief at 22, citing Chong Reb. Test. at 22-23.

Combining the OPA's updated weighted average cost of long-term debt with the OPA's recommended capital structure and an ROE of 9.15% results in an after-tax WACC of 6.93%.

3. Bench Analysis

In its Bench Analysis, the Staff recommended an ROE of 9.50%; the use of a hypothetical capital structure which includes a common equity layer of 50% and a component of short-term debt; and adjustments to the cost of long-term debt to reflect the retirement of $10 million in 6.95% debt in December 2017 and the issuance of $50 million in new long-term debt at a weighted average cost of 4.00% in November 2017. These changes result in an after-tax WACC of 7.50%.

In arriving at its ROE recommendation, the Staff developed a proxy group of gas and electric utilities that consisted of 14 companies and used a DCF analysis, both a constant-growth model and a two-stage growth model, and a CAPM calculation as a check on the DCF results. Staff developed a DCF range of 8.24% to 9.54% and a CAPM range of 9.29% to 11.10%. Staff's analysis included two companies in the proxy group which were included in error. ODR-006-002. As noted above, Mr. Hevert's Rebuttal Testimony included an updated DCF analysis based on Staff's methodology, which produces a DCF range of 8.70% to 9.46% with a mid-point of 9.22%.

Staff additionally recommended the use of a hypothetical capital structure with a common equity layer of 50% and the inclusion of a component of short-term debt at a cost equal to Northern's most recent cost of short-term borrowings, resulting in a capital structure that includes 49.18% of long-term debt and 0.82% of short-term debt. Staff derived the short-term debt component based on the calculation of cash working capital

4 Northern calculates the adjusted cost of long-term debt to be 5.55%. ODR-003-032.

needs set forth in the lead-lag study filed by the Company. With respect to the cost of the long-term debt component of Northern's capital structure, Staff recommended that the cost of long-term debt should be reduced from 6.16% as filed by Northern to 5.55%. This reduction in the cost of long-term debt reflects the impact on the weighted average cost of debt of two known and measurable changes to the Company's outstanding debt discussed above that are effective prior to the rate effective date. ODR-003-002.

B. The Hope-Bluefield Standard

Two United States Supreme Court decisions of more than 70 years ago, known as the *Bluefield* and *Hope* cases, provide the standards for measuring the reasonableness of a utility's allowed ROE. Taken together, the *Hope-Bluefield* decisions establish that:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made…on investments in other business undertakings which are attended by corresponding risks and uncertainties…The return should be reasonably sufficient to assure confidence in the financial soundness of the utility, and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties

Bluefield Water Works and Improvement Co. v. Public Service Commission of West Virginia, 262 U.S. 679 (1923).

Additionally, the idea of associating the allowed return to a common equity owner with those available from other companies of comparable risk was established in the *Hope* decision:

> [T]he return to the equity owner should be commensurate with the return on investment in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.

Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 591 (1944).

Thus, the practice of determining an appropriate ROE for a company that is not publicly traded such as Northern is one that involves developing a comparable group of companies, for which market-based information is available, that are in the same business and that present similar financial risks. The *Hope-Bluefield* standard has long served as the benchmark against which this Commission measures an appropriate ROE.

C. Discussion and Decision

As noted, both the Company and the OPA agree with the recommendation in the Staff's Bench Analysis that the cost of the long-term debt component of the capital structure should be updated to reflect the impact of the December 2017 sinking fund payment and the November 2017 issuance of $50 million in new long-term debt. OPA Brief at 19; Northern Brief at 42. Northern has calculated that including these adjustments would reduce the weighted average cost of debt from 6.16% to 5.55%. ODR-003-032. The Commission finds that reducing the cost of long-term debt for these known and measurable changes is reasonable. With this agreement and Commission finding, there remain two crucial factors associated with the cost of capital that must be determined; the capital structure and the allowed return on equity. Additionally, the enactment of the Tax Cuts and Jobs Act of 2017 has implications on the pre-tax WACC that is required for calculations associated with the TIRA recovery mechanism and the Saco TAB as discussed below.

1. Capital Structure

As noted, Northern urges the Commission to adopt a capital structure based on its actual year-end 2016 balances which consists of 51.70% common equity and 48.30% long-term debt. The OPA and Commission Staff recommend a hypothetical capital structure which consists of 50% common equity, 0.82% of short-term debt and 49.18% of long-term debt. Notwithstanding its recommended capital structure, Northern has acknowledged that a capital structure with a 50% common equity layer is reasonable. Although he took exception to the inclusion of a short-term debt component, Mr. Chong testified, "Staff's proposed capital structure closely matches the actual current capital structure of the Company, reflects the Company's targeted long-term equity ratio at current market and regulatory conditions, and is reasonably representative of the Company's long-term financing activities." Chong Reb. Test. at 22-23.

The Commission finds that the use of a hypothetical capital structure consisting of 50% common equity and 50% debt is reasonable for ratemaking purposes. As noted by the OPA, the use of a hypothetical capital structure is consistent with the capital structure approved for another Maine gas utility that is a subsidiary of a larger company. OPA Brief at 22. Additionally, a 50% common equity layer is consistent with the common equity ratio of the proxy group used in the ROE analysis. Hevert Reb. Test. at 15. The use of a hypothetical 50/50 capital structure relieves any concern that the structure is based on a specific point in time and, thus, susceptible to wide variability over time. We decline to include a component of short-term debt in the Company's capital structure as recommended in the Staff's Bench Analysis.

2. Return on Equity

As an initial matter, although there are differences between the proxy group used by the Company and the proxy group used in the Commission Staff analysis, there is substantial overlap of the proxy groups. The Staff and the Company each used a proxy group of 12 companies and nine are common to both. This sample size is large enough and consistent enough to allow a meaningful analysis of market returns.

As noted, two companies in Staff's proxy group presented in the Bench Analysis were included in error. Staff did not file a reply bench analysis in this case, which would have afforded an opportunity to update the ROE analysis both to reflect more current market information and to adjust its proxy group. As noted above, in his Rebuttal Testimony, Mr. Hevert provided an updated analysis based on Staff's methodology and with market data from September 29, 2017, but with a revised Staff proxy group that removed the two companies included in error. Hevert Reb. Testimony at 11. In addition, Mr. Hevert removed one company from Staff's proxy group because its growth rate and DCF results were so low as to be unreasonable. *Id.* at 10. Although the Commission does not necessarily agree with all the adjustments made by Mr. Hevert to Staff's proxy group, the proxy group is substantially the same as that recommended by Staff and the methodology used by Mr. Hevert is identical. Thus, the updated Staff DCF analysis presented by Mr. Hevert in his Rebuttal Testimony is reasonably representative of a corrected and updated analysis had one been done by Staff. *Id.* at 12. This updated DCF analysis produces the indicated ROE range as shown in Figure IV.1 below.

Figure IV.1

Updated Staff DCF Analysis

	Low	High	Mean
Staff Revised Proxy Group			
Constant Growth DCF Model	8.98%	9.46%	9.22%
Two-Step DCF Model	8.70%	8.86%	8.78%

In his rebuttal testimony, Mr. Hevert also updated his DCF analysis to reflect current market data as shown in Figure IV.2 below.[5] *Id.* at 16.

5 The Commission notes that the upper end of the ROE range produced by Mr. Hevert's Constant Growth DCF analysis is more than 100 basis points higher than the upper end of the ranges produced by the other DCF-based analyses in the record and is the only one above 11%. It appears that this high-end number results in large part from the effect of one particular proxy group member used in Mr. Hevert's analysis with a high estimated growth rate. Specifically, Mr. Hevert used an earnings growth rate of 15.84% for Chesapeake Utilities Corporation, significantly higher than the earnings growth rate used for most of the remainder of the proxy group. In all variations of the Constant Growth DCF analysis provided by Mr. Hevert, the results for Chesapeake Utilities set the upper end of the ROE range. Hevert Reb. Exhibit RBH-1.

Figure IV.2

Hevert Rebuttal DCF Results

	Low	High	Mean
Hevert Rebuttal DCF			
Constant Growth DCF	7.19%	11.26%	9.23%
Multi-Stage DCF	7.52%	10.24%	8.88%

Consistent with our practice, the Commission relies primarily on a discounted cash flow analytical structure to determine an appropriate ROE and uses CAPM results as a check on the DCF results. *See, e.g. Investigation of Central Maine Power Company, Company's Revenue Requirements and Rate Design (Phase II)*, Docket No. 1997-00580, Order, (January 19, 2000) (97-580) and *Emera Maine, Request for Approval of a Proposed Rate Increase*, Docket No. 2015-00360, Order—Part II (Dec. 22, 2016). The Commission's reliance on the DCF market-oriented approach to determine the common-equity cost for the Company is consistent with the *Hope- Bluefield* standard in that it incorporates the equity returns that investors currently expect to receive from investing in companies with risks similar to Northern. The indicated ROE supported by the DCF evidence ranges from a low of 7.19% to a high of 11.26% with a mid-point of 9.23%.

The Company and the Staff also provided the results of CAPM analyses which we use as a check to the DCF results. The results of Staff's CAPM analysis indicate an ROE range of 9.29% to 11.10%. Bench Analysis at 16. In his rebuttal testimony, Mr. Hevert updated his CAPM results to reflect adjustments to his proxy group and more recent market information. Consistent with the Commission's preference as indicated in 97-580, we consider the CAPM results that are based on current Treasury rates rather than a forecast of interest rates. Mr. Hevert's CAPM results based on current Treasury rates indicate an ROE range of 9.77% to 11.64%. Hevert Reb. Test. at 26.

As noted, the Commission's practice is to rely primarily on the DCF methodology results and to use the CAPM results as a check on the reasonableness of the DCF results. The DCF analyses produce an indicated range of ROEs from 7.19% to 11.26% with a mid-point of 9.23%. Although the low-end of the CAPM results overlap with the high end of the DCF results, generally, the CAPM results suggest a higher ROE range and indicate that it may be appropriate to adjust Northern's awarded ROE to a level that is above the mid-point of the DCF results.

The Commission is cognizant of current equity market conditions and the characteristics of different analytical tools used to estimate a company's cost of equity in a rate making proceeding and continues to have confidence in the DCF methodology. In addition, the evidence in the record in this case does not demonstrate that Northern's risk profile differs in any marked way from the risk profile of the proxy group upon which these results were determined. Nevertheless, the CAPM results and the inclusion of a floatation cost adjustment as presented in Mr. Hevert's Testimony support the conclusion that an ROE of 9.50%, somewhat above the mid-point of the DCF range, is an appropriate equity return for Northern.

3. Tax Cuts and Jobs Act, ROE and WACC

The objective of cost of equity analysis is to arrive at a determination of a market- based cost of capital which represents the return equity investors could expect from other investments of similar risk. Thus, the return on equity estimates are generally seen as after-tax returns. To translate an after-tax equity return to a pre-tax revenue requirement generally requires a gross-up of the allowed ROE to reflect statutory corporate income tax rates.

As noted, the TCJA reduced the statutory federal income tax rate from 35% to 21%. This reduction in the tax rate affects the calculation of pre-tax WACC as well as other components of cost of service rate making. Northern's revenue requirements model (Exhibit DLC-2) uses an after-tax ROE and WACC to calculate the return on rate base and then applies a tax gross-up to the entire calculated revenue deficiency. Consequently, with the determinations of capital structure and ROE as described above, for purposes of determining the Company's revenue requirement, the WACC shall be 7.53% as shown in Figure IV.3 below.

Figure IV.3

Capital Structure	Ratios	Rate	Cost
Long-Term Debt	50.00%	5.55%	2.78%
Short-Term Debt	0.00%	2.19%	0.00%
Preferred Stock	0.00%	0.00%	0.00%
Common Stock	50.00%	9.50%	4.75%
	100.00%		7.53%

For calculations associated with the Saco TAB and the annual TIRA rate adjustments, however, a pre-tax ROE and WACC are required. The tax gross-up of the ROE and resulting WACC uses the new effective tax rate of 28.05% as provided by the Company in ARAM Attachment 1, Page 2 of 2. Thus, for Saco TAB and TIRA calculations, the pre-tax WACC will be 9.38% as shown in Figure IV.4.

Figure IV.4

Pre-Tax Weighted Average Cost of Capital

Capital Structure	Ratios	Rate	Cost	Pre-Tax WACC Tax Gross up Eff Tax rate 28.05%
Long-Term Debt	50.00%	5.55%	2.78%	2.78%
Short-Term Debt	0.00%	2.19%	0.00%	0.00%
Preferred Stock	0.00%	0.00%	0.00%	0.00%
Common Stock	50.00%	9.50%	4.75%	6.60%
	100.00%		7.53%	
Pre-Tax Weighted Average Cost of Capital				**9.38%**

V. REVENUE REQUIREMENTS

A. Year-end Rate Base

1. Positions of the Parties

As part of the initial filing in this case, the Company calculated its revenue requirement using a year-end rate base. The Staff and the OPA responded to the Company's proposal by both taking the position that the Company's proposal resulted in a mismatch of costs and revenue. The mismatch results because under the Company's proposal all investments in utility plant made through the end of the test year would be closed to rate base at the end of the year and thus would be fully recovered from ratepayers. On the other hand, the revenue associated with such plant which would not begin being collected until after year end, would not be included since the Company considers such revenues to be out of the test year.

The Company argues that a year-end rate base is appropriate because it better aligns expenses, revenues and rate base with the period in which rates are going into effect and thus reduces earnings attrition. The Company notes that it is subject to earnings attrition because of its high construction costs and cites to the testimony of David Chong which shows that the Company has not earned the return allowed in its last rate case. Northern Brief at 7.

To address the Company's use of the end of test year rate base the OPA proposed to adjust test year revenues to reflect an entire year's worth of revenue associated with customer growth during the test year. The OPA adjustment developed by Mr. Mierzwa was based on the difference between the number of customers at the end of the test year and the average number of test-year customers multiplied by the average revenue per customer by customer class. Mr. Mierzwa then accounted for the lost sales from the G-42 customer that was lost during 2017 which was proposed by the Company. Mierzwa Dir. Test. at 17.

In the Bench Analysis, the Staff noted that in its view, year-end rate base most appropriately matches 2017 revenues, not test year revenues. Therefore, 2017 actual revenues should be used as a known and measurable change in calculating the Company's revenue deficiency in this case. The Staff requested that the Company update its case with actual 2017 weather normalized sales data as the case progressed. The Staff noted that it would not be necessary to update 2016 sales with the annualized effect of the TIRA rate adjustment or the large cost customer revenue adjustment since the 2017 data would fully reflect the impact of these changes.

The Company counters that the Staff's position would result in a mismatch between costs and revenues since the Staff acknowledges that, at least partially, 2017 revenues are related to investments made in 2017 and the Staff has not made any adjustment for known and measurable investments in 2017. In addition, the Company argues that if either the OPA's proposal or the Staff's proposal is used, operating expenses would also have to be updated to reflect conditions in 2017. In support of its position, the Company cites the Commission's decision in *Northern Utilities d/b/a Unitil, Proposed Base Rate Increase and Rate Design Modification*, Docket No. 2011-00092, Order Approving Stipulation, (Nov. 29, 2011) (*2011-00092 Order)* and the Company's most recent rate case, *Northern Utilities, Inc. d/b/a Unitil, Proposed Base Rate Increase and Rate Design Modification*, Docket No. 2013-00133, Order Approving Stipulation (Dec. 27, 2013). The Company also argues that OPA's calculation is mathematically wrong since the OPA divides actual weather normalized revenue with a simple average number of customers which does not account for the timing of customer additions during the year.

In its Brief the OPA argues that the Company has made a number of known and measurable changes to expenses beyond 2016 including, property taxes which are based on 2018 amounts; payroll which is based on changes that will occur through January 1, 2018; and pension costs which are based on 2017 information. To adjust the Company's one-sided calculation of revenue requirements, the Commission should either annualize Northern's test year revenues, use the Company's 2017 revenues as proposed by Staff or alternatively, disallow Northern's proposed additions to rate base. OPA Brief at 8. In support of its position, the OPA points to the Commission's decision in *Camden and Rockland, Maine and Wanakah Water Companies, RE: Proposed Increase In Rates*, Docket No. 1993-00145, Order (Part II) (July 12, 1994) (*Camden and Rockland)* which set forth the "matching" principle and *Bangor Gas Company, L.L.C., Request for Renewal of Multi-Year Rate Plan (35-A M.R.S § 4706)*, Order (Sept. 8, 2014) (*Bangor Gas)* where the Commission rejected Bangor Gas Company's (Bangor) proposed use of a year-end rate base. The OPA notes that the cases relied on by Northern, Docket Nos. 2011-00092 and 2013-00133, were both resolved by stipulation. Since the arguments on the Company's proposed use of a year-end rate base and the OPA and Staff proposals on sales adjustments are interrelated, we address these arguments together below.

2. Decision

As a general matter, construction work in progress (CWIP) amounts are not allowed in rate base and rate base is set on an average-year basis. *Bangor Gas* at 22. To the extent that year-end rate base is to be used, the revenue requirement should also reflect any associated sales growth. *Id.* In *Bangor Gas*, the Commission noted that Bangor had only proposed the addition of plant to year-end rate base. The Commission found that given Bangor's growth, it was very likely that the costs represent investment in mains and service lines that added new customers and added additional revenues for which Bangor did not make any adjustment. The Commission thus concluded that since Bangor had only adjusted rate base without any corresponding adjustment for sales growth, the adjustment would not reflect all of the known and measurable changes associated with placing these assets into service and thus rejected Bangor's proposed use of a year-end rate base. *Id*.

In the case before us, the Company reports its test year-end rate base to be **$177,677,749**.[6] This compares to its November 30, 2016 rate base of **$160,899,657** and December 31, 2015 rate base of $167,206,707. It is not possible to discern what part of the year-end plant additions are growth related or revenue producing. However, based on the information provided by the Company, it is apparent that a significant part of year-end investments would produce additional revenues. For example, during the period of 2013-2016 the Company added $131,606,453 to its plant in service. EXM 004-001. Of this amount, the Company considers $63,744,375 to be non-revenue producing property. EXM 004-009. In 2016, of the Company's total non-TIRA and non- TAB investments, the Company identified $2,330,917 for gas main extensions, $2,335,472 for new gas services, $1,307,751 for gas service upgrades, and $1,004,687 for meter installations and purchases. ODR 002-023.

In response to the Company's proposal to use a year-end rate base, the Staff proposed that a corresponding known and measurable adjustment to revenues be made based on 2017 actual weather-normalized revenues. The Company was critical of the Staff's position since 2017 revenues would also reflect additional revenues produced in 2017 as a result of 2017 investment and noted that the Staff acknowledged that this mismatch would occur. But the Staff also noted that if no adjustment were made, there would be a mismatch between plant added at the very end of 2016 and 2016 revenues since such revenues would not reflect the revenues produced by year- end plant. Tr. at 64-66 (Oct. 25, 2017).

The Commission agrees with the Company that the use of 2017 revenues would likely overstate the known and measurable adjustment which would result from using 2016 year-end plant balances. On the other hand, the use of 2016 revenues, without

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6 This amount does not include $4,132,346 in Saco TAB investment which the Company has proposed to include in rate base in this case and which is discussed in Section V.E.

any adjustment to reflect sales growth associated with the plant added at year-end, would not reflect any of the known and measurable changes related to placing those assets in service and would be contrary to the Commission's holding in *Bangor Gas.*

The Company also argues that while not as extreme as the Staff's proposal, the OPA's proposal mismatches the Company's rate base and operating expenses. As part of its opposition to the OPA's annualization adjustment, the Company argues that the OPA's methodology is critically flawed. Northern Brief at 35. The Commission agrees with the Company's point that since customer revenue is not evenly distributed during the year the OPA's calculation is likely not precise, although the degree of the imprecision cannot be defined. More importantly, however, the Commission finds that the OPA's annualization adjustment methodology does not accurately match 2016 year- end plant additions because it is based solely on customers added in calendar year 2016 and does not include any customers who began to take service in 2017 related to the year-end investments.

The Company is extremely critical of both the Staff and the OPA because they have not demonstrated the reasonableness of their adjustments. Northern Brief at 33- 37. In making these arguments, the Company appears to misunderstand both who has the burden of proof as well as the Commission's holding in *Bangor Gas*. Under the holding in *Bangor Gas*, rate base will be calculated on an average-year basis unless a corresponding adjustment for known and measurable sales growth associated with the year-end rate base has been put forward. It is the Company, not the Staff or the OPA who has the burden of proof on this issue.

The Company notes that the Commission used a year-end rate base in calculating its revenue requirement in Docket No. 2011-00092 and Docket No. 2013- 00133. Those cases, however, were resolved by stipulation. In approving the reasonableness of the use of the year-end rate base in Docket No. 2011-00092, the Commission noted that the global stipulation included a downward adjustment to rate base and was part of a resolution which addressed overall revenue requirements. *2011- 00092* Order at 7. Thus, while a year-end rate base may be reasonable to include as part of a stipulation resolving other revenue requirement issues, the Commission's decision in Docket No. 2011-000092 does not contradict the holding in *Bangor Gas*, nor dictate that the Commission use a year-end rate base in deciding this litigated case.

Because there is no suitable proposal in the record which would match Northern's year-end rate base with known and measurable revenue increases, the Commission rejects the Company's proposed use of a year-end rate base. Instead, in accordance with the holding in *Bangor Gas* and past practice, the Commission will utilize a 13-month average rate base based on the information provided by the Company in EXM 013-002.[7]

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7 For reasons described below, we make a different determination for the Saco TAB investments.

B. Gain on Sale of Forest Avenue Property

In 2015, Northern sold its Forest Avenue property in Portland. Northern received $1,374,285 in proceeds for this property, which had a net book value of $313,243. Northern also incurred a cost of removal of $43,838 which it charged against accumulated depreciation. This resulted in a net gain of $922,110. Northern recorded this gain in Account 421.1, Gain on Disposition of Property. ODR-003-024. Northern's accounting results in the gain not being reflected in the rate calculation.

1. Positions Before the Commission

As part of his direct testimony, the OPA's witness Mr. Morgan recommended that revenue requirements in this case be adjusted for the gain on the sale of the Forest Avenue property. Morgan Dir. Test at 11. Mr. Morgan noted that the Company retained the gain on the sale of the property located on Forest Avenue in Portland while including the entire cost of the replacement property in rate base. Mr. Morgan recommended that the gain be flowed back to ratepayers through a three-year amortization. Mr. Morgan reasoned that Northern's ratepayers were responsible for the depreciation costs associated with this property, have paid investors a return on their investment in the property while it was owned by the Company, and bore the risk of loss when sold. In its brief, the OPA argues that as a matter of fairness, ratepayers should receive the gain associated with the sale of the Forest Avenue property noting that if the Company is allowed to retain this gain, and treat it as being reinvested in capital additions as the Company argues it has done, ratepayers will: (1) not only never receive the benefit of the sale in return for the burden they bore in relation to this property; but (2) once those additions are completed, they will be required to pay a recovery of those new costs through depreciation as well as a return on such costs. To avoid this situation, the OPA now proposes that the gain be flowed back to ratepayers over a four-year period. The OPA also states that the flow back of this gain should also include a recognition of the regulatory liability and deferred taxes in rate base as recommended in the Staff Bench Analysis. OPA Brief at 9-10.

In the Bench Analysis, Staff recommended that Northern create a regulatory liability for the gain on the sale of the property and that the gain be flowed back to ratepayers through an annual amortization over a four-year period. Staff also recommended that the regulatory asset, after appropriate reductions for depreciation and deferred taxes, be used to reduce rate base. Specifically, a regulatory liability of $922,110 should be recorded in Account 254, Other Regulatory Liabilities, to be amortized over a four-year period to Account 407.3, Regulatory Debits. The Staff also recommended that a deferred tax debit of $367,830 should also be recorded. ($922,110 x 39.89% Statutory Tax Rate). Bench Analysis at 2.

The Company disagrees with the position of the Staff and the OPA stating that the recommendations are inconsistent with sound ratemaking principles. Northern argues that because the transaction happened in 2014, the gain is outside of the 2016 test year, and that any related operating costs are not reflected in the 2016 test year. Northern Brief at 12. Northern also states that the asset was not fully depreciated and opines that the "return on" an asset reflects the recovery of the financing costs of an asset. Northern goes on to state that the "gain" on the sale of the Forest Avenue property was simply an accounting recognition, consistent with the requirements of the FERC Uniform System of Accounts, which the Company reflected in its financial statements for one period only. Northern did not "retain" the gain for the benefit of the shareholders, rather it reinvested the proceeds in its distribution system for the benefit of ratepayers. Northern further states that in addition to receiving the benefit of an improved distribution system, ratepayers also avoided payment of any costs that the Company would incur if it were to borrow an equivalent amount of money to invest in its system. *Id.* at 13.

Northern argues that the Staff and the OPA's proposed ratemaking treatment could result in Northern returning more to ratepayers than the gain it actually received from the sale. *Id* at 12-15. Thus, Northern requests that if the Commission agrees with the Staff and OPA positions, then the amortization should be accomplished through an annual reconciliation mechanism. *Id* at 16. Finally, to the extent the Commission adopts the amortization proposal of the Staff and the OPA, Northern suggests the Commission should follow past precedent outlined in *Central Maine Power Company, Annual Price Change Pursuant to the Alternative Rate Plan*, Docket No. 99-00155, Order on CMP's Motion for Reconsideration (Jan. 20, 2000) and allocate, at a minimum, ten percent of the gain to the Company. *Id.* at 17.

2. Decision

In *Casco Bay Lines v. Public Utilities Commission,* 390 A.2d 483 (Me. 1978), the Law Court affirmed the Commission's 90% allocation to ratepayers and 10% allocation to shareholders of the gain on the sale of three vessels. The Commission spread the net gain over a period of three years. Although the Commission acknowledged that ratepayers should primarily receive the benefits from the sale of depreciable assets, the Commission concluded that shareholders should retain 10% of the gain in order to maintain an incentive for the utility to achieve the best possible purchase price. The Law Court affirmed the Commission's decision, stating:

> It is entirely reasonable to redistribute those excessive depreciation payments back to the ratepayers by means of future reductions in Casco's depreciation expense. Furthermore, we note that when a utility sells property at a loss it is generally allowed to amortize such loss as an expense to be recovered from its ratepayers. It is only equitable that ratepayers who bear the cost of depreciation and maintenance on the property should be entitled to benefit from the sale of such property at a gain.

Id. at 489 – 490 (citations omitted).

In *Central Maine Power Company's Annual Price Change Pursuant to the Alternative Rate Plan*, Docket No. 1999-00155, Order on Issue of Proceeds from Sales of CMP Easements to Gas Pipeline Companies (Aug. 2, 1999) (*CMP*), the Commission extended this analysis to include non-depreciable as well as depreciable property since ratepayers bear the risk of loss on non-depreciable as well as depreciable property. *CMP* at 10.

In this instance, Northern's ratepayers have paid the depreciation expense associated with the Forest Avenue property and have borne the risk of loss when sold. Ratepayers have also provided investors with a return on investment throughout the period that the property was owned by Northern. As the Commission has noted previously, since investors are not entitled to a return on the fair value of rate base, they "do not possess a vested right in value-appreciations accruing to in-service assets." Id. at 10.

The Commission agrees that the sale took place outside of the test year but does not find that fact relevant in the determination of whether ratepayers should benefit from the gain. The Company has control over the test year and, to some degree, when the sale is recognized. This is shown clearly by the fact that the sale took place in 2014 and was not recognized on Northern's books until 2015. Transactions related to plant and plant adjustments are recognized on the balance sheet on a utility's books at original cost and remain there until either retired or sold whereas operating expenses are recorded in the current year only and reflected as part of the income statement. Utilities frequently are allowed by regulators to take costs that are either extraordinary in type or dollar level that accounting rules would require being expensed in one year and defer those costs for future recovery even though those expenses were not incurred "during the test year". *Public Utilities Commission, Investigation of Stranded Cost Recovery, Transmission and Distribution Utility Revenue Requirements, and Rate Design of Bangor Hydro-Electric Company*, Docket No. 1997-00596, Accounting Order at 5 (Sept. 8, 1999). The sale of an asset such as the Forest Avenue Property is not a usual transaction for a utility and, therefore, warrants special treatment, similar to that of an extraordinary gain. While Northern had information regarding the transaction back in 2014, the Commission did not. Had the Commission been informed of the sale at the time, it could have ordered the deferral of the gain through an accounting order until specific treatment was decided during a full rate proceeding.

Northern cites FERC accounting rules as directing the accounting for the sale of the gain. The Commission notes, however, that FERC accounting rules allow for the recording of regulatory assets and liabilities in those instances where ratemaking and accounting are inconsistent. Moreover, in *CMP*, the Commission, quoting *Democratic Central Committee v Washington Metropolitan Transit District*, 485 F. 2d 786, 821 (D.C. Cir. 1973), noted:

> Accounting procedures are not self-justifying; like other regulatory action of the commission, they must reflect a rational allocation of economic rights and responsibilities between a utility's investors and consumers. The simple fact that an agency treats an item a certain way for purposes of

> uniform system of accounts does not mark the end of judicial scrutiny; on the contrary, a reviewing court must assure itself that the accounting practice prescribed is consistent with underlying substantive principles of public utility law. To permit an accounting device to dictate the rule of law is to allow the tail to wag the dog.

Id. at 6-7.

Northern's argument that the property had not been fully depreciated is not relevant as the gain is calculated using the net book value which reduces the amount to be returned to ratepayers. Therefore, the Company has recovered the undepreciated amounts through the sale of the property. The Company's statement that the "gain is simply an accounting recognition" is without merit. If the Commission were to take Northern's statement to its broadest application, it could determine that everything was "simply an accounting recognition" as the accounting records are the basis and support for the rate proceeding and not allow anything in rates.

The Commission also does not find validity in the Company's statements that characterize this transaction as essentially a refinancing or the financing of replacement assets. Northern could have treated the proceeds similar to a Contribution in Aid of Construction and reduced the value of the assets by the gain. That would have in turn reduced the asset balance that Northern's depreciates and calculates a return on which would have allowed ratepayers to receive the benefit of the gain. This did not happen, however. It is not clear what Northern did with the cash from the sale. To the extent the Company reinvested the cash in property, its books reflect such investment as shareholder and not ratepayer investment.

Northern also takes exception to the Staff and OPA's proposal that the gain be returned to ratepayers over a four-year period with the amortization reflected in the cost of service with a reduction in rate base for the regulatory liability, net of the appropriate deferred taxes. Northern takes the position that by doing this, unless it files another rate proceeding, more than the gain would be returned to ratepayers. The Commission notes that rates are set with rate base at a point in time and after that point, the Company continues to depreciate property but earns a return based on the book value of the property at the time rates were set. There is no ongoing reconciliation to reflect the continued change in book value. The Commission sees no difference between the treatment of the regulatory liability and the treatment of other assets on the Company's books.

Lastly, Northern states that the Commission should follow previous precedent and allow it to keep at a minimum 10% of the gain as an incentive to ensure the Company works to get the best possible gain for ratepayers. Consistent with our holding in *CMP.* the Commission agrees that Northern should be allowed to keep 10% of the gain as an incentive to act in ratepayers' greatest interest in the future**.**

In conclusion, the Commission determines that Northern should return 90% of the gain on the sale of the Forest Avenue property in Portland to ratepayers by recording a regulatory liability on its books to be amortized over a four-year period. To reflect the fact that the liability will begin to be amortized in the rate-effective year, the liability should be reduced by one-half-year's amortization. The rate base reduction should also be offset by the appropriate amount of deferred taxes.

C. Depreciation Expense

1. Positions Before the Commission

As part of its direct case in this matter, Northern filed a depreciation study prepared by Paul Normand and proposed new depreciation rates and revenue requirement changes as a result of the proposed new depreciation rates. On an overall basis, the Company proposes a $590,286 increase in its annual accruals. Normand Dir. Test. at 11. The Staff retained the services of William Dunkel, a utility depreciation rate consultant, to review and analyze Mr. Normand's study and analysis. As part of its Bench Analysis, the Staff submitted the Bench Report of William Dunkel.

In his Bench Report, Mr. Dunkel challenges the Company's proposed accruals in the following three different accounts: Account 376.20-Mains Coated/Wrapped; Account 380.00-Services; and Account 376.40-Mains Plastic. On an overall basis, Mr. Dunkel recommended a $1,224,768 reduction to Company's proposed accrual. The primary driver in this difference was the different net salvage factors for all three accounts. In addition, Mr. Dunkel recommended a change in the average service life for account 376.40 which produced a $241,199 accrual reduction.

The largest adjustment ($942,242) proposed by Mr. Dunkel related to Account 380-Services. With regard to this account, Mr. Dunkel notes that actual average annual net salvage costs during the 2014-2016 period have been $516,393. Dunkel Bench Report at 14. Mr. Dunkel also used a three-year average, based on booked costs, to calculate the annual salvage costs for Account 376.40 Plastic and Account 376.20 Mains-Coated/Wrapped. In order to be conservative, Mr. Dunkel adjusted the salvage costs up by a ratio of 1.8 in the case of services, and by 1.7 in the case of Mains- Plastic. Figure V.5 below presents a summary of Mr. Dunkel's net salvage accrual proposals compared to those presented by the Company.

Figure V.5

	Net Salvage – Annual Amounts: Three-Year Average Booked Incurred	Company Proposed Accrual	Ratio: Company Proposed Accrual/ Incurred	Bench Report Proposed Accrual	Ratio: Bench Report Proposed Accrual/ Incurred
Total All Account:	$1,341,243	$2,776,306	2.1	$1,971,647	1.5
376.20 Mains-Coated/Wrapped	$ 179,169	$ 122,568	0.7	$ 184,617	1.0
376.40 Mains-Plastic	$ 225,608	$ 540,775	2.4	$ 392,400	1.7
380.00 Services	$ 516,393	$1,771,416	3.4	$ 928,211	1.8

Source: Dunkel Bench Report at 16.

In addition to recommending changes to the Company's accrual rates based on net salvage, Mr. Dunkel proposed a change in the Average Service Life (ASL) for Account 376.40, Mains-Plastic. For this account, the Company proposed an ASL of 55 years. According to Mr. Dunkel, however, the Company data indicate a longer life. Specifically, in the Company's simulated Plant Balance Analysis (SPR-BAL) the four best fits to the actual plant balances had an ASL of 67 years or higher. The best fit to the actual data (best Conformance Index) with a Retirement Experience Index that is at least "Fair", was 67 years. Mr. Dunkel thus recommended an ASL of 60 years for Account 376.40. In dollar terms, the increase in the ASL for this account reduced the Company's accruals by $241,199.

Mr. Normand, on behalf of the Company, responded to Mr. Dunkel's recommendations by way of his Rebuttal Testimony filed on November 13, 2017. Mr. Normand testified that Mr. Dunkel's recommendation on the higher ASL was not reasonable because Mr. Dunkel relied on the Conformance Index and ignored the Retirement Index. According to Mr. Normand, the authority on these issues, Mr. Baughan, requires that the Retirement Index be at least Good (above 50%) and the Retirement Index for Mr. Dunkel's life curve was only Fair. Therefore, Mr. Dunkel's recommendation should be disregarded. Normand Reb. Test. at 8,6-9. In contrast, Mr. Normand notes that his ASL curve satisfied Mr. Baughan's requirements. *Id.*

With regard to Mr. Dunkel's net salvage recommendations, Mr. Normand testified that Mr. Dunkel's recommendations use data from non-related utilities and thus, are arbitrary and not supported by NARUC or any other authoritative source. Mr. Normand goes on to testify that Mr. Dunkel's recommendations have no company-specific support and appear to be designed solely to establish an adjustment to reduce the

Company's costs. *Id*. at 10-11. Finally, Mr. Normand criticizes Mr. Dunkel's use of historical three-year averages of salvage costs since it ignores the lag that it takes to get such costs approved in rates and the fact that such costs are constantly increasing over time. *Id* at 13.

In his Reply Bench Report filed on December 5, 2017, Mr. Dunkel responded to Mr. Normand's testimony by stating that he did not in fact rely on data from other companies as part of his analysis here. While Mr. Dunkel notes that he did make reference to his methodology being used by other companies, this is wholly different than relying on data from those companies. Dunkel Reply Bench Report at 2-7.

2. Decision

a. Average Service Lives

Mr. Dunkel proposed changes to the ASL for only one account, thus, there is only one ASL calculation in dispute in this case, Account 376.40-Mains-Plastic. Both Mr. Normand and Mr. Dunkel utilize the standard Iowa Curves ASL methodology to determine the ASL for this account. The curve selected by Mr. Normand results in his recommendation of 55 years, while the curve selected by Mr. Dunkel yielded a service life of 67 years and led to his recommendation of a 60-year service life. Both Mr. Normand and Mr. Dunkel rely on the article by Alex Baughan as the authoritative source on the use and selection of ASL curves in utility depreciation calculations.[8] The threshold question before us is whether Mr. Dunkel's analysis and recommendation satisfies the criteria set forth by Mr. Baughan.

According to the Baughan criteria, in order for the life curve selected to be considered entirely satisfactory, it should be required that both the retirement experience index and the conformance index be "Good" or better. If the retirements experience index is "Poor" or "Valueless", the result should not be accepted even if the conformance index is. In those cases, where the retirement experience index is "Fair", the life determination should be "examined critically and if it is not supported by reasoned judgment, it should be accordingly modified." Baughan at 62-63. According to Baughan, the conformance index is considered to be "Excellent" if it is over 75 and "Good" if it is between 50 and 75. Retirement index results are considered "Excellent" if they are over 75, "Good" between 50 and 75, "Fair" from 33 to 50.

The life determination curve selected by Mr. Dunkel had a conformance index score of 184, in the "Excellent" range, and a retirement index of 35 or "Fair". Under the Baughan criteria then, Mr. Dunkel's results do not need to be rejected outright. However, in comparing Mr. Dunkel's ASL recommendation to Mr. Normand's recommendation, we believe the Normand recommendation to be superior here.

8 *See* Life Analysis of Utility Plant for Depreciation Accounting Purposes by the Simulated Plant-Record Method, Alex E. Baughan (Dunkel Bench Report, Attachment WDA-5) (Baughan).

The ASL curve selected by Mr. Normand produced a conformance index score in the “Excellent” range and a retirement index score in the “Good” range. Therefore, according to the Baughan criteria, Mr. Normand’s recommended ASL would be considered “entirely satisfactory”. Thus, while Baughan’s criteria does not require that we reject Mr. Dunkel’s result, the Commission finds that Normand’s proposed ASL selected curve produces superior results and, therefore, will accept the Company’s recommendation here.

b. Net Salvage

Gross salvage value refers to the value that is received for plant when it is retired from service. Cost of removal is the expenditure incurred in connection with retiring, removing and disposing of property when it is retired. Historically, net salvage value has been reflected in utility depreciation rates. The underlying rationale for doing so is to match costs with the utility ratepayers who benefit from the investment. Public Utility Depreciation Practices, NARUC (August 1996) at 157.

While easily stated in theory, accurately calculating net salvage costs in practice is not an easy task. This is because the calculation is based on forecasts of costs that will occur years into the future. Indeed, this difficulty has led a number of utility commissions to abandon the practice of incorporating net salvage costs into depreciation rates and to move to current-period accounting for the recovery of net salvage values. The move to current-period accounting, apparently, has been accelerated by the fact that generally, at this time, cost of removal exceeds gross salvage resulting in negative net salvage values. *Id.* at 158.

The Commission in this case has been presented with two methodologies for calculating net salvage. The methodology employed by the Company’s witness, Mr. Normand, derives net salvage by calculating the net salvage percentage by dividing recent historical removal costs by the original cost of the plant when placed in service. Mr. Normand then applied judgement in adjusting these values down to what he considers to be conservative. Tr. at 13-14 (Nov. 13, 2017). Mr. Normand’s approach has been referred to in this case as the “traditional” approach.

An “alternative” approach for calculating net salvage for three accounts (Distribution Services, Mains-Plastic and Mains-Coated/Wrapped) has been presented by Mr. Dunkel on behalf of the Commission Staff. To calculate net salvage for these three accounts, Mr. Dunkel took the most recent three-year average of removal and then adjusted the average up by a ratio of 1.8 in the case of Services and 1.7 in the case of Mains-Plastic. In the case of Mains-Coated/wrapped Mr. Dunkel essentially used the three-year average.

In comparing the two methodologies presented here, both Mr. Normand and Mr. Dunkel looked at recent historical data and used these results to project the future cost of removal. The Company argues that the NARUC manual states the “the process should start” by looking at historical data and that instead of just starting there, Mr. Dunkel also finished there. Northern Brief at 63. In contrast, Mr. Normand used this historical data and looked at the relationship between salvage costs and plant by dividing salvage costs by the original cost of the retired plant, which is consistent with the methodology set forth in the NARUC manual.

The Commission agrees with the Company that Mr. Normand's methodology is consistent with the NARUC manual. We also conclude, however, that this approach is not mandated or directed by the manual. Indeed Mr. Normand acknowledged that there are a number of ways that salvage value can be calculated. Tr. at 10 (Dec. 13, 2017).

In looking critically at Mr. Normand's methodology, our concern is the mismatch which results from deriving a salvage ratio based on costs of removal from today and plant investment costs from decades ago. This results in salvage ratios which are many times higher than the ratios that would result from using current levels of plant investment and current accruals. Mr. Normand, himself, recognized the mismatch and addresses the issue by ratcheting the number down based on his judgment. Tr. at 13- 14 (Dec. 13, 2017). In looking at the Services account, the average service life for this asset is 50 years. Assuming the asset retired in 2016 had an "average life", the dollar invested in 1966 for the asset was approximately 1/7 of the value of the dollar that was spent for removal. *Id*. at 35-36.

In contrast to Mr. Normand's approach, Mr. Dunkel relied solely on the current level of removal costs. The Company argues that by looking solely at current removal costs and not tying such costs to the Company's investments, there is no basis to determine what future costs of removal should be recovered from today's ratepayers. The Commission finds the concern that Mr. Dunkel's methodology understates the future cost of removal to have validity. Mr. Dunkel addresses this concern by using his judgment and adjusting cost of removal numbers up to reflect the impact of inflation on future costs of removal. Reply Bench Report at 8-9. For example, with regard to the Services account, as noted previously, the three-year average for the cost of removal was $516,393. Mr. Dunkel adjusts this number up by approximately 80% to $928,211. In looking at both of the analyses before us, then, both Mr. Normand and Mr. Dunkel applied their judgment to their base calculations which would otherwise be invalid or unacceptable. Ultimately, the Commission must apply its judgment and decide what is just and reasonable to the Company's ratepayers, both present and future, and the Company's shareholders. In doing so, the Commission is cognizant of the Company's current investments and costs of removal resulting from prior owners' failure to invest which suggests that, to some extent, the current costs of removal may be relatively higher than might be expected in future years. The Commission, therefore, will adopt Mr. Dunkel's net salvage recommendations for accounts 376.20, 376.40, and 380, finding that Mr. Dunkel's methodology, given current circumstances, will both ensure that the Company is compensated for its actual net salvage costs over the coming years and that current ratepayers are not unnecessarily burdened with forecasts of costs related to past failures to invest and which have been discontinued.

In accepting Mr. Dunkel's recommendations here, the Commission notes that the

Company argued that Mr. Dunkel had not in fact based his net salvage cost calculations on Company data. Normand Reb. Test. at 11. The Company, however, walked back from this claim both in discovery and at the hearing. EXM 012-004 and Tr. 9 (Dec. 13, 2017). To the extent that the Company is still alleging such, the Commission's review of Mr. Dunkel's Bench Report and Reply Bench Report demonstrates the contrary.

Finally, the Commission notes the Company's argument that Mr. Dunkel's methodology has been rejected in other jurisdictions. [9] The Company is correct in its assertion, but Mr. Dunkel's methodology has also been accepted elsewhere.[10] The Company argues that the decisions that have accepted Mr. Dunkel's Methodology have involved electric utilities and not gas utilities. The Commission notes that the NARUC Manual makes no distinction between gas utilities and electric utilities in the calculation of net salvage values. Nor has the Company provided any statistical analysis or data in support of its position here. Therefore, the Commission finds no reason to disrupt its findings and conclusions set forth above based on the decisions in other jurisdictions.

D. Expense

1. Payroll Expenses

a. Inclusion of Incentive Compensation in the Calculation of Payroll Adjustment

i. Positions Before the Commission

The OPA states that Northern has improperly inflated payroll expense by applying its annual merit increases to the total payroll amount, including incentive compensation. The OPA argues that the effect of doing so increases the incentive compensation as if it were increased annually by merit rather than being dependent on actually being earned. OPA Brief at 15-16. The OPA goes on to state that in order for incentive compensation to effectively be extra compensation it must be awarded based on performance and not as part of base pay and, therefore, should not be increased by merit pay.

Northern asserts that the OPA misunderstands the way in which the Company determines incentive compensation. Northern Brief at 21. The Company explains that awarded incentive compensation is calculated as a percentage of base pay and is, therefore, effectively subject to a merit increase each year. For example, the merit increases that took effect on January 1, 2016 were included in the base pay earnings on which the 2017 incentive compensation payout for 2016 performance was based.

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9 *See In re Consumers Energy Company*, Michigan Public Service Commission, Case NO. U-15629 Opinion (Sept. 29, 2009).

10 *See NSTAR and Western Massachusetts Electric Company, Petition for Approval of General Increases in Base Distribution Rates*, D.PU. 17-05, Order Establishing Eversource's Revenue Requirement (Nov. 30, 2017).

Similarly, the merit increases that took effect on January 1, 2017 will be included in the base pay earnings on which the 2018 incentive compensation payout for 2017 performance will be based. *Id.*

ii. Decision

The incentive plan documents explain that incentive compensation is expressed as a percentage of the participant's base salary earned during the performance period. EXM-001-002 Attachments 1 & 2. It follows mathematically that if base salaries increase, the incentive payout would increase at the same payout percentage. The Company has awarded incentive compensation at least at the target level annually since at least 2013. OPA-004-014. In this case, the Company has made an adjustment to reduce the test year incentive compensation payment to the target level before applying the applicable merit increases. Shaw Dir. Test. at 7. Given the mechanics of Northern's calculations, the Commission finds that it is appropriate to include the incentive payment in the calculation of the payroll adjustment as computed by Northern. The recoverability of incentive payments in general are discussed later in this section.

b. Capitalization Ratio

i. Positions Before the Commission

The OPA recommends that Northern should apply the same capitalization ratio to both payroll and benefit expenses. OPA Brief at 17. The OPA further proposes that the capitalization percentage for each division be calculated based on a three-year average of 2014, 2015 and 2016. *Id*. Currently, Northern calculates one rate for payroll based on actual payroll costs charged to capital projects (50.29 percent for Northern and 31.90 percent for USC), and a separate rate for benefits based on a 4-year average of the time charges (48.91 percent for Northern and 34.03 percent for USC). The OPA argues that because employees track their time based on the nature of the work and time records are used to charge their time to capital projects, it is appropriate to use a historical average in calculating the allocation percentage and proposes a 3-year average. *Id*. The OPA calculated a capitalization rate of 50.40 percent for Northern and 33.05 percent for USC to be applied to both benefits and payroll. *Id*.

Northern argues that its method for determining the capitalization percentages is properly based on the Company's experience and judgment. Northern Brief at 23. The Company states that labor charges for payroll are not significantly volatile, therefore, actual test year charges are most representative. *Id*. With respect to benefits, Northern argues that the allocation between capital and expense is best aligned with time spent on projects rather than labor and are subject to greater variability making its 4-year average most appropriate. *Id*. It is the Company's position that its use of separate capitalization percentages for payroll and benefits is most accurate and that the OPA has not demonstrated that a 3-year average is more effective than the 4-year average currently used by the Company in deriving its benefits capitalization rate.

ii. Decision

Northern explained that the payroll capitalization rate “is derived from actual time charges for O&M and Construction payroll” and that the benefits rate “is derived from a 4-year average of the historical payroll data.” EXM-001-006 and EXM-001-007. The Company further explains that the benefits allocation “is aligned with time spent on projects, rather than labor, and as such is subject to greater variability from year to year [than payroll].” Northern Brief at 23 (Emphasis in original). The Commission does not understand the distinction between “labor” and “time spent.” Although the Commission does not dispute that benefit costs likely have greater variability from year to year than payroll costs, it is not clear to the Commission how averaging time spent on projects accomplishes the Company’s apparent objective of smoothing those cost fluctuations. The Commission also does not understand why it is necessary to smooth the fluctuations since the benefit amount capitalized or expensed should be reflective of that variability.

The OPA proposed a combined adjustment of $133,466 for the removal of incentive payments from the calculation of the merit increase and its proposed change to capitalization rates. OPA Brief at 17. The OPA did not quantify each adjustment, however, it can be inferred that the adjustment proposed by the OPA related to the change in capitalization rates is less than $133,000. The OPA did not propose a corresponding increase to rate base, arguing that it is not necessary. The OPA’s adjustment is prospective and is intended to reflect the cost incurred on an ongoing basis. OPA Reply Brief at 6. The Company argues that if the amount charged to expense is lowered, the Company’s rate base must be increased to match the increase in the amount charged to capital. Northern Brief at 24.

The test year reflects the expenses and rate base using the actual capitalization rates adopted by the Company during the test year and are, therefore, properly matched. It appears that the change in the capitalization rates would have only a small impact on the revenue requirement and would require a recalculation of the rate base amount. The Commission finds that it is not necessary to adjust the capitalization rates for the purposes of determining the revenue requirement in this case. However, as explained above, the Commission does not see the benefit of using separate capitalization ratios for payroll and benefits, and therefore recommends that the Company review its accounting policy and consider applying a single capitalization ratio to both payroll and benefits.

2. Incentive Compensation

Northern has included incentive compensation, which it provides as a part of the total compensation package to employees, as part of its O&M expenses. The Company offers three different incentive plans: Incentive Plan, Management Incentive Plan and a Stock Plan. The Incentive Plan is available to employees of eligible subsidiaries, including Northern and USC, who are not eligible for the Management Incentive Plan. The Management Incentive Plan is available to designated management employees. The Stock Plan is available to all non-union employees. The accounting for each plan is similar in that costs are expensed or capitalized based upon where the employees' time is recorded. The Company included an adjustment to reduce the test year incentive compensation to the payout expected at the target level.

a. <u>Position of the Parties</u>

Staff recommended a $554,655 reduction to O&M expenses for the incentive compensation related to earnings per share (EPS) and electric reliability standards. Bench Analysis at 24-25. Staff reasoned that the EPS metric primarily benefited shareholders rather than ratepayers and, therefore, the cost for incentive payments related to EPS goals should be excluded from the revenue requirement. Similarly, Staff stated that Northern's Maine gas customers should not bear the cost of incentives paid to achieve electric reliability standards for other subsidiaries in other jurisdictions.

In calculating the amount of the disallowance, Staff interpreted the Incentive Plan and Management Incentive Plan as being based on five separate metrics. These metrics included EPS, which made up 40% of the target level payout, and electric reliability which made up an additional 10% of the payout amount. Staff interpreted the Restricted Stock Plan as being wholly attributable to EPS and, therefore, recommended disallowance of all Restricted Stock Plan incentive payments. In its rebuttal testimony, the Company clarified that the same five performance metrics used in the other incentive plans are also applicable to the Restricted Stock Plan. Shaw Reb. Test. at 7.

The OPA made a similar argument as Staff, stating that costs for incentive programs must be adjusted to remove the portion associated with earnings goals or increasing earnings. OPA Brief at 12. The OPA argues that Northern's assertion that higher earnings directly benefit ratepayers is nothing more than a description of a financially healthy company that is already required by statute. In addition, the OPA points out that if the Company fails to meet the metrics necessary to award incentive compensation, the Company will have collected through rates amounts intended for incentives that are not paid to employees, and, therefore, are retained by the Company. In its Brief, the OPA also adopts the Staff's recommendation to exclude incentive payments attributable to electric reliability metrics. *Id*. at 15.

The OPA takes issue with Northern's argument that the full incentive compensation amount must be included in the revenue requirement because they are necessary to provide compensation consistent with market levels allowing the Company to attract and retain qualified employees. Northern presented findings of the Company's compensation consultant, Towers Watson, which compares Northern's compensation to those in proxy or peer groups (Towers Watson Study).[11] **[BEGIN CONFIDENTIAL]*** *

11 *See* EXM-001-001 Attachments 1 and 2 (Confidential).

*** ***
*** *[END CONFIDENTIAL]**

Northern asserts that it must be able to pay its employees reasonable market level compensation so that it can meet the Company's service obligation to customers and that the Company's overall compensation, including incentive compensation, is consistent with that objective. Northern Brief at 27. The Company's position is that the Towers Watson Study demonstrates that its total compensation is aligned with, or below, the market median. Northern suggests that the Commission should look at the reasonableness of the overall level of compensation and contends that disallowing components of the incentive payment as recommended by Staff and the OPA effectively penalizes the Company for the way in which it structures is employee compensation. *Id.* at 28.

In addition, the Company argues that EPS is a comprehensive measure of the financial condition of the Company and, therefore, directly benefits ratepayers. *Id.* at 29. Northern reasons that only a financially healthy company can raise capital at a reasonable cost which provides a direct benefit to ratepayers.

b. Decision

The OPA argues that **[BEGIN CONFIDENTIAL]*** **[END CONFIDENTIAL]** The Commission considers the Towers Watson Study a reliable source that supports Northern's position that its overall compensation is in line with the market median and not excessive.

The OPA also asserts that if Northern's base salary is in line with market levels, that should be sufficient to hire and retain qualified employees. Northern contends that "[i]f the Company were to pay only base salaries at the median market level, without incentive compensation, it would obviously pay its employees overall compensation at a level well below the market median." Northern Reply Brief at 13. The Commission agrees with Northern that it is important to consider the reasonableness of the total compensation, including base pay and incentive compensation, paid to employees. It is not the Commission's place to dictate the exact structure of the Company's overall employee compensation scheme.

The Commission considered a similar issue concerning incentive compensation in *Northern New England D/B/A Fairpoint d/b/a Consolidated Communications/NNE, Request for Increase in Rates and for Maine Universal Service Fund Support for Provider of Last Resort Service Pertaining to Northern New England D/B/A FairPoint Communications*, Docket 2013-00340, Order at 61-63 (November 21, 2014) (*FairPoint Order*). In the *FairPoint Order*, the Commission concluded that there was no evidence that FairPoint's "overall compensation levels [were] unreasonable." *FairPoint Order* at 63. The Commission declined to make any adjustments to the incentive expense on that basis. *Id.* Although there may be circumstances under which it is appropriate to exclude incentive payments, in the present case, the Commission finds that Northern's incentive compensation is a component of a reasonable overall compensation plan and, therefore, is properly included in the revenue requirement calculation as adjusted by the Company.

With regard to the electric reliability metric, Northern asserts that it is weighted the same as the gas safety metric in the incentive compensation calculation and, therefore, could be replaced with the gas safety metric with no impact to ratepayers. Northern Brief at 31. The Commission is not convinced by this argument. If the Company's actual performance results are different in the two metrics, it seems that the impact on the incentive payment calculation would not be identical or offsetting. Nevertheless, because the Commission determined that the overall total compensation is reasonable, no adjustment for electric reliability is necessary.

In addition, the Commission understands the OPA's point that incentive payouts are dependent on the Company meeting established performance goals and, therefore, are not guaranteed. The Company, however, has met its performance metrics and made incentive payments at the target level or above each year for at least the last four years. OPA-004-014. Therefore, the Commission believes that it is not unreasonable to include the incentive payments. The record lacks sufficient evidence to support removal of the incentive payments beyond that already made by the Company from the test year expenses on the basis that they may not occur.

3. Inflation Adjustment

a. Positions Before the Commission

In its direct case, the Company proposed to adjust "residual O&M expenses" (all expenses not otherwise adjusted for known and measurable changes or not subject to inflation) by a general inflation rate as measured by changes in the Gross Domestic Product Implicit Price Deflator (GDPIPD). The Company inflation adjustment is based on a 3.63% cumulative inflation rate which represents the increase in the GDPIPD from the mid-point of the test year, July 1, 2016, to the date of the proposed rate change, March 1, 2018. The application of the inflation rate to the residual O&M expense category produces an adjustment of $150,416 to revenue requirements.

In the Staff's Bench Analysis, the Staff took the position that the Company's proposed inflation adjustment was not a known and measurable change and was not appropriate to include as a test year adjustment to O&M expenses. The Staff stated that the adjustment was appropriate as part of an attrition analysis which would include an adjustment for forecasted sales by the Company. However, the Company did not include an attrition analysis as part of its case here. Bench Analysis at 22-13.

In response to the Staff's position on this issue, the Company argues that there is no question that the Company's operating and maintenance expenses will be subject to inflationary pressures. The Company notes that the inclusion of an inflation adjustment is a practice that has long been used by Northern's affiliates in setting rates. Northern Brief at 18. In support of this position, the Company cites a Massachusetts case where a Northern subsidiary was allowed to increase its test-year O&M expense by an independently published price index from the mid-point of the test year to the mid-point of the rate year. *Petition of Fitchburg Gas and Electric Light Company d/b/a Unitil*, MA PPU 15-80/15-81, Final Order at 186-187 (Apr. 29, 2016) (*Fitchburg Gas and Electric)*. The Company further argues that the Company's use of the historic and projected GDPIPD index is consistent with Maine precedent where the Commission found that the best method to calculate actual inflation was to utilize a government source. *Emera Maine, Request for Approval of Proposed Rate Increase*, Docket No. 2015-00360, Order – Part II (Dec. 22, 2016).

In its brief, the OPA argues that the Company's proposed inflation adjustment must be rejected because it is not a known and measurable change. Rather, the adjustment is based on the use of an inflation forecasting tool which may produce results that vary from actual levels of inflation and, thus, are not reasonably certain. Finally, the OPA notes that increasing O&M expenses by an across the board inflation adjustment ignores the reality that Northern's distribution expenses have decreased since 2015. OPA Brief at 24.

b. Decision

The Commission has in the past distinguished adjustments made as part of an attrition analysis and known and measurable adjustments to the test year. An attrition analysis is largely based on forecasts and, by its nature, involves a lesser degree of certainty. *Bangor Hydro-Electric Company, Proposed Increase In Rates*, Docket No. 97-116, Order at 21 (Feb. 9., 1998). In contrast, when making test year adjustments, the Commission has applied a strict known and measurable stand. Specifically, to be "known", the change to the test year must be reasonably certain as to whether and when it will occur and to be considered "measurable", the amount of the change must be reasonably certain. *Camden and Rockland, Maine and Wanakah Water Companies, Proposed Increase In Rates,* Docket No. 93-145, Order (Part II) at 9 (July 12, 1994). In the case before the Commission, the Company has not proposed that its rates be adjusted based on a rate-effective year attrition analysis which would look at forecasts of both expenses and revenues. Based on the arguments presented, the Commission concludes that the Company's proposed inflation adjustment fails to qualify as a known and measurable change to test year expenses.

The Company's inflation adjustment in this case includes both an historical and projected component. As such, the changes to the expenses which the Company seeks to adjust here cannot be considered to be known or measurable. The Commission acknowledges that as a general matter, a utility's costs are subject to inflationary pressures. The fact that certain costs are subject to inflationary pressures, however, does not necessarily mean that an individual cost or group of costs will increase in lock-step with inflationary changes. Nor does this mean that the Company has no ability to keep cost increases at a level that is less than the rate of inflation. *See Bangor Hydro-Electric Company, Proposed Increase In Rates*, Docket No. 1993-00062 Order at 51 (Mar. 16, 1994) citing the dissent of Chairman Welch in *Central Maine Power Company Proposed Increase In Rates*, Docket No. 1992-00345, Order at 146 – 147 (Dec. 14, 1993). The Commission would also note that in the recent Emera Rate Case cited by Northern, the inflation adjustment utilized by the Commission as part of the attrition analysis included a productivity offset which reduced the annual escalation factor by 1.0% annually.

In response to the Company's reliance on *Fitchburg Gas and Electric*, the Commission finds this case law to be inconsistent with Maine precedent and declines to adopt it here. In addition, under the Massachusetts inflation adjustment procedure, before the Massachusetts Department allows a utility to recover an inflation adjustment, the utility must demonstrate that it has implemented cost containment measures. As this standard has not been adopted by the Commission, the Company's inflation adjustment was not measured or judged by this metric. The Commission thus rejects the Company's proposed inflation adjustment as a known and measurable change to the test year.

E. Saco TAB

1. Overview

On June 5, 2015, Northern submitted a Request for Commission Approval of its Saco TAB Program. Northern described the TAB program as being designed to provide the Company with a mechanism to build-out its distribution network incrementally in targeted areas to serve new customers who are currently off the main line. Northern explained that customers who are off the main line are typically required to pay a contribution in aid of construction (CIAC) up front before Northern can extend the main line and install a new service for the customer and that the CIAC is a significant barrier to consumers choosing to convert to natural gas. The TAB program would remove the CIAC barrier by replacing it with a monthly surcharge mechanism in specifically defined geographic areas in the City of Saco. The Company would assess a TAB surcharge to customers within the TAB expansion area for a 10-year period which is intended to recover the costs of the expansion over time from those customers that benefit from the expansion. Northern proposed that its TAB program take effect on January 1, 2016.

On December 22, 2015, the Commission issued an Order Approving Stipulation which authorized Northern's Saco TAB Program. As part of the Order Approving Stipulation, the Commission stated:

> The Commission will allow Northern's proposed terms and conditions to become effective January 1, 2016, as requested by Northern and the OPA, and as supported by the City of Saco. Nonetheless, in view of the uncertainty as to the projected rate of conversion to natural gas and the discretion afforded Northern in the stipulation to respond accordingly, the Commission makes no determination regarding the recoverability of TAB-related costs in a future base rate case proceeding, leaving that ratemaking issue open for consideration at the time Northern seeks to include any such costs in base rates.

Northern Utilities d/b/a Unitil, Request for Approval of Rate Targeted Area Buildout Program, Docket No. 2015-00146, Order Approving Stipulation at 5 (Dec. 22, 2015) (Saco *TAB Order*).

2. Positions Before the Commission

Northern's initial filing did not contain a request for recovery of any costs related to the Saco TAB. However, the Company submitted a supplemental filing on August 18, 2017, in which it requested that it be allowed to increase its rates by an additional $677,008 for Saco TAB revenue requirements. As explained by Mr. Chong in his Supplemental Testimony, the Saco TAB plant was gassed and in service by December 31, 2016, however, the Saco TAB investment was not closed to plant since the Company was still receiving invoices from vendors into 2017. Chong Sup. Test. at 2. The Company's proposed revenue requirement for the Saco TAB was based on a year- end plant investment of $4,132,346; a pre-tax return of $488,898 based on its cost of capital recommendation; depreciation expense of $108,025 based on the Company's proposed depreciation rates; and property tax expense of $80,085 based on the City of Saco's 2017 property tax rate. *Id.* at Sched. DLC-1.

The OPA does not object to the inclusion of the Saco TAB revenue requirement in this rate case since the Saco TAB plant was operationally in service at the end of the 2016 test year. The OPA does object to the Company's method of calculating the revenue requirement for the project stating that the Company has failed to take into account known and measurable changes. The OPA takes the position that in the case of the Saco TAB, it would be inequitable and a violation of the matching principle for the Company to be allowed additional revenue requirement for all capital investment relating to the buildout without taking into account depreciation, accumulated deferred taxes, and revenues from the surcharges. OPA Brief at 25-26.

OPA witness Mr. Morgan, therefore, suggests several adjustments to the Company's proposed revenue requirement. Specifically, Mr. Morgan proposed that the Saco TAB rate base be reduced to reflect surcharge revenues collected in 2017 of $10,058, accumulated depreciation of $107,991, and deferred taxes of $811,502. Mr.

Morgan also proposed that revenues from Saco TAB customers be applied against the TAB revenue requirement. The OPA concludes that the operating revenues related to these customers is known and measurable and calculated that amount to be $53,964. In proposing these adjustments, Mr. Morgan reasoned that the Saco TAB plant was not recorded as plant in service during the test year and therefore, the Company's inclusion of the costs is similar to adding post-test year plant. When adding post-test year revenue producing plant one cannot include only the costs, but must also reflect the revenue requirement and cost offsets. Morgan Dir. Test. at 38.

In its Bench Analysis, Staff agreed with Northern that it was appropriate to address the Saco TAB revenue requirement issues in this case. The Staff noted that in the Company's modeling in Docket No. 2015-00146 of the TAB rate base level, the Company deducted from gross plant investment amounts for accumulated depreciation, the forecasted TAB surcharge revenue and accumulated deferred income taxes. In its TAB revenue requirement proposal in this case, however, the Company failed to include any such deductions.

The Staff proposed including as an offset to gross plant investment, $788,596 for deferred taxes, including bonus depreciation. In addition, the Staff reduced the gross plant investment by the TAB surcharge revenue through 2017 which the Staff estimated to be $30,702. Making the adjustments results in a net plant investment of $3,226,055. Bench Analysis Exhibit 4 at 3. Applying the pre-tax WACC of 10.65% proposed by Staff in the Bench Analysis, results in a required return of $343,421 on the Company's Saco TAB rate base. *Id*. at 1. Applying the depreciation rates proposed by Staff's consultant to the Saco TAB investment reduces annual depreciation expenses from $108,025 to $89,247. *Id*. at 2.

Staff noted that the Company included in revenue requirements 2016 end of year plant investment along with 2017 expenses, but excluded entirely the revenue that will be received as a result of this investment and expense. Staff proposed that 2017 Saco TAB revenue be included as an offset to Saco TAB revenue requirements. The Company estimated 2017 revenue of $142,573. Based on the Staff's calculations and assumptions, the Staff estimated the revenue deficiency associated with the Saco TAB to be $362,894. *Id*. at 1.

With regards to Saco TAB ratemaking on a going forward basis, the Staff recommended that the Commission adopt a Saco TAB incentive mechanism to help ensure that the targeted customer and sales growth in the TAB area is achieved. Staff stated that the mechanism would work by establishing targeted levels of sales and surcharge revenues based on the Company's modelling in Docket No. 2015-00146. In setting the revenue requirement for the Saco TAB in the future, to the extent the Company did not achieve the target sales or surcharge revenue at 90% of the target levels, the deficiency would be imputed to the Company. On the other hand, if the Company achieved sales or surcharge revenue in excess of 110% of the target, such amounts would flow to the Company. The mechanism would be specific to the buildout areas approved by the Commission in Docket No. 2015-00146.

In response to the OPA and Staff proposals on the Saco TAB revenue requirement, the Company argues that the Saco TAB investment was made during the test year and that no post-test year changes are appropriate. Chong Reb. Test at 24. Specifically, the Company argues that there is no justification to treat the determination of rate base for the Saco TAB any differently than other rate base additions made during the test year. Northern states that the Saco TAB was operationally in service at the end of 2016, meaning that it was gassed and serving customers before December 31, 2016 but due to an accounting lag, it was not closed to the Company's books until the first quarter of 2017. Northern states that it completed and placed into service $4,132,316 in Saco TAB plant additions in 2016 which resulted in its proposed revenue requirement of $677,008. Northern Brief at 80.

Northern disagrees that the rate base should be reduced for accumulated depreciation as the depreciation expense would not have been recorded until 2017 and, therefore, the adjustment is outside of the test year. Northern makes similar points regarding proposed reductions in rate base for 2017 TAB surcharge revenue. *Id.* at 81. With regards to the proposed rate base adjustment for accumulated deferred income taxes, Northern states that since it is in a net operating loss (NOL) position, any deferred income taxes would be offset by the deferred NOL eliminating any rate base reduction. *Id.* at 82-83. The Company notes that ADIT represent deductions that the Company has reported on its income tax returns and has received a cash benefit from. The Company further explains that NOL carryforwards represent deductions that the Company has reported on its income tax returns but due to limitations associated with taxable income, the Company has not received a cash benefit for the deduction. Income tax and regulatory accounting requires that NOL carryforwards and ADIT be netted against each other to accurately reflect the cash benefit the Company has received for accumulated tax deductions. Because Northern is not currently able to take advantage of tax savings associated with ADIT the impact of the post-test year adjustment recommended by Staff and the OPA would be zero. In addition, requiring the Company to make the adjustment recommended by Staff and the OPA would effectively require Northern to be in violation of the Internal Revenue Service (IRS) normalization rules. *Id.* at 83.

Northern states that it is not appropriate to reduce the revenue requirement by estimated TAB revenues for 2017 noting that revenues collected in 2017 would also reflect amounts collected from 2017 plant additions, creating a mismatch as 2017 plant additions would not be reflected in rate base. Offsetting the Saco TAB revenue requirement with future revenues associated with post-test year plant in service will negatively impact the Company's ability to earn its allowed return on equity. *Id.* at 84.

Finally, Northern disagrees with Staff's proposed incentive mechanism. Northern opines that the Saco TAB Order in Docket No. 2015-00146, Order Approving Stipulation (Dec. 22, 2015) (*Saco TAB Order*), does not contemplate that Northern will be subject to a non-traditional ratemaking treatment of unknown design, to be introduced on a prospective basis at a later time that fundamentally alters the Saco TAB program. It states that the Stipulation and Order in Docket No. 2015-00146 cannot be read to suggest that the Company blindly agreed to and expected an "anything goes" approach to TAB ratemaking before it proceeded to commit significant resources and investment to a system build-out in Saco. Northern believes that the Staff's proposed Saco TAB incentive mechanism is untimely and unfair to the Company. Northern states that if the Staff believed that such a mechanism was necessary to allocate risk, it had ample opportunity to do so in both Dockets 2015-00146 and the Company's Sanford TAB proposal, Docket No. 2017-00037. *Id.* at 88.

3. Decision

a. Saco TAB Rate Base

The arguments before the Commission on the Saco TAB rate base are essentially identical to those presented regarding the Company's overall rate base. The Company argues that the Commission should use the year-end rate base for its Saco TAB investment and make no adjustments outside of the test year for known and measurable changes. The Staff and the OPA argue that in order to satisfy the ratemaking matching principle, known and measurable changes, including an adjustment for sales growth related to the investment, must be made. As discussed in Section V.A., the Commission's position on year-end rate base is that average-year rate base should be used unless suitable adjustments can be made to match the costs of the year-end adjustment with the known and measurable changes, including sales growth, related to placing those assets into service, associated with the investment. *Bangor Gas*, at 22. With regards to the Saco TAB investment, the Commission finds that the information needed to make the necessary corresponding known and measurable adjustments exists in the record, and the Commission, therefore, approves the Company's proposal to adjust the end of the test year plant balances for the Saco TAB which had been in CWIP at the end of 2016 but had actually been placed in service.

The Staff and the OPA both propose that the Saco TAB rate base be adjusted for the impact of ADIT. Given that the Saco TAB investment was eligible for bonus depreciation under federal taxation rules, the amount of the ADIT offset in the first year of the investment is significant; approximately $800,000. Bench Analysis Exhibit 4 and Morgan Dir. Test at 40. The Commission agrees with the Company, however, that because the Company is currently in a NOL position for federal tax purposes, it is unable to take advantage of the ADITs and recognize the cash benefit that a rate base offset is intended to represent. In addition, while it is uncertain how the IRS would react to a decision of the Commission which began to flow through the benefit of the Saco TAB ADIT at this time, the Commission finds that the Company's argument that such a flow-through would result in a finding by the IRS that the Company was in violation of IRS normalization rules to have merit.

b. Depreciation Expense

The Company proposes using a full year of depreciation on the Saco TAB investment in calculating the Saco TAB revenue requirement. The Company's depreciation expense is based on Mr. Normand's proposed depreciation rates. In its Bench Analysis, Staff proposed that the Saco TAB depreciation expense reflect the recommendations of its consultant, Mr. Dunkel. Both the Staff and the OPA recommend that the Saco TAB rate base be offset with an amount that is included in the revenue requirements for depreciation expense.

Ordinarily, when investments are added to plant mid-year, a half year of depreciation expense is provided for. However, consistent with the objective of including known and measurable changes associated with the year-end Saco TAB investment, the Commission accepts the Company's proposal to include a full year of depreciation associated with providing service to Saco TAB customers in 2017. However, the Commission revises the Company's calculation of the full year depreciation expense consistent with the depreciation rates proposed by Mr. Dunkel for account 380 (Distribution Services) and as adjusted for account 376.4 (Distribution Mains), as discussed in Section V.C.

c. Revenues

The OPA proposes to include as an offset to the Saco TAB revenue requirement $53,964 for operating revenue. The OPA's revenue adjustment is based on Mr. Mierzwa's calculation of the average annual revenue per customer by class which is then multiplied by the number of TAB customers in each class at the end of the rate year. The Staff's proposed revenue adjustment is based on the Company's estimate of 2017 revenue. As discussed above, the Company opposes both the Staff and the OPA proposals as going beyond the test year.

The Company has reported that through July 31, 2017, it did not add any distribution mains or services to its 2016 Saco TAB plant. OPA 006-001. During the January 1, 2017 through July 31, 2017 timeframe, the Company's Saco TAB incremental revenues was $50,108 and the Saco TAB surcharge revenue was $9,070. ODR 008-003. Annualizing these amounts by including the months of September through December 2016 results in an adjustment of $58,059 to revenue requirements for TAB revenues and an adjustment of $10,384 for surcharge revenues. Under the provisions of the Saco TAB, this surcharge revenue should be used as an offset to rate base.

d. Incentive Mechanism

The threshold question in addressing Staff's incentive mechanism proposal here is whether it was contemplated that such a proposal might be put forward in this case when we approved the Saco TAB in Docket No. 2015-00146. The Company takes the position that the only fair and rational interpretation of the Commission's Order approving the Saco TAB is that the Commission intended to look at the costs associated with the Saco TAB investment when the Company sought to include such costs in rates. Northern Brief at 36. The Commission interprets the Company's argument essentially to be saying that the Commission reserved the right to conduct a prudence review of the Company's TAB investments at the time that the Company proposed to include such amounts in rates. Thus, to the extent that the Commission found the initial Saco TAB costs were prudent at the time of the investment, Northern's generally body of ratepayers would be responsible for such costs regardless of whether the Company received revenues to cover the investments. The Commission disagrees that the review was intended to be this limited.

Under the TAB program, instead of assessing an up-front CIAC to recover the costs of main extensions to serve new customers, such investments are recovered through the assessment of a surcharge which is assessed over a 10-year time period. By doing so, the Company has eliminated a significant barrier to expand its footprint and serve new customers. In addition, however, since new customers are no longer paying the upfront charge to recover the investment associated with providing them service, the risk associated with achieving the sales and penetration rates at the levels projected in the Company's TAB modeling has been shifted to Northern's existing customers given that the Saco TAB investment and expenses are included in base rates. In the *Saco TAB Order*, the Commission noted that because of the uncertainty about the projected rate of conversion to natural gas and the discretion afforded the Company to respond, the TAB ratemaking issues would be left open until this proceeding. The Commission was concerned not merely about the costs of the investments, but the uncertainty of sales and how that might impact the recoverability of costs.

Under the Company's plan for the Saco TAB buildout, investment costs are clearly front-end loaded. As discussed in this section, the Company invested $4,132,346 in 2016. In 2017, the Company projected that it would invest an additional $1,750,445 and in 2018 the Company projects spending an additional $874,090. EXM 004-018. After 2018, the Company's annual investments drop off significantly. *See* ODR 004-007. Were the Company's position to be accepted, Northern's ratepayers would bear the significant upfront investment costs and be at risk that the Company's revenue projections would not be realized. It was precisely this risk that the Commission sought to address when it left open the ratemaking issue in the *Saco Tab Order.*

Under the Staff's proposed incentive mechanism, Northern's ratepayers would be at risk for sales which are between 90% and 110% of projected levels. Outside this deadband, the risk would shift to the Company. The Company complains that the parameters of the Staff's plan are completely subjective. The Staff has acknowledged that the bandwidth was based on its judgment of how the risks between ratepayers and shareholders could be reasonably apportioned while accounting for forecast uncertainties. The Commission agrees with the Company that the Staff's selection of the sharing criteria was subjective. However, such incentive mechanisms are often based on judgment. *See Central Maine Power Company, Proposed Increase In Rates,* Docket No. 1992-00345(II), Detailed Opinion and Subsidiary Findings (Jan 10, 1995). On its face, the mechanism appears to be reasonable. Thus, the Commission will adopt the TAB incentive mechanism proposed by Staff on a going forward basis but we do not preclude the Company from coming back with an alternative proposal to address the risk allocation issues discussed here.

VI. REVENUE ALLOCATION AND RATE DESIGN

A. Company Proposal

Figure VI.1 below shows the Company's proposed class revenue allocation, based on the Company's initial filing, which does not include the additional revenue requirement increase of $677,000 proposed in the supplemental testimony of Mr. Chong. The proposal is based on the testimony and cost of service studies provided by the Company's consultants and witnesses Mr. Normand and Ms. Gajewski, both of whom are consultants with Management Applications Consulting (MAC). The MAC consultants provided both an accounting cost of service study (ACOS) and a marginal cost of service study (MCOS). According to the MAC consultants, the cost of service studies indicate that, at current rates, the revenue from the residential classes is substantially deficient and that much higher increases for these classes as compared to other rate classes is needed in order to meet the target revenue levels. However, to moderate the rate impact on residential customers, the MAC consultants placed a cap on the class revenue increase equal to 1.25 times the Company's proposed overall revenue requirement increase.

Figure VI.1

Increase by Customer Class

Class	Existing Revenue [1]	Proposed Revenue [2]	$ Increase	% Increase
Residential Heating (R-2)	11,493,243	13,485,687	1,992,444	17.34%
Residential Non-Heating (R-1)	1,298,049	1,523,127	225,078	17.34%
Low Annual, High Winter Use (G-40/T-40)	9,183,658	10,295,549	1,111,891	12.11%
Low Annual, Low Winter Use (G-50/T-50)	978,814	1,100,402	121,588	12.42%
Medium Annual, High Winter Use (G-41/T-41)	8,618,375	9,687,071	1,068,696	12.40%
Medium Annual, Low Winter Use (G-51/T-51)	1,763,399	1,982,593	219,194	12.43%
High Annual, High Winter Use (G-42/T-42)	5,390,183	6,070,902	680,719	12.63%
High Annual, Low Winter Use (G-52/T-52)	4,202,540	4,735,667	533,127	12.69%

[1] Exhibit DLG/PMN-1G-8, page 2, coulmn R
[2] Exhibit DLG/PMN-1G-8, page 6, coulmn AE

Figure VI.2 below shows the average revenue per ccf by rate class at both existing and the Company's proposed revenue levels, again without the additional amount presented in the Chong Supplemental Testimony. As Figure VI.2 indicates, residential rates are already substantially higher than medium- and high-use commercial/industrial customers.

Figure VI.2

Class	Weather Normalized CCFs [1]	Existing Revenue [2]	Proposed Revenue [3]	Cost per CCF @ Current Rates	Cost per CCF @ Proposed Rates
				Cost per CCF	
Residential Heating (R-2)	14,459,686	$ 11,493,243	$ 13,485,687	$ 0.79	$ 0.93
Residential Non-Heating (R-1)	623,674	$ 1,298,049	$ 1,523,127	$ 2.08	$ 2.44
Low Annual, High Winter Use (G-40/T-40)	14,999,927	$ 9,183,658	$ 10,295,549	$ 0.61	$ 0.69
Low Annual, Low Winter Use (G-50/T-50)	1,406,384	$ 978,814	$ 1,100,402	$ 0.70	$ 0.78
Medium Annual, High Winter Use (G-41/T-41)	22,514,299	$ 8,618,375	$ 9,687,071	$ 0.38	$ 0.43
Medium Annual, Low Winter Use (G-51/T-51)	4,944,842	$ 1,763,399	$ 1,982,593	$ 0.36	$ 0.40
High Annual, High Winter Use (G-42/T-42)	21,458,618	$ 5,390,183	$ 6,070,902	$ 0.25	$ 0.28
High Annual, Low Winter Use (G-52/T-52)	19,015,815	$ 4,202,540	$ 4,735,667	$ 0.22	$ 0.25

[1] Exhibit DLG/PMN-1G-8, page 1, column F
[2] Exhibit DLG/PMN-1G-8, page 2, coulmn R
[3] Exhibit DLG/PMN-1G-8, page 6, coulmn AE

With respect to intra-class rate design, in most cases, the Company proposed relatively higher increases to the monthly customer charges compared to the usage charges. For the usage charges, the Company proposed to maintain the existing arithmetic difference between the charges per usage block in each class which results in relatively higher percentage increases to the higher usage block charges. The proposed rate changes are shown in Figure VI.3 below.

Figure VI.3

Rate Increase

Rate Component	Current Rate	Proposed Rate	% Increase
Residential Non-Heating (R1)			
Customer Charge	$ 25.11	$ 28.85	14.89%
Distribution Charge - First 40 units[1]	$ 0.3755	$ 0.4668	24.31%
Distribution Charge - Excess 40 units	$ 0.2854	$ 0.3767	31.99%
Residential Heating (R2)			
Customer Charge	$ 25.11	$ 28.85	14.89%
Distribution Charge - First 40 units	$ 0.4599	$ 0.5245	14.05%
Distribution Charge - Excess 40 units	$ 0.3520	$ 0.4166	18.35%
General Service: Low Annual, High Winter use (G40) *and* Low Annual, Low Winter use (G50)			
Customer Charge	$ 59.63	$ 68.50	14.88%
Distribution Charge - First 70 units	$ 0.3070	$ 0.3331	8.50%
Distribution Charge - Excess 70 units	$ 0.2834	$ 0.3095	9.21%
General Service: Medium Annual, High Winter use (G41) - Winter Rate			
Customer Charge	$ 174.07	$ 200.00	14.90%
Distribution Charge - First 1,780 units	$ 0.2947	$ 0.3177	7.80%
Distribution Charge - Excess 1,780 units	$ 0.2800	$ 0.3030	8.21%
General Service: Medium Annual, High Winter use (G41) - Summer Rate			
Customer Charge	$ 174.07	$ 200.00	14.90%
Distribution Charge - First 1,000 units	$ 0.2852	$ 0.3080	7.99%
Distribution Charge - Excess 1,000 units	$ 0.2592	$ 0.2822	8.87%
General Service: Medium Annual, Low Winter use (G51) - Winter Rate			
Customer Charge	$ 174.07	$ 200.00	14.90%
Distribution Charge - First 1,780 units	$ 0.2632	$ 0.2844	8.05%
Distribution Charge - Excess 1,780 units	$ 0.2485	$ 0.2697	8.53%
General Service: Medium Annual, Low Winter use (G51) - Summer Rate			
Customer Charge	$ 174.07	$ 200.00	14.90%
Distribution Charge - First 1,000 units	$ 0.2538	$ 0.2750	8.35%
Distribution Charge - Excess 1,000 units	$ 0.2278	$ 0.2490	9.31%
General Service: High Annual, High Winter use (G42) - Winter Rate			
Customer Charge	$ 1,004.76	$ 1,150.00	14.46%
Distribution Charge - First 18,000 units	$ 0.2712	$ 0.2924	7.82%
Distribution Charge - Excess 18,000 units	$ 0.2361	$ 0.2573	8.98%
General Service: High Annual, High Winter use (G42) - Summer Rate			
Customer Charge	$ 1,004.76	$ 1,150.00	14.46%
Distribution Charge - First 6,000 units	$ 0.2260	$ 0.2472	9.38%
Distribution Charge - Excess 6,000 units	$ 0.1888	$ 0.2100	11.23%
General Service: High Annual, Low Winter use (G52) - Winter Rate			
Customer Charge	$ 1,004.76	$ 1,150.00	14.46%
Distribution Charge - First 25,000 units	$ 0.2481	$ 0.2667	7.50%
Distribution Charge - Excess 25,000 units	$ 0.2064	$ 0.2250	9.01%
General Service: High Annual, Low Winter use (G52) - Summer Rate			
Customer Charge	$ 1,004.76	$ 1,150.00	14.46%
Distribution Charge - First 23,000 units	$ 0.1838	$ 0.2024	10.12%
Distribution Charge - Excess 23,000 units	$ 0.1427	$ 0.1613	13.03%

Source: Exhibit DLG/PMN-1G-9

1 Current rate units are ccf, proposed rate units are thm

B. Positions of the Parties

The Company asserts that the majority of its distribution costs are fixed in nature and not driven by usage. Northern Reply Brief at 28. As noted above, Northern also concluded that commercial and industrial classes are subsidizing the residential classes. Northern Brief at 123. In support of its conclusions the Company cites the rather voluminous ACOS and MCOS studies and workpapers prepared by its witnesses Mr. Normand and Ms. Gajewski.

The goal of the Company was to allocate the overall revenue requirement to each revenue class such that the revenue requirement for each class produced an equalized rate of return (8.30%). *Id*. at 121. As noted above, this allocation yielded a very large increase to existing residential class revenue levels, and so the Company imposed a cap limitation on the residential revenue increase of 125% of the overall Company increase and allocated the remaining revenue requirement above the cap to the other classes. *Id*. at 122. After allocating the revenue requirement to each class, the Company determined the intra-class allocation between fixed and volumetric charges. The intra-class allocation was designed to be reflective of the fixed nature of the distribution charges. *Id*. at 122-123.The remaining intra-class revenue requirement not assigned to fixed customer charges was allocated to the block prices in a way that maintained the existing block differentials. *Id*. at 123.

The Company also contends that if the requested revenue requirement is reduced, the reduction should be reflected in the usage charges while maintaining the fixed customer charges as proposed in its filing. *Id*. at 124. According to Northern, this is reasonable because the proposed customer charges are below the actual cost to serve.

The OPA did not present an alternative revenue allocation and rate design proposal but argues that only fixed costs directly related to attaching customers to the system should be included in fixed customer charges. OPA Brief at 41. The OPA asserts that, because Northern's investment decisions for main extensions and new service lines are based on a net present value (NPV) analysis, a customer with higher usage will cause Northern to incur greater investment and other costs than a customer with lower usage. *Id*. at 40. The OPA concludes that low- and high- usage customers therefore do not impose the same level of fixed costs on Northern, and so a finding that a majority of costs are fixed and could therefore be collected through customer charges, violates the principle of cost causation. *Id* at 40-41. The OPA also contends that rate stability and gradualism should be taken into consideration when designing monthly customer charges. *Id*. at 41. Finally, the OPA reasons that if the Commission does not approve the entire revenue increase requested, the reduced amount should be reflected in both the fixed and volumetric charges. OPA Reply Brief at 10.

In its Bench Analysis, Staff expresses some concerns with the Company's analysis and proposal as presented by the MAC consultants. First, Staff stated that if a revenue requirement increase close to what the Company has requested were to be granted, the increase for the residential class would be unduly burdensome as it would result in an increase of nearly 20% for average residential customers, even after applying the Company's 125% revenue increase cap. Bench Analysis at 57-58. Staff deferred making a final recommendation on rate design, but noted that rate design issues such as revenue allocation involve judgement and consideration of factors such as rate stability, the overall level of the revenue requirement increase and potential future rate increases from the TIRA. *Id*. at 58. Staff generally agreed with Northern's conclusion that distribution system costs tend to be fixed in nature.

Staff observed that, although the Company's proposed rate design was informed by the cost of service studies, it ultimately appeared to have been more a matter of judgement. *Id*. at 59. For example, Staff questioned why it was desirable or necessary to maintain a constant dollar-per-ccf differential between rate block usage charges as proposed by the Company, as this seemed to conflict with the Company's position that the cost of service is largely fixed. *Id*. at 59-60.

1. <u>CCF to Therm</u>

Northern proposes to change its current practice of billing on a ccf basis to billing on a therm basis. Gajewski/Normand Dir. Test. at 37. Northern asserts that because heat content, rather than the amount of ccf, dictates the customer's need for natural gas, it is more reasonable to base the Company's distribution rates on therms over ccf. *Id*. at 38. Northern also notes that other LDCs base their distribution rates on therms, as do the Company's affiliated LDCs in New Hampshire and Massachusetts. *Id*. This proposal has not been contested by any party.

2. <u>Telemetering Changes</u>

Northern proposes to adjust charges and fees related to the Retail Choice Program, as found in Appendix A to the Company's Delivery Service Terms and Conditions, to better reflect cost. Leblanc/Sprague Dir. Test. at 38. These changes include: Telemetering Fees for the One-Time Installation of an instrumented or non-instrumented meter; the Monthly Surcharge Fee in lieu of One-time Installation Charge for a non-instrumented meter (optional); and the Monthly (Telemeter) Maintenance Fee. *Id*. Northern is also proposing a Meter Read Charge for when a customer-maintained phone line is not reporting daily telemetered usage and the Company is required to make a specific trip to the customer location at the end of the billing cycle in order to read the meter and obtain the daily usage data. *Id*. In addition, the Company is proposing to update its Turn-On Charge, as found in the Company's Rate Schedules. *Id*. The proposed cost for each service is based on the labor and travel expenses required. *Id*. at 39. These adjustments have not been contested by any party.

C. <u>Discussion and Decision</u>

As noted above, the Company's proposed revenue allocation and rate design are based on the cost of service studies conducted by its consultants. According to the MAC consultants, both the ACOS and the MCOS indicate similar results in terms of: (1) revenue deficiencies in the residential classes; and (2) the fixed nature of most of the costs of the distribution system. The studies, in particular, the ACOS, are premised on the rate base, expenses, and cost of capital reflected in the Company's proposed revenue requirement, as well as income taxes calculated in accordance with the prior tax law. With respect to the MCOS, although it is not based on accounting costs, it does reflect the higher income tax rates that were in effect prior to the recent change.

As discussed in prior sections of this Order, the components of the revenue requirement authorized by the Commission in this proceeding differ in several key respects from the Company's proposal. The authorized revenue requirement also reflects the effects of the new tax law. Although such a "mis-match" may often occur when a utility proposes rate design changes as part of a revenue requirement case, based on the degree of the differences in this case, including the impact of tax-related issues, the Commission cannot find the cost of service studies to be reliable for the purpose of determining class revenue allocations and intra-class rate design. Typically, when rate changes are implemented without reliance on a cost of service study, the changes are made on an equal percentage basis. For example, if the overall Company revenue requirement is to be increased by 4%, the revenue requirement for each class would also be increased by 4%. Thus, given the lack of a reliable cost of service study in this case, the Commission concludes that the revenues from each rate class should be adjusted by the same percentage as the overall change in the Company's revenue requirements. As discussed above, this would result in a slight decrease in the revenues from each class.

With respect to intra-class rate design, however, the Commission agrees with the Company that much of the costs of an LDC distribution system are fixed and do not vary with usage. In the Commission's view, this appears obvious and does not require detailed and precise results of an ACOS or MCOS.[12] As shown below in Figure VI.4, however, the portion of Northern's revenues that are currently recovered though customer charges varies widely across its customer classes, ranging from more than 80% for residential non-heating customers to less than 10% for high use commercial/industrial customers.

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12 In its Brief, the OPA argues that the Company's terms and conditions for new services and main extensions support the proposition that customers with relatively higher usage levels would cause it to incur higher investment and other costs than customers with lower usage. OPA Brief at 40. The Commission finds no support for this proposition in these terms and conditions. On the contrary, the NPV test cited by the OPA would be likely to yield a more favorable outcome in terms of expansion for customers with relatively higher usage because of the relatively higher revenue contribution over the term on the NPV analysis.

Figure VI.4

Revenue by Component			
Class	Existing Revenue [1]	Existing Customer Charge Revenue [2]	Pct Customer Charge
Residential Heating (R-2)	11,493,243	5,749,374	50.02%
Residential Non-Heating (R-1)	1,298,049	1,076,554	82.94%
Low Annual, High Winter Use (G-40/T-40)	9,183,658	4,842,959	52.73%
Low Annual, Low Winter Use (G-50/T-50)	978,814	570,627	58.30%
Medium Annual, High Winter Use (G-41/T-41)	8,618,375	2,195,581	25.48%
Medium Annual, Low Winter Use (G-51/T-51)	1,763,399	521,160	29.55%
High Annual, High Winter Use (G-42/T-42)	5,390,183	467,213	8.67%
High Annual, Low Winter Use (G-52/T-52)	4,202,540	519,461	12.36%
Total	42,928,261	15,942,929	37.14%

[1] Exhibit DLG/PMN-1G-8, page 2, coulmn R

[2] Exhibit DLG/PMN-1G-8, page 2, coulmn Q

Given this variation, the Commission finds that, for certain classes, specifically, the Medium and High Annual Use classes (G-41/T-41; G-51/T51; G-42/T-42; and G-52/T-52) the revenue requirement decrease discussed above should be allocated in full to the usage charges, and there should be no change to the customer charges. Specifically, the usage charge for each block within these classes should be reduced by the same percentage. This would result in a slight change in the portion of the revenues recovered through the customer charge in each of these classes. For all other classes, specifically the Residential and Low Annual Use classes, the customer charges and usage charges should be reduced by the same percentage.

VII. TARGETED INFRASTRUCTURE REPLACEMENT MECHANISM

A. Background

The original TIRA mechanism (TIRA 1) was approved by the Commission in the Company's most recent base rate case. *Northern Utilities Inc. d/b/a/ Unitil, Proposed Increase in Rates*, Docket No. 2013-00133 (Dec. 27, 2013) *(2013-00133 Order)*. TIRA 1, which was established for a four-year period, is a "capital tracker" that allows for recovery in rates of the costs associated with certain Company capital programs; specifically, the CIRP, the Unprotected Steel Replacement Program (UPS), and the Farm Tap Regulator Program (FTR).

The CIRP is a fourteen-year (2011-2024) construction project to replace approximately 70 miles of cast iron, wrought iron, and unprotected steel pipe in the Company's low pressure distribution system in Portland and Westbrook and to perform related system improvements. The CIRP also involves a pressure conversion from low-pressure to intermediate pressure, which will allow the system to better accommodate customer growth. The CIRP was motivated by safety concerns stemming from the age and leak-prone nature of this pipe in this portion of the Company's system. The parameters of the CIRP, including the project scope and schedule, were approved by the Commission in its Order Approving Stipulation in Docket No. 2008-00151. *Public Utilities Commission, Investigation Into Cast Iron Replacement Program in Portland and Westbrook for Northern Utilities Inc. d/b/a Unitil*, Order (July 30, 2010) *(CIRP Order)*.

The UPS program, which began in 2014, is a project to replace approximately 10 miles of unprotected steel mains and services on the Company's intermediate pressure system. As with the CIRP, the UPS program was motivated by safety concerns about the potential for corrosion of the unprotected pipe. The FTR program, which also began in 2014, involves the replacement of more than 100 direct buried pressure regulating devices with new regulators that will be installed in an enclosure to shield the device from direct contact with the ground.

Pursuant to TIRA 1, rates have been adjusted on May 1 of each year (2014-2017) to reflect recovery of investments made in the prior calendar year (2013-2016) for the CIRP, UPS and FTR programs, subject to certain conditions. The conditions include the Company meeting certain cost and schedule metrics which are set by reference to the Company's Earned Value Management (EVM) model. The last rate adjustment under TIRA 1 was effective May 1, 2017.

As described by the Company in various filings, EVM is a valuable and widely-used project management practice to track performance. EVM requires an up-front, well-defined scope of work and budget for each discrete component of a project, as well as defined metrics. Performance can then be tracked by comparing actual work completed and actual cost against the metrics. The Company's EVM for the CIRP, UPS, and FTR programs established planning estimates on a per unit basis for each component of the program for: (1) the quantity of units to be installed in each year; and (2) the cost per unit. Given the length, scope and complexity of projects like the CIRP, EVM allows overall progress to be tracked even if actual work on a year-to-year basis diverges from the original plan. As discussed below, certain key elements of TIRA 1 were established based on the EVM that had been developed by the Company prior to starting construction on the CIRP, UPS, and FTR programs and, at least in the case of the CIRP, prior to its TIRA proposal.

Under TIRA 1, annual rate adjustments were subject to the Company meeting two performance metrics; one that measured its cost performance and one that measured its schedule performance. The Cost Performance Index (CPI) and Schedule Performance Index (SPI) were set by reference to the Planned Value (PV) and Earned Value (EV) at a given point during the project, as reflected by the values in the Company's EVM model. Specifically, the aggregate of the per unit quantity and cost values reflected in the EVM established the PV for each year against which actual performance was tracked. The EV, then, was calculated as the product of the units actually installed in each year on a cumulative basis and the originally estimated cost per unit.

The CPI was defined by the relationship between Earned Value and Actual Cost, specifically EV/AC. If the cumulative Earned Value was equal to, or greater than, the cumulative Actual Cost (which translates to a CPI => 1.0), the project would be considered to be under budget. Conversely, if the Actual Cost exceeded the Earned Value (CPI < 1.0), the project would be considered to be over budget. The SPI was defined by the relationship between Planned Value and Earned Value, specifically, EV/PV. If the Earned Value exceeded the Planned Value, (SPI => 1.0), the project would be considered to be ahead of schedule and, if not, the project would be considered to be behind schedule.

Under TIRA 1, a rate adjustment would be made only if the Company was meeting both the CPI and the SPI. Specifically, both indices must, on a cumulative basis be equal to or greater than 1.0 since the start of the program. If either the CPI or the SPI was less than 1.0, TIRA 1 would have been suspended pending a review by the Commission of the reasonableness of the Company's performance. To date, as shown in Figure VII.1 below, in each year the Company has met both the CPI and SPI, although, in some years, the CPI has been very close to 1.0.[13]

Figure VII.1

	Annual		Cumulative	
Year	CPI	SPI	CPI	SPI
2011	1.19	1.05	1.19	1.05
2012	1.12	1.15	1.15	1.11
2013	0.95	1.39	1.08	1.19
2014	0.98	0.97	1.05	1.12
2015	0.89	1.34	1.004	1.17
2016	1.04	0.99	1.01	1.14

The annual rate increase under TIRA 1 was capped at 4% (Rate Cap). TIRA 1 also included an Earning Sharing Mechanism (ESM) pursuant to which earnings between 10% and 11% would be shared on a 50/50 basis between the Company and ratepayers and earnings in excess of 11% would be returned to ratepayers. Neither the Rate Cap nor the ESM was triggered under TIRA 1. Figure VII.2 below provides the percentage rate increases for each year of TIRA 1.

13 Figure VII.1 includes the CPI and SPI for the entire construction period, a portion of which pre-dates the TIRA.

Figure VII.2

TIRA 1 Rate Adjustments

Docket	2014-00059	2015-00054	2016-00033	2017-00035
Effective Date	05/01/2014	05/01/2015	05/01/2016	05/01/2017
Revenue Requirement Year	2013	2014	2015	2016
Weather Normalized Distribution Revenues	$34,820,388	$38,245,776	$40,571,502	$42,209,471
TIRA Rate Base	$ 7,929,942	$16,229,488	$25,880,698	$33,274,588
Incremental TIRA Revenue Requirement	$ 1,287,956	$ 1,154,626	$ 1,539,337	$ 1,102,389
Total TIRA Revenue Requirement	$ 1,287,956	$ 2,442,582	$ 3,981,919	$ 5,084,307
Increase as % of Distribution Revenues	3.70%	3.02%	3.79%	2.61%

Source of data: Company filing in Docket No. 2017-00035; Exhibit DLC-1, p.1

Described generally, the TIRA rate adjustments in each year reflected the difference between the CIRP, UPS and FTR related revenue requirement in the prior calendar year and the revenue requirement for these programs for the calendar year before that. Under TIRA 1, the return on rate base was 11%, which was less than the return on the rest of the Company's rate base allowed by the Commission in Docket No. 2013-00133.

B. Actual Costs and Revised EVM model

As described in the Leblanc/Sprague testimony, the Company is proposing to amend the scope and cost of the CIRP, UPS, and FTR programs to reflect its clearer understanding of the requirements of the program gained from almost seven years of construction experience. According to Leblanc/Sprague: "Northern has a clearer understanding of the actual condition and composition of its underground distribution system, which allows the Company to more accurately estimate the scope of work that remains necessary to complete the CIRP/UPS/FT." Leblanc/Sprague Dir. Test. at 4. The Company amended its EVM model accordingly, and is proposing to use the amended EVM model to measure the CPI and SPI under its proposed TIRA extension.

During the first several years of construction of the CIRP, UPS and FTR programs, actual costs exceeded the Company's original estimates by about $9.1 million, or approximately 33%. Figure VII.3 below provides a summary of these cost variances by category.

Figure VII.3

Northern Utilities CIRP/UPS/FT EVM
Original Plan vs. Actual Cost; 2011-2016
Nominal Dollars

Item	Original Estimate	Actual Cost	$ Delta Actual Cost/ Original Estimate	Percent Delta Actual Cost/ Original Estimate
CIRP				
Main Installation	$ 9,651,110	$18,158,158	$ 8,507,047	88.1%
Critical & System Valves	$ 84,529	$ 0	($ 84,529)	-100.0%
Service Renewals	$10,932,513	$ 7,850,818	($3,081,695)	-28.2%
Meter Work	$ 1,924,978	$ 1,708,993	($ 215,985)	-11.2%
System Uprates	$ 2,420,197	$ 2,174,371	($ 245,826)	-10.2%
Regulator Stations	$ 223,139	$ 879,489	$ 656,350	294.1%
System Improvements	$ 917,035	$ 2,434,357	$ 1,517,323	165.5%
UPS				
Main Installation	$ 702,427	$ 2,365,401	$ 1,662,974	236.7%
Service Renewals	$ 408,599	$ 489,563	$ 80,964	19.8%
Meter Work	$ 31,829	$ 47,234	$ 15,405	48.4%
FTR				
Farm Tap Regulators	$ 401,821	$ 687,821	$ 286,000	71.2%
TOTAL (w/o PM and contingency)	$27,698,178	$36,796,206	$ 9,098,027	32.8%

Source of data: Company filing in 2017-00035 and response to EX-002-005 in 2017-00065.

As shown above, the vast majority of the difference between estimated and actual costs is attributable to main installations. According to the Company, these main-related increases were primarily caused by two factors: (1) the need to direct-bury rather than insert new main; and (2) unanticipated permitting and compliance costs resulting from stricter-than-expected enforcement of codes and ordinances by the City of Portland which principally consists of street opening permits, pavement restoration and working conditions (e.g., night and weekend work). These two factors are related because compliance with Portland's street opening permit process involves factors that may also affect the direct bury process, e.g., the pavement restoration process.

Regarding the need to direct bury more pipe, the Company stated that it is more expensive to install a mile of main by direct bury when compared to pipe insertion.[14]

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14 "Direct bury," also referred to as "open trench construction," requires that a trench for the main be excavated to the appropriate depth for the entire length of the main being installed. After the main has been lowered into the trench it is backfilled, compacted and the pavement is restored. "Pipe insertion" is a construction technique that allows a new plastic main to be installed inside a larger existing underground low-pressure cast iron or steel gas main. Pipe insertion provides significant cost savings over direct bury construction of a new replacement main, primarily due to the lack of need to open a trench for the entire length of the new main being installed.

When the cost of the CIRP was initially estimated, the Company believed it would need to replace 69 miles of cast iron and unprotected steel main and that about 65% of the new main (*i.e.*, about 45 miles) could be installed using insertion. Based on this ratio of 65% insertion to 35% open trench, the Company derived a blended average per mile cost for main installations of $303,937. During the first six years of the CIRP, however, the Company stated it was only able to use insertion for about 43% of the new mains installed. Because a greater proportion of mains were being replaced by the more expensive open trench method than initially estimated, the actual average cost per mile of installed mains was much higher than the original blended cost estimate. LeBlanc/Sprague Dir. Test. at 13.

As noted above, the Company is proposing to revise its EVM model to reflect its expected scope and cost for the remaining years of construction (2017-2024). The revised metrics are based on the Company's experience with the project scope and costs over the past several years and are further informed by the terms of its contract with its construction contractor for the project, NEUCO.[15] The metrics also include a contingency of ten percent, as well as an additional amount of approximately eight percent for project management. Leblanc/Sprague Dir. Test. at 31. Compared to the original EVM, the revised EVM reflects an increase in project costs of about $15 million, or 30%, during these years. Figure VII.4 below shows the variance by category.

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15 The NEUCO contract has been extended through 2021 with an option for an additional four-year renewal covering the period 2022 – 2025. Leblanc/Sprague Dir. Test. at 32.

Figure VII.4

Northern Utilities CIRP/UPS/FT EVM
2017 - 2024 Comparison
Real 2017$

Item	Original EVM Total Cost 2017 2024	Updated EVM Total Cost (2017 - 2024)	$ Delta Total Cost	Percent Delta Total Cost
CIRP				
Main Installation	$13,895,865	$24,066,263	$ 10,170,398	73.2%
Critical & System Valves	$ 144,504		($ 144,504)	-100.0%
Service Renewals	$12,401,031	$13,702,036	$ 1,301,005	10.5%
Meter Work	$ 2,303,222	$ 2,563,237	$ 260,015	11.3%
System Uprates	$ 1,407,107	$ 2,750,715	$ 1,343,608	95.5%
Regulator Stations	$ 390 ,225	$ 156,972	($ 233,253)	-59.8%
System Improvements	$ 2,385,799	$ 821,904	($ 1,563,895)	-65.6%
UPS		$ 0	$ 0	
Main Installation	$ 4,839,026	$ 6,610,233	$ 1,771,207	36.6%
Service Renewals	$ 2,951,815	$ 3,807,182	$ 855,367	29.0%
Meter Work	$ 234,029	$ 323,395	$ 89,366	38.2%
FTR		$ 0	$ 0	
Farm Tap Regulators	$ 767,909	$ 557,083	($ 210,826)	-27.5%
SubTotal	$41,720,532	$55,359,020	$ 13,638,488	32.7%
PM and Contingency	$ 8,260,665	$ 9,721,044	$ 1,460,379	17.7%
Total Project Cost	$49,981,197	$65,080,064	$ 15,098,867	30.2%

Source of data: Company filing in 2017-00035 and Exhibit CLSK-1 (corrected)

C. Positions of the Parties

1. Length of Construction Term for the CIRP Program

In its Brief, the OPA urges the Commission to expand the construction period for the CIRP program from 2024 to 2027, which the OPA asserts will afford the Company flexibility in the deployment of capital resources while also mitigating the effect of those investments on ratepayers. OPA Brief at 29.

In its Reply Brief, Northern argues that such an extension is unnecessary and not permissible under the CIRP Order. Northern Brief at 24. Northern notes that although the CIRP Order contemplated a potential extension, the context was where cost savings could potentially be achieved through coordination with state and municipal construction projects, and did not indicate a general willingness to extend the term. *Id.* at 25.

Northern also disputes the OPA's suggestion that it will not be able to complete the work by the end of 2024. *Id.* Finally, Northern rejects the OPA's argument that extending the term would result in overall cost savings, arguing instead, that because of overall inflation, an extension would be more likely to increase costs. *Id.*

2. TIRA Design

Northern is seeking to extend and modify the TIRA. Northern requests that the Commission extend the TIRA for four more years to cover ClRP/UPS/FT construction during 2017-2020 (TIRA 2). Northern argues that the fundamental structure of TIRA 1 has been successful and that there is no reason to change the overall structure of the TIRA. Northern Brief at 102. However, Northern does request minor modifications to the TIRA. Northern's proposed modifications to the TIRA include: (1) including the costs associated with the installation of certain EFVs within the investments subject to TIRA 2; (2) increasing the rate cap from 4% to 5% of weather-normalized distribution revenues; and (3) relying upon EVM metrics generated by a re-based EVM model. *Id*.

While Northern requests a four-year term for TIRA 2, for the reasons noted below, Staff's Bench Analysis recommended an eight-year term (2017-2024). Northern states that an eight-year term would lock the Commission, customers, and the Company into the TIRA 2 without the ability of making any adjustments that may be both necessary and appropriate during that time. *Id*. at 106. Northern states that a shorter TIRA term will not weaken the incentives for cost control or provide the Company an opportunity to "manage to the metrics," as suggested in the Bench Analysis. *Id*. at 106-107.

Northern points out that the Company has a fixed price contract with NEUCO for the next few years and therefore, Northern states, it has already controlled the unit costs of construction through 2021 by locking them in contractually. *Id*. at 107. However, Northern states that it has no way to control for field conditions and argues that no TIRA incentive is capable of fixing or reducing the scope of work necessary to complete the project. *Id*. at 108. Further, Northern states that there is no evidence in the record that Northern failed to properly manage costs during the term of TIRA 1. *Id*. at 107. Northern argues that the TIRA 2 proposal outlined in the Staff's Bench Analysis would penalize Northern when it experiences field conditions beyond its control and does not take into consideration the magnitude by which the Company may miss the CPI or SPI. *Id*. at 113.

Northern recommends that the rate cap be increased from 4% to 5% for TIRA 2. Northern argues that a rate cap of less than 5% would improperly limit its recovery of its investments in the CIRP/UPS/FT and could lead to the very rate shock that the TIRA rate cap is intended to avoid. *Id*. at 118. Northern is also proposing to include EFVs in the TIRA. Northern states that it is proposing to include the EFVs because they are significant safety improvements, but are non-revenue producing. Chong Dir. Test. at 41. Finally, the Company is proposing to increase the O&M offset in the TIRA, based on its recent experience.

The OPA does not object to the renewal of the TIRA, however, it does oppose the Company's request to alter certain aspects of the program. OPA Brief at 29. The OPA states that Northern has failed to show that many of its proposed changes to the TIRA program properly balance the needs of the Company and ratepayers and that TIRA 1 has already had considerable impact on customers since its implementation due to the annual rate increases over the last four years. Id. at 27-29. The OPA argues that Northern's requested increase in the rate cap from four to five percent would discourage the Company from keeping costs under control, would burden ratepayers, and would allow the Company to recover costs that are not solely driven by safety. *Id*. at 33.

The OPA agrees with the Company's proposed increase of the O&M savings factor. *Id*. at 32. The original TIRA included an O&M offset to reflect the reduction in expenses that would occur as leak-prone pipes were replaced. *Id*. OPA accepts the Company's proposal and defers to the analysis in the Bench Analysis with respect to the application of an inflation adjustment. *Id*. Finally, based upon the OPA's recommended rate of return, the OPA states that the pre-tax rate of return for the TIRA should be 9.97 percent. *Id*. at 34.

In its Bench Analysis, Staff recommends that the TIRA be extended but proposed modifications to Northern's TIRA 2 proposal. Staff's primary concern was that any TIRA extension should reflect design changes that would provide stronger incentives for cost control than were provided by TIRA 1. Staff notes that when the CIRP was initially approved, the Commission stated that any associated rate mechanism must provide: "(an) incentive for Northern to contain the overall costs of the project… (and) will also include disincentives for cost overruns." Bench Analysis at 49, citing *CIRP Order* at 18.

Staff notes that the extent to which TIRA 1 effectively provided such incentives is unclear. Staff notes that Northern may have not have taken all the steps it could have taken to address the cost increases such as more strenuously negotiating with the City of Portland regarding street opening conditions. Staff notes that, although the Company stated in its testimony that it has tried to negotiate with the City over these conditions, there is little evidence in the record to substantiate this claim. According to Staff, although the record shows that the Company and the City had numerous discussions related to the costs for street opening permits and a fine imposed by the City, there is little evidence that the Company sought to negotiate with the City over the actual street opening permit conditions to which it attributes the cost increases such as night and weekend work and traffic control plans. Staff notes further that there is little evidence provided to document what actual conditions were placed on the Company by the City through the permit process because they are not stated in the permits or documented elsewhere. Finally, Staff notes that in response to questioning, the Company acknowledged that it did not attempt to negotiate with the City regarding these requirements because the Company assumed that the City would not be willing to negotiate. *Id*. at 36-41.

Staff notes that the Company's management of the project under TIRA 1 may, in part, be correlated with the structure of TIRA 1 because it provided an opportunity for the Company to rebase its EVM and to seek to use the rebased EVM for TIRA 2. *Id*. at 51. While Staff accepted the Company's revised EVM for TIRA 2, Staff also concluded that no further revisions to the EVM should be made during TIRA 2 and thus recommended that the TIRA be extended through the scheduled end of the project, rather than the four-year term proposed by Northern. *Id*. at 50-51. Without a built in "second (or third) bite at the EVM apple," Staff concluded that Northern would have a stronger incentive for cost control and prevent "managing to the metrics" behavior that may have occurred under TIRA 1. *Id*. at 51. Alternatively, if the Commission were to conclude that a TIRA would not likely provide sufficient incentives to manage project costs, Staff notes that the TIRA could be eliminated and the capital costs of the CIRP, UPS and FTR programs treated just like the Company's other capital investments. Although the TIRA programs are significant and, to a large degree, not revenue producing, the same can be said for other categories of the Company's capital investment. *Id*. at 49-50.

As noted above, for the purpose of TIRA 2, Staff accepts the Company's revised metrics which, as noted by the Staff, reflect substantial increases but which are based on the Company's several years of experience with the projects. Staff agreed that the CPI and SPI should continue to be used to measure performance but suggested two changes to how the TIRA would operate with respect to these metrics. *Id*. at 52. Specifically, if either of the metrics (on a cumulative basis starting with 2017) is less than 1.0, there would be no TIRA rate adjustment that year, however, in contrast to TIRA 1, the TIRA would remain in place. *Id*. If the Company brought the metric back up to 1.0 or greater in the following year, the rate adjustment would occur at that point and the Company could recover the entire revenue requirement amount attributable to both years. *Id*. The Staff noted that having the TIRA remain in place if an index drops below 1.0 provides an incentive for the Company to manage the program to bring the indices back to 1.0. *Id*.

In addition, Staff proposed to include an ROE up-side adjustment to provide an additional incentive for the Company to control the costs of the TIRA projects. Specifically, if the CPI was equal to 1.0, the ROE would be equal to the Staff recommended ROE for the Company's rate base. *Id*. at 52-53. The ROE would then be subject to an increase based on a CPI range of 1.0 to 1.3, the upper end of which reflects Actual Costs being about 25% below the Earned Value on a cumulative basis in each year. *Id*. at 53. The upper end of the ROE range would be 300 basis points above the Staff recommended ROE, or 12.5%. *Id*. Additionally, Staff recommended that the TIRA rate of return be subject to an annual adjustment to reflect applicable changes to the cost of long-term debt. *Id*.

Staff recommended that Northern's proposal to include costs associated with the installation of EFVs in rate base for TIRA 2 be rejected. *Id*. at 46-47. Staff noted that simply because a cost has a safety benefit and is non-revenue producing does not mean it should be part of an automatic rate adjustment mechanism like the TIRA. The Company has substantial other costs that are both safety-related and non-revenue producing that are not included in the TIRA. Furthermore, the Staff notes that the Company has not received a single request for an EFV since it provided the required notice to customers in April, 2017. *Id*.

The Staff agreed with Northern's proposal that the O&M Offset should be updated and based on the Company's proposed $7,614 per mile offset. *Id*. at 33. However, given that the O&M expenses that would be avoided are subject to inflation- driven increases, Staff proposed that the offset be increased each year to reflect general inflation. *Id*.

Staff did not support Northern's proposal to increase the TIRA rate cap from 4% to 5%. *Id*. at 48. Staff stated that the Company's conclusion that the 4% rate cap was too low did not take into account the increased revenue associated with customer growth, nor any base rate increase that would result from the present proceeding. *Id*. at 48-49.

Staff recommended continuing an earnings sharing mechanism, but proposed several modifications. *Id*. at 54. Going forward, the earnings sharing trigger points would be adjusted to reflect the ROE determined in this case. *Id*. Any earnings that result in an ROE greater than 9.50%, up to and including 10.50%, would be shared 50/50 with customers. If the ROE is greater than 10.50%, the earnings returned to customers would be 50% of all amounts from 9.50% to 10.50% and 100% of all amounts above 10.50%. *Id*. Finally, the Staff proposed the ESM be structured so that any ROE incentive earned by the Company would not be taken back by operation of the ESM.

D. Decision

As noted above, the OPA has urged the Commission to expand the construction period for the CIRP program to the end of 2027 rather than 2024. With respect to this recommendation, the Commission finds that the record does not support an extension of the term beyond 2024. Although the Stipulation approved by the Commission in its CIRP Order did contain a provision that the program could be extended to the end of 2027 if warranted by the need or desirability to coordinate construction with municipal projects to achieve cost efficiencies, the CIRP Order itself articulated the Commission's expectation that "the Company shall complete the project in no more than 14 years…" *CIRP Order* at 15. Moreover, as noted by Northern, there is no evidence to support the proposition that an extension to accommodate coordination with municipal projects is necessary or would produce cost savings.

With respect to the TIRA, the Commission agrees with Northern, the OPA and the Staff that the TIRA should be extended. Additionally, the Commission agrees with the Staff that any TIRA extension should incorporate stronger incentives for cost control and disincentives for cost overruns. As noted by the Staff in its Bench Analysis, when it initially approved the CIRP, the Commission anticipated that a rate mechanism would be developed and implemented to govern recovery of CIRP costs and that any such rate mechanism must provide: "(an) incentive for Northern to contain the overall costs of the project… (and) will also include disincentives for cost overruns." *CIRP Order* at 18.

The specific TIRA design issues are discussed below. Any element of the TIRA that is not explicitly changed in this proceeding shall be considered to be the same as approved for TIRA 1, including the reporting requirements and the timing of and methodology used to calculate the percent change in rates.

1. Revised EVM

The Commission adopts the Company's revised EVM to measure cost and schedule performance under TIRA 2. Although the revised EVM reflects costs that are substantially higher than original EVM, the costs are generally reflective of the Company's actual experience to date. The original EVM was developed, at least in part, based on system records maintained by Northern's predecessor that appear not to have been fully accurate or complete. For example, going into the CIRP, Northern expected that it would be able to replace about 65% of the cast iron main by insertion and only the remaining 35% would require the more expensive open trench method. During the first six years of the project, however, due to the condition and location of the existing mains, the Company was able to use insertion for only about 43% of the main replacements which resulted in actual costs per mile for main installation being much higher than originally estimated. Leblanc/Sprague Dir. Test. at 13.

The revised EVM is informed by several years of experience with the projects and the project scope for the remainder of the term is established using detailed engineering plans developed by the Company. In addition, the unit costs are informed by pre-determined prices under the contract with the Company's construction contractor for the TIRA projects (NEUCO), which was recently extended through 2021 with an option for an additional extension through 2025.

2. <u>Term</u>

The Commission agrees with the Staff that the term of TIRA 2 should extend through the end of construction for the TIRA projects which is expected to be 2024. Given the Company's several years of experience with the TIRA projects, the fixed-cost nature of its contract with NEUCO, and the inclusion of a ten percent contingency, the revised EVM should provide a reasonable basis against which to track performance and establish rate-making parameters for the remainder of the construction period. The Commission agrees with the Staff that the potential for another EVM rebase weakens the Company's incentives for cost control and, moreover, weakens the value of the EVM itself as a project management and tracking tool.

3. <u>Metrics and Incentives</u>

The Commission agrees with the Company and the Staff that metrics used in TIRA 1 (i.e., CPI and SPI) should be used to measure performance under TIRA 2. The Commission does not agree with either the Company or the Staff, however, with respect to how the indices would operate.

Under the Company's proposed approach, it could suspend the TIRA if one of the indices fell below 1.0 and request that the Commission review the reasonableness of its performance. If its performance was found to be reasonable, the Company could recover the TIRA investments and re-instate the TIRA. Under the Staff's proposed approach, if one of the indices fell below 1.0, the Company would forego recovery of any of its investment in the prior year and the TIRA would remain in place with the potential that the investment could be recovered in a subsequent year. The Commission finds neither of these approaches to be ideal. The Company's proposed approach weakens its incentives to efficiently manage the project and introduces the potential for requiring ongoing regulatory processes to review the reasonableness of the CIRP/UPS/FT project costs and schedules. Such ongoing regulatory review is not consistent with an incentive rate mechanism like the TIRA. With respect to the Staff's proposed approach, the binary, or "all or nothing" nature of how it treats cost recovery if an index is less than 1.0 is overly restrictive.

Thus, rather than adopt either of these approaches, the Commission finds that the amount of TIRA rate base reflected in the TIRA revenue requirement and rate adjustment each year should be a function of the cumulative CPI and cumulative SPI as of the end of the prior calendar year, with calendar year 2017 being Year 1 of the period. Specifically, a new, blended metric (Blended Performance Index, or BPI) would be used to determine the percent of the TIRA rate base that will be included in rates. The BPI would reflect both the cumulative CPI and SPI as follows:

$$BPI = 1 – ((1 – \text{CPI Factor}) + (1 – \text{SPI Factor}))$$

The CPI and SPI Factors would be equal to the cumulative CPI or SPI unless the CPI or SPI was greater than 1.0, in which case the corresponding Factor would be 1.0. Thus, the BPI reflects each of the indices independently from the other. Stated another way, for example, the operation of the BPI will prevent poor performance on the cost side from being offset by good performance on the schedule side.

The amount of the TIRA rate base included in the revenue requirement and rate adjustment in any given year would be the product of the BPI and the TIRA rate base as of the end of the prior calendar year. An illustration of this calculation is shown below in Figure VII.5 below.

Figure VII.5

TIRA 2
Illustration of BPI Application

CPI = EV/AC; SPI = EV/PV. Both are determined on a cumulative basis.
IF CPI > 1, CPI Factor = 1.0. IF CPI < 1, CPI Factor = CPI
IF SPI > 1, SPI Factor = 1.0. IF SPI < 1, SPI Factor = SPI
TPI = 1 - ((1 - CPI Factor) + (1 - SPI Factor))

	TIRA Rate Base	Cumulative CPI	CPI Factor	Cumulative SPI	SPI Factor	Cumulative Blended Performance Index (BPI)	Rate Base Adjustment Factor %	Rate Base Used for TIRA Cumulative RevReq Calculation
2017	$ 5,500,000	1.040	1.000	1.100	1.000	1.000	100.0%	$ 5,500,000
2018	$11,500,000	0.970	0.970	1.100	1.000	0.970	97.0%	$11,155,000
2019	$18,000,000	0.980	0.980	0.970	0.970	0.950	95.0%	$17,100,000
2020	$23,500,000	0.950	0.950	0.960	0.960	0.910	91.0%	$21,385,000
2021	$31,700,000	1.100	1.000	1.150	1.000	1.000	100.0%	$31,700,000
2022	$36,700,000	0.970	0.970	1.000	1.000	0.970	97.0%	$35,599,000
2023	$42,100,000	0.930	0.930	1.000	1.000	0.930	93.0%	$39,153,000
2024	$52,400,000	0.970	0.970	1.200	1.000	0.970	97.0%	$50,828,000

This approach addresses the Company's concerns about the "all or nothing" nature of the Staff's proposal while also addressing the Staff's goal of providing stronger incentives for cost containment than were provided by TIRA 1.

4. Rate Cap

The Commission agrees with the OPA and Staff that the TIRA Rate Cap should remain at 4%. Given expected sales growth and future rate increases (including from the TIRA), the need to increase the Rate Cap at this time is not evident. However, given the length of the TIRA 2 term, the Company may seek Commission approval to adjust the Rate Cap if it has been exceeded two times.

5. EFV

The Commission finds that EFVs should not be included in the TIRA. As noted by the OPA and Staff, the EFV-related costs are not likely to be substantial and, thus, it is not appropriate to include them in a capital tracker mechanism like the TIRA. The Commission agrees with Staff that simply because a cost has a safety benefit and is non-revenue producing does not mean it should be part of an automatic rate adjustment mechanism. Moreover, the fact that the Company has not received a single request for an EFV since it provided the required notice to customers last April indicates that EFV-related costs are unlikely to be significant.

6. O&M Offset

The Commission finds that the O&M Offset should be revised and, at this point, finds the Company's proposed offset amount to be reasonable. However, given the length of the TIRA 2 term and the fact that these O&M expenses are influenced, in part, by inflation, the Offset will be reviewed for possible adjustment at the time of the 2020 TIRA adjustment.

7. Earnings Sharing

As was the case under TIRA 1, the Commission finds that under TIRA 2 there should be an overall earnings sharing mechanism to ensure that the TIRA does not result in excess profits for the Company. Under TIRA 1, the ESM allowed the Company to retain all earnings that result in a ROE up to, and including, 10%. Any earnings that result in an ROE greater than 10%, and up to and including 11%, were shared 50/50 with customers. For any year in which the ROE was greater than 11%, the earnings returned to customers would be 50% of all amounts from 10% to 11% and 100% of all amounts above 11%. The ROE was calculated annually based on the calculation of the Return on Common Equity Subject to MPUC Jurisdiction as submitted in the Company's Annual Report, with modifications to include weather normalization and unbilled revenue.

The ESM under TIRA 2 would be structured similarly, but the earnings sharing trigger points would be adjusted to reflect the ROE set in this case which as noted above, is 9.50%. Based on this ROE, under the ESM, the Company would retain all earnings up to, and including, an ROE of 9.50%. Any earnings that result in an ROE greater than 9.50%, up to and including 10.50%, would be shared 50/50 with customers. For any year in which the ROE is greater than 10.50%, the earnings would be returned to customers. The mechanism for implementing the earnings sharing provisions under TIRA 2 would remain the same as under TIRA 1.

8. TIRA Rate of Return

The Commission finds that the rate of return established in this proceeding for the Company overall should also apply to the TIRA 2 rate base. As noted, however, the operation of the TIRA adjustment mechanism requires a pre-tax ROE and WACC. Thus, the rate of return applicable to the TIRA calculations will be 9.38% as stated above. This rate of return will remain in effect for TIRA adjustments until such time as the Commission establishes a different cost of capital in a future rate proceeding.

9. ROE Incentive Mechanism

As noted above, Staff proposed to include an ROE up-side adjustment to provide an additional incentive for the Company to control the costs of the TIRA projects. Specifically, Staff proposed a potential increase to the ROE of up to 300 basis points for CPI results above 1.0. Although the Commission agrees that, in principle, mechanisms like this can provide potential benefits to ratepayers, in this case the record does not sufficiently demonstrate that any potential benefits from the Staff's proposed ROE Incentive Mechanism would likely outweigh the costs. Thus, the Commission cannot find that the ROE Incentive Mechanism should be adopted.

10. <u>Company Option</u>

Finally, the Commission finds that TIRA 2 should be optional for the Company. The Company may decline to implement TIRA 2 at the outset, or may opt out of it at any point during the term. If the Company declines to implement, or opts out of the TIRA, further recovery of CIRP/UPS/FTR investments would be allowed only through the traditional ratemaking processes. Should the Company rely on traditional ratemaking for recovery of its TIRA investment, the Company's recovery of such investment would not be limited by what was previously allowed under the TIRA 2 recovery mechanism. In addition, to the extent that the Company does elect to opt out of TIRA 2, we do not preclude, at this time, the Company from proposing a new TIRA mechanism at a later date. However, such a proposal must be based on changed circumstances and should not be used by the Company as an opportunity to rebase the EVM metrics.

Accordingly, it is

ORDERED

1. That the revised rate schedules filed by Northern Utilities on May 31, 20017 are found to be unjust and unreasonable and are herby rejected.
2. That Northern Utilities shall file revised rate schedules in accordance with the terms of this Order with an effective date of March 1, 2018.
3. That further ratemaking for the Company's Saco Targeted Area Buildout investment shall be in accordance with this Order.
4. That Northern Utilities is authorized to seek recovery of its Targeted Infrastructure Replacement (TIRA) investment in accordance with the terms of the TIRA mechanism approved in this Order.

Dated at Hallowell, Maine, this 28th day of February, 2018.

/s/ Harry Lanphear
Harry Lanphear
Administrative Director

COMMISSIONERS VOTING FOR: Vannoy
Williamson
Davis

NOTICE OF RIGHTS TO REVIEW OR APPEAL

5 M.R.S. § 9061 requires the Public Utilities Commission to give each party to an adjudicatory proceeding written notice of the party's rights to review or appeal of its decision made at the conclusion of the adjudicatory proceeding. The methods of review or appeal of PUC decisions at the conclusion of an adjudicatory proceeding are as follows:

1. Reconsideration of the Commission's Order may be requested under Section 11(D) of the Commission's Rules of Practice and Procedure (65-407 C.M.R. 110) within **20** days of the date of the Order by filing a petition with the Commission stating the grounds upon which reconsideration is sought. Any petition not granted within **20** days from the date of filing is denied.

2. Appeal of a final decision of the Commission may be taken to the Law Court by filing, within **21** days of the date of the Order, a Notice of Appeal with the Administrative Director of the Commission, pursuant to 35-A M.R.S. § 1320(1)- (4) and the Maine Rules of Appellate Procedure.

3. Additional court review of constitutional issues or issues involving the justness or reasonableness of rates may be had by the filing of an appeal with the Law Court, pursuant to 35-A M.R.S. § 1320(5).

Note: The attachment of this Notice to a document does not indicate the Commission's view that the particular document may be subject to review or appeal. Similarly, the failure of the Commission to attach a copy of this Notice to a document does not indicate the Commission's view that the document is not subject to review or appeal.